COZEN O'CONNOR
A Pennsylvania Professional Corporation

February 18, 2020

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VIA HAND DELIVERY

Ms. Aida Camacho-Welch
Secretary
NJ Board of Public Utilities
44 South Clinton Street, 9th Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith ("2020 Base Rate Filing")
BPU Docket No. ________________

Dear Secretary Camacho-Welch:

On behalf of the Petitioner, Jersey Central Power & Light Company ("JCP&L"), enclosed herewith for filing with the Board of Public Utilities ("Board") are the original and 10 copies of JCP&L's Verified Petition and appendices, direct testimony, schedules and exhibits thereto, in its above-captioned "2020 Base Rate Filing."

Please note that certain of the schedules to Exhibit JC-11 (Direct Testimony of Stephanie R. Zieger) contain confidential information. Accordingly, JCP&L is requesting confidential treatment of such information and has included herewith an Affidavit of Confidentiality in support of this request. JCP&L is filing both Confidential and Redacted (Public) versions of Exhibit JC-11 with the Board. A copy of the Confidential version of JC-11 will be provided to the Division of Rate Counsel upon the execution of the standard form of non-disclosure agreement for this matter.

I hereby confirm that copies each of this letter and the enclosed Verified Petition and supporting documents are on this day being duly served by hand delivery upon the Director, Division of Rate Counsel, and upon the Department of Law & Public Safety, Division of Law, as set forth in ¶26 of the Verified Petition. Copies of all such documents are also being transmitted by hand delivery or regular United States mail to the balance of the persons named in the attached Service List for this proceeding.

Kindly stamp the enclosed additional copy of this filing letter with the date and time of receipt by your office, and with the docket number assigned, and return same to the undersigned in the self-addressed postage prepaid return envelope provided.

Your anticipated courtesies and cooperation are deeply appreciated.

Very truly yours,

COZEN O'CONNOR, P.C.

By: Gregory Eisenstark

GE:lg
Enclosures

cc: Service List w/enclosures by hand delivery or US Regular Mail

In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith ("2020 Base Rate Filing")
BPU Dkt. No.: ER________
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STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of **Jersey Central Power & Light Company** For Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith ("**2020 Base Rate Filing**")	:	BPU Docket No. **VERIFIED PETITION**

TO THE HONORABLE BOARD OF PUBLIC UTILITIES:

Petitioner, Jersey Central Power & Light Company (the "Petitioner", the "Company" or "JCP&L"), an electric public utility company of the State of New Jersey subject to the regulatory jurisdiction of the Board of Public Utilities (the "Board"), and maintaining offices at 101 Crawford Corner Rd. Building #1, Suite 1-511, Holmdel, New Jersey 07733 and at 300 Madison Avenue, Morristown, New Jersey 07962-1911, in support of its above-captioned Verified Petition, respectfully shows:

1. JCP&L is a New Jersey electric public utility primarily engaged in the purchase, transmission, distribution, and sale of electric energy and related utility services to more than 1,000,000 residential, commercial and industrial customers located within 13 counties and 236 municipalities of the State of New Jersey.

2. Copies of all correspondence and other communications relating to this proceeding should be addressed to:

Gregory Eisenstark, Esq.
Michael J. Connolly, Esq.
Cozen O'Connor, P.C.
One Gateway Center
Suite 910
Newark, New Jersey 07102

- and –

Mark A. Mader
James O'Toole
Joshua Eckert
Jersey Central Power & Light Company
300 Madison Avenue
Morristown, New Jersey 07962-1911

- and –

Carol A. Pittavino
FirstEnergy Service Company
800 Cabin Hill Drive
Greensburg, PA 15601

- and –

Lauren Lepkoski, Esq.
Teresa Harrold, Esq.
FirstEnergy Corp.
2800 Pottsville Pike
P.O. Box 16001
Reading, PA 19612-6001

INTRODUCTION

3. JCP&L's current base electric distribution rates ("base rates") were established by the Board's December 12, 2016 Order in Docket No. ER16040384, effective January 1, 2017.[1] Since then, JCP&L has not increased its distribution rates for more than three

[1] *I/M/O the Verified Petition of Jersey Central Power & Light Company for Review and Approval of an Increase in and Adjustments to Its Unbundled Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith, et al*., BPU Docket No. ER16040384, Order dated December 12, 2016 ("2016 Rate Case Order").

years, and customers have enjoyed rates well below those of other New Jersey electric distribution companies ("EDCs").

4. During this time JCP&L has made, and continues to make, significant investments in its system in order to enhance its resiliency, service, and reliability for its customers. JCP&L has, and will have, invested $1.028 billion over the last four years, from January 1, 2016 through June 30, 2020, including approximately $162.9 million related to capitalized storm costs and approximately $63.8 million related to JCP&L's Reliability Plus Infrastructure Investment Program ("JCP&L Reliability Plus"). The Company also plans to spend approximately $35 million from June 2019 through June 2020 for additional enhancements, including trimming trees along nearly 3,300 miles of power lines as part of routine operations and maintenance ("O&M") to reduce vegetation-related outages. JCP&L will continue to invest in its system to provide customers with safe and reliable service, and the requested rate increase will help provide the necessary financial support for JCP&L to continue this investment and provide its customers with the level of electric service they have come to expect.

5. JCP&L has also been recognized for its storm restoration efforts in New Jersey over the past three years, as FirstEnergy Corp. ("FirstEnergy") has been awarded the Emergency Recovery Award a total of seven times by the Edison Electric Institute for its emergency response efforts – including JCP&L's restoration efforts following the severe thunderstorms that impacted JCP&L's service territory in May 2018. These commendable storm restoration efforts have occurred in spite of an increasing trend in the number and severity of weather events since the conclusion of the Company's last base rate case in 2016. Specifically, forty percent, or $77 million, of the Company's requested rate relief herein is due to storms and their corresponding costs. As both Governor Murphy and the Board have observed, New Jersey

has been experiencing more severe weather events over the years due to the phenomena of climate change. That, coupled with the configuration of the Company's service territory, which includes both the heavily-forested northwestern area and the central coastal region of the State, has caused JCP&L to have been affected by these severe weather events more than the other utilities in New Jersey.

6. Furthermore, JCP&L has taken steps to financially strengthen its balance sheet. Specifically, FirstEnergy contributed $645 million of equity to JCP&L between 2016 and 2018, allowing JCP&L to redeem $700 million of long-term debt over this period. JCP&L did not pay a dividend to FirstEnergy during the period of 2014 to 2018. In addition, JCP&L's qualified pension plan received contributions of $222 million since December 2016, thus helping to reduce its unfunded liability. These credit-supportive actions strengthened JCP&L's financial position and resulted in positive rating actions by all three credit rating agencies (Moody's, S&P, and Fitch).

7. As a result of JCP&L's extensive storm-related work and capital investments, its current base rates are not sufficient for the Company to earn an appropriate rate of return on its rate base or to recover its annual O&M expense. As a result, JCP&L is proposing a rate increase of $186.9 million on an annual basis, representing an overall average increase in JCP&L rates of 7.8%. This base rate proceeding will provide an opportunity for JCP&L's rates to be properly adjusted to allow the Company to attract the necessary capital resources to continue to provide its customers with safe and reliable electric distribution service, as well as recover previously-incurred storm costs. Importantly, following this necessary increase in rates, JCP&L's residential rates (RS) will continue to be the lowest compared to other New Jersey's other EDCs.

2020 BASE RATE FILING

8. This filing uses a test year of the twelve months ending June 30, 2020. The filing includes six months of actual data (July 1, 2019 through December 31, 2019) and six months of forecasted data (January 1, 2020 through June 30, 2020), along with certain post-test year adjustments in accord with the Board's long-standing *Elizabethtown Water*[2] standards. JCP&L plans to file "9 + 3" and "12 + 0" updates during the course of this proceeding.

9. In its Order of Approval dated October 9, 2001 in Docket No. EM00110870 (the "GPU Merger Order"), the Board approved (with certain modifications) a Stipulation of Settlement regarding the merger of JCP&L's then parent company, GPU, Inc., and FirstEnergy Corp. ("FirstEnergy"). With respect to JCP&L's capital structure for ratemaking purposes, the GPU Merger Order provides (at p. 23, ¶16):

> JCP&L shall file, in all future base rate cases, its case using two alternative capital structures. One of the alternatives shall be a consolidated capital structure based on the capital structure that is maintained by FirstEnergy (the holding company). The second alternative shall be a stand-alone JCP&L capital structure. The parties to future base rate cases shall be free to argue for the benefits of using either capital structure for ratemaking purposes or another alternative.

The GPU Merger Order (at p. 23, ¶17) also directed that:

> JCP&L shall maintain a capital structure, dividend policy, and use its best efforts to achieve financial target ratios consistent with investment grade debt ratings as reported by Moody's Investors Service and Standard & Poor's.

JCP&L's 2020 Base Rate Filing complies with these directives.

[2] *In re Elizabethtown Water Company*, BPU Docket No. WR850433085 (Order dated May 23, 1985), at 2.

10. JCP&L's 2020 Base Rate Filing further complies with all other provisions of the Board's GPU Merger Order, more particularly including those provisions relating to the potential impact of the merger on JCP&L's rates (see Merger Order at 22-23, ¶¶12-22).

11. In an Order dated February 10, 2011 in Docket No. EM11010012 (the "Allegheny Merger Order"), the Board accepted a Stipulation ("January 18, 2011 Stipulation") relating to the proposed acquisition by FirstEnergy Corp., the parent company of JCP&L, of Allegheny Energy, Inc. The January 18, 2011 Stipulation (at ¶11) provides, among other things, that:

> If in future rate proceedings involving determinations of return on equity ("ROE") JCP&L files ROE testimony that includes a "comparables" analysis as has been the general practice in rate proceedings, JCP&L will, to the extent reasonable, include in the "comparables" group "distribution only" utilities or utilities with the majority of their assets under regulation, but may include other types of "comparables" as deemed appropriate by its expert ROE witness.

JCP&L's 2020 Base Rate Filing complies with this directive.

12. Furthermore, the Board Order approving JCP&L's Reliability Plus[3] requires that the Company file a base rate case no later than June 1, 2024. This filing satisfies that requirement.

13. Despite the increase approved as a result of the 2016 base rate case, JCP&L's residential rates (delivery and total including basic generation service ("BGS"))[4], continue to be the lowest among the State's four electric distribution companies. At the same time, the Company continues to invest in its distribution system to provide safe, adequate and reliable

[3] *I/M/O the Verified Petition of Jersey Central Power & Light Company for Approval of an Infrastructure Investment Program (JCP&L Reliability Plus),* BPU Docket No. EO18070728, Order dated May 8, 2019.

[4] "Delivery" refers to the distribution rate plus the non-bypassable rate charges and taxes; "total" refers to the delivery rate plus BGS charges.

service. Indeed, as JCP&L witnesses Dennis Pavagadhi explains in his direct testimony (Exhibit JC-7), the Company's distribution system reliability performance continues to satisfy all applicable BPU service reliability standards. The rate relief requested in this filing will allow JCP&L to continue to provide the level of electric distribution service its customers demand.

SUMMARY OF PROPOSED RATE ADJUSTMENTS

14. Based upon JCP&L's current base rates, the new rates proposed herein would result in an overall average increase in JCP&L's rates of approximately $186.9 million annually, or an overall average increase in JCP&L rates of 7.8%.

15. A typical residential customer using 766 kWh per month currently pays $102.29 per month for electricity, on average. The implementation of the requested rate adjustments would increase that typical residential monthly bill by $8.73 or 8.5%, resulting in an average monthly payment of $111.02.

OTHER PROPOSED TARIFF REVISIONS

16. JCP&L proposes to revise certain of the terms and conditions of its existing tariff for electric service, as currently set forth in its Tariff For Service, BPU No. 12 – ELECTRIC. Copies of the proposed revised tariff sheets are included as Schedule YP-5 to the Direct Testimony of Yongmei Peng (Exhibit JC-12). Explanations of the manner in which the proposed tariff revisions differ from JCP&L's existing tariff and a summary of the reasons for the proposed changes are set forth in Ms. Peng's testimony and in the Direct Testimony of Thomas R. Donadio (Exhibit JC-13).

17. In addition, JCP&L proposes certain revisions to its LED Street Lighting tariff. Mark A. Mader explains the reasons for the proposed changes in his Direct Testimony (Exhibit JC-3).

DEPRECIATION RATES

18. The Company is filing a new depreciation study and proposing modifications to its depreciation accrual rates. John J. Spanos is sponsoring the depreciation study and related Direct Testimony (Exhibit JC-14).

ROLL-IN OF JCP&L RELIABILITY PLUS INVESTEMENTS INTO BASE RATES

19. The Company is requesting that all of the capital investments under the JCP&L Reliability Plus program that will be placed into service by December 31, 2020 be rolled into base rates. Mark A. Mader provides an explanation and the justification for this proposal in his Direct Testimony (Exhibit JC-3).

RATE EFFECTIVE DATE

20. JCP&L is proposing a rate effective date of March 19, 2020, which is not less than 30 days after the filing of this Petition. JCP&L expects that the Board will follow its normal procedures for issuing the two statutory suspension orders, which would result in the Company's revised base rates becoming effective at the end of the second suspension period, in late November 2020.

PREFILED TESTIMONY, SCHEDULES AND EXHIBITS

21. Attached hereto and made a part of this Verified Petition are the following prefiled testimony, schedules and exhibits thereto:

Witness	**Exhibit No.**	**Topics**
James V. Fakult	JC-2	Overview of the Company and the Filing
Mark A. Mader	JC-3	Revenue Normalization Adjustment, Consolidated Tax Adjustment, LED Street Lighting Tariff Changes, Storm

		Expense Amortization, and JCP&L Reliability Plus
Carol A. Pittavino	JC-4	Revenue Requirements and Adjustments
Jennifer Spricigo	JC-5	Certain Revenue Adjustments
Tracy Ashton	JC-6	Pension and OPEB Expenses
Dennis Pavagadhi	JC-7	Distribution Operations, Vegetation Management, Capital Expenditures and O&M Expenses
Thomas Workoff	JC-8	Meteorological Aspects of the JCP&L Service Territory
Joseph Dipre	JC-9	Capital Structure, Embedded Cost of Debt, and Cost of Capital
Dylan M. D'Ascendis	JC-10	Return on Equity
Stephanie R. Zieger	JC-11	Cost of Service Study
Yongmei Peng	JC-12	Rate Design/Tariff Issues, Proof of Revenues/Customer Impacts
Thomas R. Donadio	JC-13	Proposed Tariff Changes
John J. Spanos	JC-14	Depreciation Study and Proposed Depreciation Accrual Rates
Olenger L. Pannell	JC-15	Service Company Charges and Allocations
James E. O'Toole	JC-16	Cash Working Capital/Lead-Lag Study

REQUEST FOR CONFIDENTIAL TREATMENT

22. The Direct Testimony of Stephanie R. Zieger (Exhibit JC-11) contains five supporting schedules. Four of these schedules contains confidential information. Accordingly, JCP&L is filing both confidential and redacted (public) versions of Ms. Zieger's testimony. The

body of Ms. Zieger's testimony contains no confidential information. The redacted version of Ms. Zieger's testimony contains redacted versions of Schedules SRZ-1, SRZ-2, SRZ-3 and SRZ-4. The Company's request for confidential treatment is fully-explained and supported in Ms. Zieger's Affidavit of Confidentiality that is being filed herewith.

PUBLIC NOTICE AND SERVICE OF FILING

23. Notice of this 2020 Base Rate Filing, including a statement of the overall effect thereof on customers of the Company, which will be combined with notice of the dates, times and places of the public hearings to be scheduled thereon, will be served by mail upon the municipal clerks, the clerks of the Boards of Chosen Freeholders and, where appropriate, the County Executive Officers of all counties and municipalities located in the Company's service territory, in accordance with the regulations of the Board as set forth in N.J.A.C. 14:1-5.12(b)1. Such notice will be duly mailed following the scheduling of the dates, times and places of the hearings thereon, as discussed below. Listings of the aforementioned public officials are contained in Appendices A-1, A-2 and A-3 which are annexed hereto. Such notice will be substantially in the form of the notice annexed hereto as Appendix A.

24. Public notice of this 2020 Base Rate Filing, including a statement of the overall effect thereof on customers of the Company, and which will be combined with notice of the dates, times and places of the public hearings to be scheduled thereon, substantially in the form of the notice set forth in Appendix A annexed hereto, will also be published in daily and weekly newspapers published and/or circulated in the Company's service areas, after the dates, times and places of all such public hearings thereon have been scheduled by the Board or by the Office of Administrative Law, in compliance with N.J.A.C. 14:1-5.12(b)3, (c) and (d).

ADDITIONAL INFORMATION

25. In compliance with N.J.A.C. 14:1-5.12, annexed hereto are the following additional information and financial statements:

Appendix B	-	Comparative Balance Sheets at December 31, 2016, 2017 & 2018[5]
Appendix C	-	Comparative Income Statements For the Calendar Years Ending December 31, 2016, 2017 & 2018
Appendix D	-	Balance Sheet at December 31, 2018
Appendix E	-	Statement of the Amount of Revenue Derived in Calendar Year 2018 From Intrastate Sales and Services at Current Rates
Appendix F	-	Pro Forma Income Statement Reflecting Operating Income at Present and Proposed Rates, With Explanation of All Adjustments Thereon and Calculation of Indicated Rates of Return on Pro Forma Rate Base. Note that the information specified in this filing requirement is provided in Schedules CAP-1 and CAP-4 to the Direct Testimony of Carol A. Pittavino (Exhibit JC-4).
Appendix G	-	Itemized Schedule of Payments or Accruals to Affiliates
Appendix H	-	Proposed Revised Tariff Sheets. Note that Appendix H is provided as Schedule YP-5 to the Direct Testimony of Yongmei Peng (Exhibit JC-12).

SERVICE OF PETITION

26. Copies of this Verified Petition and of all appendices, supporting testimony, schedules and exhibits thereto have been or will be duly served by hand delivery at the time of the filing hereof upon the Department of Law and Public Safety, Richard J. Hughes Justice Complex,

[5] The financial statements as of December 31, 2019 (for Appendices B, C, D and E) are not yet available, and will be filed with the Board as soon as they are available.

P.O. Box 080, Trenton, N.J. 08625-0080, and upon the Director, Division of Rate Counsel, 140 East Front Street, 4th Floor, P.O. Box 003, Trenton, N.J. 08625-0003, in compliance with N.J.A.C. 14:1-5.12(b)2.

CONCLUSION

WHEREFORE, the Petitioner, Jersey Central Power & Light Company, respectfully requests that the Board issue a final decision and order:

(1) approving and accepting the revised rates and charges for electric service as proposed herein, to become effective for service rendered on and after March 19, 2020;

(2) approving and accepting the attached revised tariff sheets for inclusion in JCP&L's Tariff For Service, BPU No. 13 – ELECTRIC, effective for service rendered on and after March 19, 2020; and

(3) granting such other and further relief as the Board shall deem just, lawful and proper.

Respectfully submitted,

Dated: February 18, 2020

COZEN O'CONNOR, P.C.
Attorneys for Petitioner,
Jersey Central Power & Light Company

By: Greg Eisenstark
Gregory Eisenstark

One Gateway Center
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Newark, NJ 07102
(973) 200-7411

AFFIDAVIT
OF
VERIFICATION

Mark A. Mader, being duly sworn upon his oath, deposes and says:

1. I am Director of Rates & Regulatory Affairs – New Jersey for First Energy Service Company, and I am duly authorized to make this Affidavit of Verification on behalf of Jersey Central Power & Light Company ("JCP&L"), the Petitioner named in the foregoing Verified Petition.

2. I have read the contents of the foregoing Verified Petition by JCP&L for review and approval of the proposed increases in and other adjustments to its rates and charges for electric service and for approval of other proposed tariff revisions in connection therewith, and I hereby verify that the statements of fact and other information contained therein are true and correct to the best of my knowledge, information and belief.

Mark A. Mader

Sworn to and subscribed before me
this 11th day of February 2020.

(Notary Public)

CHRISTINE R. BROWN
NOTARY PUBLIC OF NEW JERSEY
MY COMMISSION EXPIRES SEPTEMBER 11, 2020

APPENDIX A

PUBLIC NOTICE

JERSEY CENTRAL POWER & LIGHT COMPANY

NOTICE OF PROPOSED RATE INCREASES AND OTHER ADJUSTMENTS WITH RESPECT TO JCP&L'S TARIFF RATES AND CHARGES FOR ELECTRIC SERVICE, AND WITH RESPECT TO OTHER PROPOSED TARIFF CHARGES AND REVISIONS

AND

NOTICE OF PUBLIC HEARINGS THEREON

TO OUR CUSTOMERS:

On February 18, 2020, Jersey Central Power & Light Company ("JCP&L" or the "Company"), filed a Verified Petition with the New Jersey Board of Public Utilities (the "Board"), under BPU Docket No. _______________, together with supporting appendices, testimony, exhibits and schedules and revised Tariff sheets.

The Verified Petition seeks the Board's approval of proposed overall increases in and/or other adjustments to JCP&L's various Tariff rates and charges for electric service, and for approval of other proposed Tariff charges and revisions, which are proposed to become effective for service rendered on and after March 19, 2020, or at such later date as the Board may determine.

Based on the Verified Petition, the proposed new rates would yield an overall net operating revenue increase of approximately $186.9 million, representing an overall revenue increase of about 7.8% as compared to the same current annualized Tariff rates and revenues. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage.

Copies of the Verified Petitions and all related documents are available for inspection at the Company's regional headquarters at 101 Crawfords Corner Rd. Building #1, Suite 1-511, Holmdel, New Jersey 07733 and at 300 Madison Avenue, Morristown, New Jersey 07962-1911, at each of the Company's local business offices, and at the Board of Public Utilities, 44 South Clinton Avenue, 9th Floor, P.O. Box 350, Trenton, New Jersey 08625. A copy of the filing will also be posted on the Company's website at:

https://www.firstenergycorp.com/jersey_central_power_light/regulatory.html

The following comparisons of present and proposed rates will permit customers to determine the approximate net effect upon them of the proposed increases and adjustments in rates. Any assistance required by customers in this regard will be furnished by the Company upon request. Please note that the Board in its discretion may apply all or any portion of whatever rate increases the Board may ultimately allow to other rate schedules or in a different manner than what JCP&L has proposed in its filings. Accordingly, the final rates and charges to be determined by the Board in this proceeding may be different than what JCP&L has described herein.

Summary of Customer Impact

	Residential Average Bill (Includes 6.625 % Sales and Use Tax)		
	Current Monthly Bill (1)	Proposed Monthly Bill (2)	Proposed Monthly Increase
Residential (RS)			
500 kWh average monthly usage	$64.27	$69.33	$5.06
1000 kWh average monthly usage	$132.93	$143.81	$10.88
1500 kWh average monthly usage	$203.39	$220.59	$17.20
Residential Time of Day (RT)			
500 kWh average monthly usage	$72.97	$80.19	$7.22
1000 kWh average monthly usage	$140.75	$151.69	$10.94
1500 kWh average monthly usage	$208.54	$223.19	$14.65
	Overall Class Average Per Customer (Includes 6.625 % Sales and Use Tax)		
Rate Class	Current Monthly Bill (1)	Proposed Monthly Bill (2)	Proposed Monthly Increase %
Residential (RS)	$104.15	$113.39	8.9%
Residential Time of Day (RT)	$157.02	$168.81	7.5%
General Service – Secondary (GS)	$588.36	$631.92	7.4%
General Service - Secondary Time of Day (GST)	$25,375.01	$27,198.47	7.2%
General Service – Primary (GP)	$31,526.47	$33,172.66	5.2%
General Service – Transmission (GT)	$84,892.45	$88,078.27	3.8%
Lighting (Average Per Fixture)	$10.44	$11.72	12.2%
(1) Rates effective 2/1/2020			
(2) Proposed rates effective TBD			

The Company has also proposed other Tariff revisions and related charges, some of which would apply to all customers and others that would apply only to those customers whose requests or actions give rise to the related costs. Descriptions of all such proposed Tariff revisions are included in Exhibits JC-3, JC-7, JC-12 and JC-13, and their associated schedules.

Notice of these filings together with a statement of the effect thereof on customers are being served upon the clerk, executive or administrator of each municipality and county within the Company's service areas. Such notice has also been served, together with the Verified Petitions, Tariffs, rate schedules and all other exhibits, upon the Director of the Division of Rate Counsel, who will represent the interests of ratepayers in these proceedings.

PLEASE TAKE NOTICE that the New Jersey Office of Administrative Law has scheduled public hearings on the Verified Petition under OAL Docket No. _______________ at the following times and places:

Members of the public will have an opportunity to be heard and/or to submit written comments or statements at each or any of the public hearings if they wish to do so. Such written comments or statements may also be submitted directly the Clerk of the Office of Administrative Law, 33 Washington Street, Newark, NJ 07102.

Dated: _________, 2020 **JERSEY CENTRAL POWER & LIGHT COMPANY**

List of Municipal Clerks

Clerk, Township of Aberdeen
1 Aberdeen Square
Aberdeen, NJ 07747

Clerk, Township of Alexandria
242 Little York-Mt. Pleasant Rd.
Milford, NJ 08848

Clerk, Township of Allamuchy
292 Alphano Rd.
PO Box A
Allamuchy, NJ 07820

Clerk, Borough of Allenhurst
125 Corlies Avenue
Allenhurst, NJ 07711

Clerk, Borough of Alpha
1001 E. Boulevard
Alpha, NJ 08865

Clerk, Borough of Andover
137 Main Street
Andover, NJ 07821

Clerk, Andover Township
134 Newton-Sparta Road
Newton, NJ 07860-2746

Clerk, City of Asbury Park
One Municipal Plaza Asbury
Park, NJ 07712

Clerk, Borough of Atlantic Highlands
Municipal Building
100 First Avenue
Atlantic Highlands, NJ 07716

Clerk, Borough of Avon By The Sea
Municipal Building
301 Main Street
Avon By The Sea, NJ 07717

Clerk, Township of Barnegat
900 W. Bay Avenue
Barnegat, NJ 08805-1298

Clerk, Borough of Bay Head
81 Bridge Avenue
PO Box 248
Bay Head, NJ 08742

Clerk, Borough of Beachwood
1600 Pinewald Rd.
Beachwood, NJ 08722

Clerk, Bedminster Township
One Miller Lane
Bedminster, NJ 07921

Clerk, Borough of Belmar
601 Main Street
PO Box A
Belmar, NJ 07719-0070

Clerk, Town of Belvidere
691 Water Street
Belvidere, NJ 07823

Clerk, Township of Berkeley
627 Pinewald–Kenswick Rd.
PO Box B
Bayville, NJ 08721-0287

Clerk, Township of Berkeley Heights
29 Park Avenue
Berkeley Heights, NJ 07922-1499

Clerk, Bernards Township
1 Collyer Lane
Basking Ridge, NJ 07920-1441

Clerk, Borough of Bernardsville
Borough Hall - 166 Mine Brook Road
PO Box 158
Bernardsville, NJ 07924-0158

Clerk, Township of Bethlehem
405 Mine Road
Asbury, NJ 08802-1107

Clerk, Township of Blairstown
106 Route 94
Blairstown, NJ 07825

Clerk, Borough of Bloomingdale
Municipal Building
101 Hamburg Turnpike
Bloomingdale, NJ 07403

Clerk, Borough of Bloomsbury
91 Brunswick Avenue
Bloomsbury, NJ 08804-0098

Clerk, Town of Boonton
100 Washington Street
Boonton, NJ 07005

Clerk, Township of Boonton
155 Powerville Road
Boonton, NJ 07005-8729

Clerk, Borough of Bradley Beach
701 Main Street
Bradley Beach, NJ 07720

Clerk, Township of Branchburg
1077 US Highway 202 N.
Somerville, NJ 08876-3936

Clerk, Borough of Branchville
34 Wantage Avenue
Branchville, NJ 07826-0840

Clerk, Borough of Brielle
601 Union Lane - PO Box 445
Brielle, NJ 08730-0445

List of Municipal Clerks

**Clerk, Brick Township
401 Chambersbridge Road
Brick Town, NJ 08723**

**Clerk, Township of Bridgewater
100 Commons Way
Bridgewater, NJ 08807**

**Clerk, Borough of Butler
1 Ace Road
Butler, NJ 07405**

**Clerk, Township of Byram
10 Mansfield Drive
Stanhope, NJ 07874**

**Clerk, Borough of Califon
39 Academy Street
PO Box 368
Califon, NJ 07830-0368**

**Clerk, Borough of Chatham
Municipal Building
54 Fairmount Avenue
Chatham, NJ 07928-2393**

**Clerk, Township of Chatham
58 Meyersville Road
Chatham, NJ 07928**

**Clerk, Borough of Chester
Municipal Building
PO Box 487
50 North Road
Chester, NJ 07930**

**Clerk, Township of Chester
Municipal Building
1 Parker Road
Chester, NJ 07930**

**Clerk, Township of Chesterfield
Municipal Building
300 Bordentown-Chesterfield Road
Chesterfield, NJ 08515**

**Clerk, Town of Clinton
43 Leigh Street
Clinton, NJ 08809**

**Clerk, Township of Clinton
1370 Rte. 31 North
Annandale, NJ 08801**

**Clerk, Township of Colts Neck
Town Hall
124 Cedar Drive
Colts Neck, NJ 07722-0249**

**Clerk, Township of Cranbury
23A North Main Street
Cranbury, NJ 08512-3287**

**Clerk, Borough of Deal
Municipal Building
P.O. Box 56 - Durant Square
Deal, NJ 07723-0056**

**Clerk, Township of Denville
Municipal Building
1 St. Mary's Place
Denville, NJ 07834**

**Clerk, Township of Delaware
Township Hall
PO Box 500
Sergeantsville, NJ 08557**

**Clerk, Town of Dover
Town Hall
37 North Sussex Street
Dover, NJ 07801**

**Clerk, Township of Dover
33 Washington Street
PO Box 728
Toms River, NJ 08754-0728**

**Clerk, Township of East Amwell
1070 Rtes. 202 and 31
Ringoes, NJ 08551-1051**

**Clerk, Township of East Brunswick
1 Jean Walling Civic Center
PO Box 1081
East Brunswick, NJ 08816-1081**

**Clerk, Township of East Hanover
411 Ridgedale Avenue
East Hanover, NJ 07936**

**Clerk, Township of East Windsor
Municipal Building
16 Lanning Boulevard
East Windsor, NJ 08520-1999**

**Clerk, Borough of Eatontown
Borough Hall
47 Broad Street
Eatontown, NJ 07724-1698**

**Clerk, Borough of Englishtown
15 Main Street
Englishtown, NJ 07726**

**Clerk, Borough of Fair Haven
Municipal Building
748 River Road
Fair Haven, NJ 07704**

**Clerk, Borough of Far Hills
6 Prospect Street
Far Hills, NJ 07931**

**Clerk, Borough of Farmingdale
Municipal Building
11 Asbury Avenue
Farmingdale, NJ 07727**

**Clerk, Borough of Flemington
38 Park Avenue
Flemington, NJ 08822-1398**

**Clerk, Borough of Florham Park
Borough Hall
111 Ridgedale Avenue
Florham Park, NJ 07932**

List of Municipal Clerks

Clerk, Township of Frankford
151 US Highway 206
Augusta, NJ 07822

Clerk, Borough of Franklin
46 Main Street
Franklin, NJ 07416

Clerk, Township of Franklin
475 DeMott Lane
Somerset, NJ 08873

Clerk, Township of Franklin
Municipal Building
2093 Rte. 57
PO Box 547
Broadway, NJ 08808

Clerk, Township of Fredon
443 Rte. 94
Newton, NJ 07860

Clerk, Borough of Freehold
51 West Main Street
Freehold, NJ 07728-2195

Clerk, Township of Freehold
One Municipal Plaza
Freehold, NJ 07728-3099

Clerk, Township of Frelinghuysen
210 Main Street
Johnsonburg, NJ 07825

Clerk, Borough of Frenchtown
Borough Hall
29 Second Street
Frenchtown, NJ 08825

Clerk, Borough of Glen Gardner
PO Box 307
Glen Gardner, NJ 08826

Clerk, Township of Green
150 Kennedy Road
PO Box 65
Tranquility, NJ 07879

Clerk, Township of Green Brook
111 Greenbrook Road
Greenbrook, NJ 08812-2501

Clerk, Township of Greenwich
321 Greenwich Street
Stewartsville, NJ 08886

Clerk, Town of Hackettstown
215 Stiger Street
Hackettstown, NJ 07840

Clerk, Borough of Hamburg
Municipal Building
16 Wallkill Avenue
Hamburg, NJ 07419

Clerk, Borough of Hampton
PO Box 418
Hampton, NJ 08827

Clerk, Township of Hampton
1 Rumsey Way
Hampton Twp., Newton, NJ 07860

Clerk, Township of Hanover
Municipal Building
1000 Rte. 10 - PO Box 250
Whippany, NJ 07981-0250

Clerk, Township of Harding
Harding Township Municipal Offices
PO Box 666
New Vernon, NJ 07976

Clerk, Township of Hardwick
40 Spring Valley Road
Blairstown, NJ 07825

Clerk, Township of Hardyston
Municipal Building, Suite A
149 Wheatsworth Rd.
Hamburg, NJ 07419

Clerk, Township of Harmony
3003 Belvidere Road
Phillipsburg, NJ 08865

Clerk, Township of Hazlet
1766 Union Avenue
Hazlet, NJ 07730

Clerk, Borough of Helmetta
Borough Hall
51 Main Street
Helmetta, NJ 08828

Clerk, Borough of High Bridge
71 Main Street
High Bridge, NJ 08829-1003

Clerk, Borough of Highlands
42 Shore Drive
Highlands, NBJ 07732-1699

Clerk, Borough of Hightstown
156 Bank Street
Hightstown, NJ 08520-3291

Clerk, Township of Hillsborough
379 S. Branch Road
Hillsborough, NJ 08844

Clerk, Township of Holland
61 Church Road
Milford, NJ 08848

Clerk, Township of Holmdel
4 Crawford's Corner Road
PO Box 410
Holmdel, NJ 07733-0410

List of Municipal Clerks

Clerk, Borough of Hopatcong
Municipal Building
111 River Styx Road
Hopatcong, NJ 07843-1599

Clerk, Township of Hope
PO Box 284
407 Hope-Great Meadows Rd
Hope, NJ 07844

Clerk, Township of Hopewell
Municipal Building
201 Washington Crossing Pennington Rd
Titusville, NJ 08560

Clerk, Township of Howell
PO Box 580
4567 Route 9 North
Howell, NJ 07731-0580

Clerk, Township of Independence
Municipal Building
286 Rte. 46 West, PO Box 164
Great Meadows, NJ 07838

Clerk, Borough of Interlaken
Borough Hall
100 Gasmere Avenue
Interlaken, NJ 07712

Clerk, Borough of Island Heights
Municipal Complex
East End & Van Sant Ave.
Island Heights, NJ 08732

Clerk, Township of Jackson
Municipal Building
95 West Veterans Highway
Jackson, NJ 08527

Clerk, Borough of Jamesburg
131 Perrineville Road
Jamesburg, NJ 08831

Clerk, Township of Jefferson
Municipal Building
1033 Weldon Road
Lake Hopatcong, NJ 07849

Clerk, Borough of Keansburg
Municipal Building
29 Church Street
Keansburg, NJ 07734

Clerk, Borough of Keyport
70 West Front Street
Keyport, NJ 07735-0070

Clerk, Township of Kingwood
599 Oak Grove Road & Route 519
Frenchtown, NJ 08825

Clerk, Borough of Kinnelon
Municipal Building
130 Kinnelon Road
Kinnelon, NJ 07405

Clerk, Township of Knowlton
Municipal Building
628 Rote. 94
Columbia, NJ 07832

Clerk, Township of Lacey
Municipal Building
818 W. Lacey Road
Forked River, NJ 08731

Clerk, Township of Lafayette
33 Morris Farm Road
Lafayette, NJ 07848

Clerk, Borough of Lakehurst
5 Union Avenue
Lakehurst, NJ 08733-3097

Clerk, Township of Lakewood
Municipal Building
231 Third Street
Lakewood, NJ 08701-3220

Clerk, City of Lambertville
18 York Street
Lambertville, NJ 08530

Clerk, Borough of Lavallette
1306 Grand Central Ave.
Lavallette, NJ 08735

Clerk, Borough of Lebanon
6 High Street
Lebanon, NJ 08833

Clerk, Township of Lebanon
530 W. Hill Road
Glen Gardner, NJ 08826-9714

Clerk, Township of Liberty
349 Mtn. Lake Road
Great Meadows, NJ 07838

Clerk, Borough of Lincoln Park
Municipal Building
34 Chapel Hill Road
Lincoln Park, NJ 07035-1998

Clerk, Borough of Little Silver
Borough Hall
480 Prospect Avenue
Little Silver, NJ 07739

Clerk, Township of Livingston
357 S. Livingston Avenue
Livingston, NJ 07039-3994

Clerk, Village of Loch Arbour
550 Main Street
Loch Arbour, NJ 07711

Clerk, City of Long Branch
City Hall
344 Broadway
Long Branch, NJ 07740

Clerk, Township of Lopatcong
Municipal Building
232 South Third St. - Morris Park
Phillipsburg, NJ 08865-1898

List of Municipal Clerks

Clerk, Borough of Madison
Hartley Dodge Memorial Building
50 Kings Road
Madison, NJ 07940-2592

Clerk, Township of Manalapan
120 Route 522 & Taylor-Mills Road
Manalapan Township, NJ 07726

Clerk, Borough of Manasquan
201 E. Main Street
Manasquan, NJ 08736

Clerk, Township of Manchester
1 Colonial Drive
Manchester Township, NJ 08759

Clerk, Township of Mansfield
3135 Route 206 South – Suite 1
Columbus, NJ 08022-0249

Clerk, Borough of Mantoloking
Borough Hall
PO Box 4391
Brick, NJ 08738

Clerk, Township of Maplewood
Municipal Building
574 Valley Street
Maplewood, NJ 07940-0690

Clerk, Township of Marlboro
Municipal Complex
1979 Township Drive
Marlboro, NJ 07746

Clerk, Borough of Matawan
201 Broad Street
Matawan, NJ 07747

Clerk, Borough of Mendham
2 W. Main Street
Mendham, NJ 07945

Clerk, Township of Middletown
Municipal Building
1 Kings Highway
Middletown, NJ 07748-2594

Clerk, Borough of Milford
30 Water Street
PO Box 507
Milford, NJ 08848-0507

Clerk, Township of Millburn
Town Hall
375 Millburn Avenue
Millburn, NJ 07041-1379

Clerk, Township of Millstone
Municipal Building
470 Stage Coach Road
Clarksburg, NJ 08510

Clerk, Township of Mine Hill
Municipal Building
10 Baker Street
Mine Hill, NJ 07803

Clerk, Borough of Monmouth Beach
22 Beach Road
Monmouth Beach, NJ 07750

Clerk, Monroe Township
Municipal Complex
1 Municipal Plaza
Monroe Township, NJ 08831-1900

Clerk, Township of Montague
277 Clove Road
Montague, NJ 07827

Clerk, Borough of Netcong
Municipal Building
23 Maple Avenue
Netcong, NJ 07857-1121

Clerk, Township of New Hanover
2 Hockamick Rd.
Cookstown, NJ 08511

Clerk, Borough of New Providence
360 Elkwood Avenue
New Providence, NJ 07974-1844

Clerk, Town of Newton
39 Trinity Street
Newton, NJ 07860

Clerk, Township of North Hanover
Municipal Building
41 Schoolhouse Road
Jacobstown, NJ 08562

Clerk, Township of Ocean
Township Hall
399 Monmouth Road
Oakhurst, NJ 07755-1589

Clerk, Township of Ocean
50 Railroad Avenue
Waretown, NJ 08758

Clerk, Borough of Ocean Gate
801 Ocean Gate Avenue, CN-100
Ocean Gate, NJ 08740

Clerk, Borough of Oceanport
315 East Main Street
Oceanport, NJ 07757

Clerk, Borough of Ogdensburg
14 Highland Avenue
Ogdensburg, NJ 07439

Clerk, Township of Montville
Municipal Building
195 Changebridge Road
Montville, NJ 07045-9498

Clerk, Township of Morris
50 Woodland Avenue
PO Box 7603
Convent Station, NJ 07961-7603

List of Municipal Clerks

Clerk, Borough of Morris Plains
531 Speedwell Avenue
Morris Plains, NJ 07950

Clerk, Town of Morristown
200 South Street, CN-914
Morristown, NJ 07963-0914

Clerk, Borough of Mt. Arlington
419 Howard Blvd.
Mt. Arlington, NJ 07856-1129

Clerk, Township of Mount Olive
Municipal Building
204 Flanders-Drakestown Road
PO Box 450
Budd Lake, NJ 07828

Clerk, Borough of Mountain Lakes
400 Boulevard
Mountain Lakes, NJ 07046

Clerk, Borough of Mountainside
Municipal Building
1385 Route 22
Mountainside, NJ 07092

Clerk, Township of Neptune
25 Neptune Blvd – PO Box 1125
Neptune, NJ 07753-1125

Clerk, Borough of Neptune City
106 W. Sylvania Avenue
Neptune City, NJ 07753

Clerk, Township of Old Bridge
One Old Bridge Plaza
Old Bridge, NJ 08857

Clerk, Township of Oxford
Municipal Building
11 Green Street, PO Box 119
Oxford, NJJ 07863

Clerk, Township of Parsippany-Troy Hills
1001 Parsippany Boulevard
Parsippany, NJ 07054

Clerk, Township of Long Hill
915 Valley Road
Long Hill, NJ 07933

Clerk, Boroughs of Peapack & Gladstone
1 School Street, PO Box 218
Peapack, NJ 07977

Clerk, Borough of Pemberton
Municipal Building
50 Egbert Street
Pemberton, NJ 08068-0261

Clerk, Township of Pemberton
500 Pemberton-Browns Mills Road
Pemberton, NJ 08068-1539

Clerk, Township of Pequannock
530 Newark-Pompton Turnpike
Pompton Plains, NJ 07444

Clerk, Town of Phillipsburg
Municipal Building
120 Filmore Street
Phillipsburg, NJ 08865

Clerk, Borough of Pine Beach
599 Pennsylvania Avenue
PO Box 425
Pine Beach, NJ 08741-0425

Clerk, Township of Plumsted
121 Evergeen Road
New Egypt, NJ 08533

Clerk, Township of Pohatcong
50 Municipal Drive
Phillipsburg, NJ 08865

Clerk, Borough of Point Pleasant
2233 Bridge Avenue - PO Box 25
Point Pleasant, NJ 08742

Clerk, Borough of Pt. Pleasant Beach
416 New Jersey Avenue
Pt. Pleasant Beach, NJ 08742

Clerk, Borough of Pompton Lakes
Municipal Building – 25 Lenox Avenue
Pompton Lake, NJ 07442

Clerk, Borough of Raritan
22 First Street
Raritan, NJ 08869

Clerk, Township of Raritan
One Municipal Drive
Flemington, NJ 08822-3446

Clerk, Township of Randolph
Municipal Building
502 Millbrook Avenue
Randolph, NJ 07869

Clerk, Borough of Ringwood
Borough Hall
60 Margaret King Avenue
Ringwood, NJ 07456

Clerk, Borough of Riverdale
91 Newark Pompton Turnpike
Riverdale, NJ 07457

Clerk, Township of Readington
Municipal Building
509 Rte. 523
Whitehouse Station, NJ 08889

Clerk, Borough of Red Bank
90 Monmouth Street
Red Bank, NJ 07701

List of Municipal Clerks

Clerk, Borough of Rockaway
Municipal Building
1 East Main Street
Rockaway, NJ 07866

Clerk, Township of Rockaway
65 Mt. Hope Road
Rockaway, NJ 07866-1698

Clerk, Borough of Roosevelt
Borough Hall - 33 N. Richdale Avenue
PO Box 128
Roosevelt, NJ 08555-0128

Clerk, Township of Roxbury
1715 Rte. 46
Ledgewood, NJ 07852

Clerk, Borough of Rumson
Memorial Borough Hall
80 E. River Rd.
Rumson, NJ 07760

Clerk, Sandyston Township
133 Route 645
Branchville, NJ 07826

Clerk, Borough of Sayreville
167 Main Street
Sayreville, NJ 08872

Clerk, Borough of Sea Bright
1167 Ocean Avenue
Sea Bright, NJ 07760

Clerk, Borough of Sea Girt
321 Baltimore Blvd. PO Box 296
Sea Girt, NJ 08750

Clerk, Seaside Heights Borough
901 Boulevard
Seaside Heights, NJ 08751

Clerk, Borough of Seaside Park
1701 N. Ocean Avenue
PO Box B
Seaside Park, NJ 08752

Clerk, Borough of Shrewsbury
419 Sycamore Avenue
PO Box 7420
Shrewsbury, NJ 07702-7420

Clerk, Township of Shrewsbury
1979 Crawford Street
Shrewsbury, NJ 07724

Clerk, City of South Amboy City
Hall, 140 N. Broadway Street
South Amboy, NJ 08879-1647

Clerk, Township of Southampton
Town Hall
5 Retreat Road
Southampton, NJ 08088

Clerk , Borough of South Belmar
1740 Main Street
PO Box 569
Lake Como, NJ 07719-0569

Clerk, Borough of South Toms River
Borough Hall
19 Double Trouble Road
South Toms River, NJ 08757

Clerk, Township of Mendham
Township Hall - W. Main & Cherry Lane
PO Box 520
Brookside, NJ 07926

Clerk, Township of South Brunswick
Municipal Complex - 540 Ridge Road
PO Box 190
Monmouth Junction, NJ 08852-0190

Clerk, Borough of Spring Lake
423 Warren Avenue
P.O. Box 638
Spring Lake, NJ 07762-0638

Clerk, Township of Sparta
65 Main Street
Sparta, NJ 07871

Clerk, Borough of Spotswood
77 Summerhill Road
Spotswood, NJ 08884

Clerk, Township of Springfield
Municipal Building – 1st Floor
100 Mountain Avenue
Springfield, NJ 07081-1702

Clerk, Borough of Spring Lake Heights
555 Brighton Avenue
Spring Lake Heights, NJ 07762

Clerk, Township of Springfield
Municipal Building
2159 Jacksonville Road
PO Box 119
Jobstown, NJ 08041

Clerk, Borough of Stockton
Municipal Building
2 South Main Street,
PO Box M
Stockton, NJ 08559

Clerk, Borough of Stanhope
77 Main Street
Stanhope, NJ 07874

Clerk, Township of Stillwater
964 Stillwater Road
Newton, NJ 07860

Clerk, Township of Tewksbury
169 County Road 517
Califon, NJ 07830

Clerk, City of Summit
512 Springfield Avenue
Summit, NJ 07901-2667

List of Municipal Clerks

Clerk, Borough of Sussex
2 Main Street
Sussex, NJ 07461-2397

Clerk, Borough of Union Beach
Municipal Building
650 Poole Avenue
Union Beach, NJ 07735

Clerk, Borough of Tinton Falls
Municipal Building
556 Tinton Avenue
Tinton Falls, NJ 07724-3298

Clerk, Township of Union
140 Perryville Road
Hampton, NJ 08827

Clerk, Borough of Victory Gardens
Municipal Building
337 S. Salem Street
Dover, NJ 07801

Clerk, Township of Upper Freehold
Municipal Building
314 County Rte. 539
Cream Ridge, NJ 08514

Clerk, Township of Vernon
Municipal Building
21 Church Street
PO Box 340
Vernon, NJ 07462

Clerk, Borough of Wanaque
579 Ringwood Avenue
Wanaque, NJ 07465

Clerk, Township of Wall
2700 Allaire Road
PO Box 1168
Wall, NJ 07719-1168

Clerk, Township of Walpack
16 Old Mine Road
Walpack, NJ 07881

Clerk, Borough of Washington
100 Belvidere Avenue
Washington, NJ 07882-1426

Clerk, Township of Wantage
Municipal Building
888 Rte. 23
Sussex, NJ 07461

Clerk, Township of Warren
Municipal Building
46 Mountain Blvd.
Warren, NJ 07059-5605

Clerk, Township of Washington
Robbinsville Municipal Building
1 Washington Blvd. – 2nd Floor – Suite 6
Robbinsville, NJ 08691-1103

Clerk, Township of Washington
211 Rt. 31 North
Washington, NJ 07882

Clerk, Township of Washington
43 Schooley's Mountain Road
Long Valley, NJ 07853

Clerk, Township of West Amwell
150 Rocktown-Lambertville Rd.
Lambertville, NJ 08530-3203

Clerk, Borough of Watchung
Municipal Building
15 Mountain Blvd.
Watchung, NJ 07069-6399

Clerk, Township of Wayne
475 Valley Road
Wayne, NJ 07470

Clerk, Township of West Windsor
Municipal Building
271 Clarkville Rd., PO Box 38
West Windsor, NJ 08550

Clerk, Borough of West Long Branch
965 Broadway
West Long Branch, NJ 07764

Clerk, Township of West Milford
1480 Union Valley Road
West Milford, NJ 07840-1303

Clerk, Township of Woodland
Municipal Building
3943 County Road 563
PO Box 388
Chatsworth, NJ 08019

Clerk, Borough of Wharton
Municipal Building
10 Robert Street
Wharton, NJ 07885

Clerk, Township of White
555 County Road 519
Belvidere, NJ 07823

Clerk, Borough of Wrightstown
Borough Hall
21 Saylors Pond Road
Wrightstown, NJ 08562

Clerk, Borough of Lake Como
1740 Main Street
Lake Como, NJ 07719

List of County Freeholders

Burlington County Bd of Freeholders
County Office Bldg.
49 Rancocas Rd.
PO Box 6000
Mt. Holly, NJ 08060

Essex County Bd of Freeholders
Hall of Records
465 Dr. Martin Luther King, Jr. Blvd.
Newark, NJ 07102

Hunterdon County Bd of Freeholders
County Administration Bldg.
71 Main St.
Flemington, NJ 08822

Mercer County Bd of Freeholders
McDade Administration
640 S. Broad St.
PO Box 8068
Trenton, NJ 08650-0068

Middlesex County Bd of Freeholders
Administration Bldg.
JFK Square
PO Box 871
New Brunswick, NJ 08903

Monmouth County Bd of Freeholders
Hall of Records
One E. Main Street
Freehold, NJ 07728

Morris County Bd of Freeholders
Administration & Records Bldg.
Court St.
PO Box 900
Morristown, NJ 07963-0900

Ocean County Bd of Freeholders
Administration Bldg.
101 Hooper Ave.
PO Box 2191
Toms River, NJ 08754

Passaic County Bd of Freeholders
Administration Bldg.
401 Grand St., 2nd Flr., #223
Paterson, NJ 07505

Somerset County Bd of Freeholders
20 Grove St.
PO Box 3000
Somerville, NJ 08876

Sussex County Bd of Freeholders
Administrative Center
One Spring St.
Newton, NJ 07860

Union County Bd of Freeholders
Administration Bldg.
6th Floor
Elizabeth, NJ 07207

Warren County Bd of Freeholders
Dumont Administration Building
165 Rte. 519 S.
Belvidere, NJ 07823

List of County Executive Offices & Administrators

Burlington County Administrator
Municipal Bldg.
851 Old York Rd.
PO Box 340
Burlington, NJ 08016-0340

Burlington County Administrator
City Hall
525 High Street
Burlington, NJ 08016

Essex County Executive
Hall of Records
465 Dr. Martin Luther King, Jr. Blvd.
Newark, NJ 07102

Hunterdon County Administrator
County Administration Bldg.
71 Main St.
Flemington, NJ 08822

Mercer County Executive
McDade Administration
640 S. Broad St.
PO Box 8068
Trenton, NJ 08650-0068

Middlesex County Administrator
Administration Bldg.
JFK Square
PO Box 871
New Brunswick, NJ 08903

Monmouth County Administrator
Hall of Records
One E. Main Street
Freehold, NJ 07728

Morris County Administrator
Administration & Records Bldg.
Court St.
PO Box 900
Morristown, NJ 07963-0900

Ocean County Administrator
Administration Bldg.
101 Hooper Ave.
PO Box 2191
Toms River, NJ 08754

Passaic County Administrator
Administration Bldg.
401 Grand St.
317 Pennsylvania Avenue
Paterson, NJ 07505

Somerset County Administrator
20 Grove St.
PO Box 3000
Somerville, NJ 08876

Sussex County Administrator
Administrative Center
One Spring St.
Newton, NJ 07860

Union County Administrator
Administration Bldg.
6th Floor
Elizabeth, NJ 07207

Warren County Administrator
Dumont Administration Building
165 Rte. 519 S.
Belvidere, NJ 07823

JERSEY CENTRAL POWER & LIGHT COMPANY

Comparative Balance Sheet at
December 31, 2016, 2017 and 2018
ASSETS AND OTHER DEBITS

FERC Account		DECEMBER 31 2016	2017	2018
	UTILITY PLANT			
101-106	Utility plant	6,254,369,298	6,487,200,762	6,841,472,584
107	Construction Work in Progress	240,898,740	187,195,788	182,155,357
	Total Utility Plant	6,495,268,038	6,674,396,550	7,023,627,941
108,111	Less Accumulated Provision for Depreciation	2,025,283,279	2,020,679,040	2,148,322,401
	Net Utility Plant	4,469,984,759	4,653,717,510	4,875,305,540
120.1 - 120.4 and 120.6	Nuclear Fuel			
120.5	Accum. Provision for Amortization			
	Net Nuclear Fuel			
	Net Utility Plant	4,469,984,759	4,653,717,510	4,875,305,540
	OTHER PROPERTY AND INVESTMENTS			
121	Nonutility Property	16,979,653	16,979,653	16,979,653
122	(Less) Accum. Prov. For Deprec. And Amort.	15,896,784	15,826,573	15,829,051
123	Investment in Associated Companies	-	-	-
123.1	Investment in Subsidiary Companies	2,478,650	899,110	897,102
124	Other Investments	2,403	1,809	1,791
128	Special Funds	225,695,731	238,470,050	229,140,287
175	Long-Term Portion of Derivative Assets	216,463	96,832	43,797
	Total Other Property and Investments	229,476,116	240,620,881	231,233,579
	CURRENT AND ACCRUED ASSETS			
131	Cash			
132-134	Special Deposits	245,135,599	251,203,661	255,897,586
135	Working Funds	925	1,025	1,025
136	Temporary Cash Investments	-	-	-
142	Customer Accounts Receivable	140,196,387	140,004,701	138,064,097
143	Other Accounts Receivable	16,933,379	24,235,954	34,248,612
144	(Less) Accum. Prov. For Uncollectible Accounts-Credit	5,068,255	4,516,190	4,436,362
145	Notes Receivable from Associated Companies	-	76,019,310	-
146	Accts. Receivable from Associated Companies	61,387,897	25,426,370	62,710,890
151	Fuel Stock	-	-	-
154	Plant Materials and Operating Supplies	-	-	-
165	Prepayments	24,442,408	24,718,681	26,386,710
171	Interest and Dividend Receivable	-	-	-
172	Rents Receivable	4,402,588	3,776,239	4,785,226
173	Accrued Utility Revenues	91,689,320	81,353,005	86,376,550
174	Miscellaneous Current and Accrued Assets	-	-	-
175	Derivative Instruments Assets	-	-	-
175	(Less) Long Term Portion of Derivative Instrument Assets	-	-	-
	Total Current and Accrued Assets	579,120,248	622,222,756	604,034,334
	DEFERRED DEBITS			
181	Unamortized Debt Expenses	7,080,051	6,058,777	5,101,815
182.1	Extraordinary Property Losses	-	-	-
182.2	Unrecovered Plant and Regulatory Study Costs	4,343,911	4,234,903	4,125,895
182.3	Other Regulatory Assets	604,926,614	495,789,462	779,264,940
183	Prelim. Survey and Investigation Charges	2,193,464	2,150,583	2,328,212
184	Clearing Accounts	15,233	92,064	149,166
185	Temporary Facilities	375,454	407,128	520,035
186	Miscellaneous Deferred Debits	1,819,953,786	1,815,631,330	1,814,479,673
188	Research, Devel. And Demonstration Expend.	46,595	48,170	41,466
189	Unamortized Loss on Reacquired Debt	9,408,994	7,390,722	5,593,655
190	Accumulated Deferred Income Taxes	1,069,475,269	1,024,928,555	952,319,382
	Total Deferred Debits	3,517,819,371	3,356,731,694	3,563,924,239
	TOTAL ASSETS	8,796,400,494	8,873,292,841	9,274,497,692

JERSEY CENTRAL POWER & LIGHT COMPANY

Comparative Balance Sheet at
December 31, 2016, 2017 and 2018
LIABILITIES AND OTHER CREDITS

FERC Account		2016	DECEMBER 31 2017	2018
	PROPRIETARY CAPITAL			
201	Common Stock Issued	136,284,470	136,284,470	136,284,470
204	Preferred Stock Issued	-	-	-
207	Premium on Capital Stock	2,264,436,485	2,511,652,419	2,665,143,711
208-211	Other Paid-In Capital	36,620,746	40,953,128	46,295,786
215, 215.1,216	Retained Earnings	386,904,146	501,961,546	671,510,121
216.1	Unappropriated Undistributed Subsidiary Earnings	(34,350)	(36,428)	(38,436)
219	Accumulated Other Comprehensive Income	(1,885,396)	(2,044,696)	(5,575,366)
	Total Proprietary Capital	2,822,326,101	3,188,770,439	3,513,620,286
	LONG-TERM DEBT			
221	Bonds			
223	Advances From Associated Companies			
224	Other Long-Term Debt	1,950,000,000	1,700,000,000	1,550,000,000
225	Unamortized Premium on Long-Term Debt	-	-	-
226	(Less) Unamortized Discount on Long-Term Debt	6,058,333	5,356,305	4,799,265
	Total Long-Term Debt	1,943,941,667	1,694,643,695	1,545,200,735
	OTHER NON-CURRENT LIABILITIES			
227	Obligations Under Capital Leases	-	8,053,404	7,687,074
228.2	Accumulated Provision for Injuries and Damages	5,731,186	5,286,625	4,773,214
228.3	Accumulated Provision for Pension and Benefits	424,422,374	445,815,952	227,999,377
	Long-Term Portion of Derivative Instrument Liabilities	62,711	-	-
230	Asset Retirement Obligation	117,005,918	124,452,131	172,830,642
	Total Noncurrent Liabilities	547,222,189	583,608,112	413,290,307
	CURRENT AND ACCRUED LIABILITIES			
231	Notes Payable	-	-	-
232	Accounts Payable	121,600,128	124,138,487	181,139,989
233	Notes Payable to Associated Companies	98,434,304	-	143,086,743
234	Accounts Payable to Associated Companies	11,713,355	3,709,730	4,958,531
235	Customer Deposits	39,457,329	45,850,825	46,891,725
236	Taxes Accrued	938,279	20,293,169	3,729,369
237	Interest Accrued	24,635,155	23,488,664	23,213,454
238	Dividends Declared	-	-	-
241	Tax Collections Payable	8,599,456	1,298,608	8,838,256
242	Misc Current and Accrued Liabilities	60,761,500	67,343,151	59,283,167
243	Obligations Under Capital Leases	-	334,345	392,405
244	Derivative Instrument Liabilities	62,711	-	-
	(Less) Long-Term Portion of Derivative Instruments-Hedges	62,711	-	-
	Total Current and Accrued Liabilities	366,139,506	286,456,979	471,533,639
	DEFERRED CREDITS			
252	Customer Advances for Construction	31,732,018	35,427,361	38,217,911
255	Accumulated Deferred Investment Tax Credits	2,048,546	1,917,347	1,786,148
253	Other Deferred Credits	519,360,639	529,427,454	557,458,644
254	Other Regulatory Liabilities	392,604,926	956,536,886	1,090,926,449
257	Unamortized Gain on Reacquired Debit	77,649	57,934	38,217
282	Accum. Deferred Income Taxes-Other Property	1,465,206,510	1,015,488,312	1,061,347,417
283	Accum. Deferred Income Taxes-Other	705,740,743	580,958,322	581,077,939
	Total Deferred Credits	3,116,771,031	3,119,813,616	3,330,852,725
	TOTAL LIABILITIES AND OTHER CREDITS	8,796,400,494	8,873,292,841	9,274,497,692

APPENDIX C

JERSEY CENTRAL POWER & LIGHT COMPANY
Comparative Income Statement
For the Years 2016, 2017 and 2018

FERC Account		DECEMBER 31 2016	2017	2018
	UTILITY OPERATING INCOME			
400	Operating Revenues	1,787,393,483	1,801,101,333	1,841,851,146
	Operating Expenses:			
401	Operation Expenses	1,235,169,358	1,139,152,514	1,167,145,472
402	Maintenance Expenses	87,805,896	87,916,073	241,399,996
403	Depreciation Expenses	137,516,402	143,382,168	176,483,809
	Depreciation Expenses for Asset Retirement Costs (403.1)	(2,901)	-	111,397
404-405	Amortization and Depl. Of Utility Plant	5,530,799	6,145,923	7,070,460
406	Amortization of Utility Plant Acq. Adjustment	-	-	-
407.3	Regulatory Debits	125,704,418	142,746,615	143,485,033
407.4	(Less) Regulatory Credits	51,780,457	34,145,524	250,587,370
408.1	Taxes Other Than Income Taxes	10,405,559	11,025,411	11,748,308
409.1	Income Taxes Federal	28,317,249	79,491,408	(55,417,639)
409.1	Other	(75,817)	1,948,427	(563,717)
410.1	Provision for Deferred Income Taxes	748,568,317	792,991,357	693,756,037
411.1	(Less) Provision for Deferred Income Taxes-Cr	730,807,624	796,402,219	570,415,918
411.4	Investment Tax Credit Adj.- Net	(131,199)	(131,199)	(131,199)
411.1	Accretion Expense			8,015,272
	Total Utility Operating Expenses	1,596,220,000	1,574,120,954	1,572,099,941
	NET UTILITY OPERATING INCOME	191,173,483	226,980,379	269,751,205
	OTHER INCOME AND DEDUCTIONS			
	Other Income:			
415	Revenues from Merchandising, Jobbing and Contract Work	3,460,794	2,586,248	5,452,426
416	(Less) Costs and Expenses of Merch., Job and Contract Work	2,881,584	2,238,663	5,457,474
417	Revenues from Nonutility Operations	-	-	-
418	Nonoperating Rental Income	(2,619)	(2,945)	(3,178)
418.1	Equity in Earnings of Subsidiary Companies	1,798	7,690	11,291
419	Interest and Dividend Income	5,998,924	3,435,022	4,514,328
419.1	Allowance for Other Funds Used During Construction	6,566,573	8,839,677	1,377,486
421	Misc. Nonoperating Income	1,956,653	1,329,033	448,644
421.1	Gain on Disposition of Property	-	135,840	-
	Total Other Income	15,100,539	14,091,902	6,343,523
	Other Income Deductions:			
421.2	Loss on Disposition of Property	299,193	-	121,207
426.1	Donations	146,417	189,511	180,098
426.2	Life Insurance	(694,806)	(886,658)	94,695
426.3	Penalties	(590,249)	45,234	25,920
426.4	Exp. For Certain Civic, Political & Related Activities	85,192	52,166	67,267
426.5	Other Deductions	221,451	28,164,392	236,885
	Total Other Income Deductions	(532,802)	27,564,645	726,072
	Taxes Applicable to Other Income and Deductions:			
408.2	Taxes Other Than Income Taxes			
409.2	Income Taxes - Federal	266,868	(6,483,614)	1,342,032
409.2	Income Taxes - Other	19,443	(1,888,072)	567,717
410.2	Provision for Deferred Income Taxes	2,288,538	213,020	162,118
411.2	(Less) Provision for Deferred Income Taxes - Cr.	188,555	774,405	116,732
411.5	Investment Tax Credit Adjustment - Net	-	-	-
	Total Taxes on Other Income and Deductions	2,386,294	(8,933,071)	1,955,135
	NET OTHER INCOME AND DEDUCTIONS	13,247,047	(4,539,672)	3,662,316
	INTEREST CHARGES			
427	Interest on Long-Term Debt	114,804,122	100,939,056	90,992,663
428	Amort. Of Debt Disc and Expense	2,003,716	1,723,301	1,514,001
428.1	Amortization of Loss on Reacquired Debt	2,045,793	2,018,270	1,797,068
429.1	(Less) Amortization of Gain on reacquired Debt-Credit	46,734	19,716	19,716
430	Interest on Debt to Assoc. Companies	4,592,115	1,592,957	5,281,075
431	Other Interest Expense	4,153,285	5,488,432	7,432,257
432	(Less) Allowance for Borrowed Funds Used During Construction-Cr	3,689,419	4,424,505	3,340,778
	Net Interest Charges	123,862,878	107,317,795	103,656,570
	Income Before Extraordinary Items			
	NET INCOME	80,557,652	115,122,912	169,756,951

JERSEY CENTRAL POWER & LIGHT COMPANY
Balance Sheet at
December 31, 2018
ASSETS AND OTHER DEBITS

FERC Account		December 31, 2018
	UTILITY PLANT	
101-106	Utility plant	6,841,472,584
107	Construction Work in Progress	182,155,357
	Total Utility Plant	7,023,627,941
108,111	Less Accumulated Provision for Depreciation	2,148,322,401
	Net Utility Plant	4,875,305,540
120.1 - 120.4 and 120.6	Nuclear Fuel	
120.5	Accum. Provision for Amortization	0
	Net Nuclear Fuel	
	Net Utility Plant	4,875,305,540
	OTHER PROPERTY AND INVESTMENTS	
121	Nonutility Property	16,979,653
122	(Less) Accum. Prov. For Deprec. And Amort.	15,829,051
123	Investment in Associated Companies	-
123.1	Investment in Subsidiary companies	897,102
124	Other Investments	1,791
125-128	Special Funds	229,140,287
175	Long-Term Portion of Derivative Assets	43,797
	Total Other Property and Investments	231,233,579
	CURRENT AND ACCRUED ASSETS	
131	Cash	
132-134	Special Deposits	255,897,586
135	Working Funds	1,025
136	Temporary Cash Investments	
142	Customer Accounts Receivable	138,064,097
143	Other Accounts Receivable	34,248,612
144	(Less) Accum. Prov. For Uncollectible Accounts	4,436,362
145	Notes Receivable from Associated Companies	-
146	Accts. Receivable from Associated companies	62,710,890
151	Fuel Stock	-
154	Plant Materials and Operating Supplies	-
165	Prepayments	26,386,710
171	Interest and Dividend Receivable	-
172	Rents Receivable	4,785,226
173	Accrued Utility Revenues	86,376,550
174	Miscellaneous Current and Accrued Assets	-
175	Derivative Instruments Assets	43,797
175	(Less) Long Term Portion of Derivative Instrument Assets	43,797
	Total Current and Accrued Assets	604,034,334
	DEFERRED DEBITS	
181	Unamortized Debt Expenses	5,101,815
182.1	Extraordinary Property Losses	-
182.2	Unrecovered Plant and Study Costs	4,125,895
182.3	Other Regulatory Assets	779,264,940
183	Prelim. Survey and Investigation Charges	2,328,212
184	Clearing Accounts	149,166
185	Temporary Facilities	520,035
186	Miscellaneous Deferred Debits	1,814,479,673
188	Research, Devel. And Demonstration Expend.	41,466
189	Unamortized Loss on Reacquired Debt	5,593,655
190	Accumulated Deferred Income Taxes	952,319,382
	Total Deferred Debits	3,563,924,239
	TOTAL ASSETS	9,274,497,692

JERSEY CENTRAL POWER & LIGHT COMPANY
Balance Sheet at
December 31, 2018
LIABILITIES AND OTHER CREDITS

FERC Account		December 31, 2018
	PROPRIETARY CAPITAL	
201	Common Stock	136,284,470
204	Preferred Stock Issued	
207	Premium on Capital Stock	2,665,143,711
208-211	Other Paid-In Capital	46,295,786
215, 215.1,216	Retained Earnings	671,510,121
216.1	Unappropriated Undistributed Subsidiary Earnings	(38,436)
219	Accumulated Other Comprehensive Income	(5,575,366)
	Total Proprietary Capital	3,513,620,286
	LONG-TERM DEBT	
221	Bonds	
223	Advances From Associated Companies	
224	Other Long-Term Debt	1,550,000,000
225	Unamortized Premium on Long-Term Debt	-
226	(Less) Unamortized Discount on Long-Term Debt	4,799,265
	Total Long-Term Debt	1,545,200,735
	OTHER NON-CURRENT LIABILITES	
227	Obligations Under Capital Leases	7,687,074
228.2	Accumulated Provision for Injuries and Damages	4,773,214
228.3	Accumulated Provision for Pension and Benefits	227,999,377
	Long-Term Portion of Derivative Instrument Liabilities	-
230	Asset Retirement Obligation	172,830,642
	Total Noncurrent Liabilities	413,290,307
	CURRENT AND ACCRUED LIABILITIES	
231	Notes Payable	-
232	Accounts Payable	181,139,989
233	Notes Payable to Associated Companies	143,086,743
234	Accounts Payable to Associated Companies	4,958,531
235	Customer Deposits	46,891,725
236	Taxes Accrued	3,729,369
237	Interest Accrued	23,213,454
238	Dividends Declared	-
241	Tax Collections Payable	8,838,256
242	Misc Current and Accrued Liabilities	59,283,167
243	Obligations Under Capital Leases	392,405
244	Derivative Instrument Liabilities	-
	(Less) Long-Term Portion of Derivative Instruments-Hedges	-
	Total Current and Accrued Liabilities	471,533,639
	DEFERRED CREDITS	
252	Customer Advances for Construction	38,217,911
255	Accumulated Deferred Investment Tax Credits	1,786,148
253	Other Deferred Credits	557,458,644
254	Other Regulatory Liabilities	1,090,926,449
257	Unamortized Gain on Reacquired Debit	38,217
282	Accum. Deferred Income Taxes-Other Property	1,061,347,417
283	Accum. Deferred Income Taxes-Other	581,077,939
	Total Deferred Credits	3,330,852,725
	TOTAL LIABILITIES AND OTHER CREDITS	9,274,497,692
		-

Appendix E

JERSEY CENTRAL POWER & LIGHT COMPANY

Statement of the Amount of Total Revenue Derived in Calendar Year 2018
From Intrastate Sales and Services at Current Rates

Line #	Description	FERC Form-1 Page	FERC Form-1 Line	2018
1	Total Electric Operating Revenues	300	27	$ 1,841,851,146
2	Exclude:Contra Revenue Amounts in FERC 445	300	7	$ (21,713,709)
3	Revised Total Electric Operating Revenues			$ 1,863,564,855
4	Exclude: Sales for Resale Revenues	300	11	$ 32,010,716
5	Revised Total Electric Operating Revenues			$ 1,831,554,139
6	Total Add Back: Intrastate Sales for Resales			$ 4,627,068
7	Total Intrastate Revenues			$ 1,836,181,207

JERSEY CENTRAL POWER & LIGHT COMPANY **APPENDIX G**
Transactions with Associated (Affiliated) Companies
For the 12 Months Ended December 31, 2018

DESCRIPTION OF SERVICE	NAME OF AFFILIATED COMPANY	AMOUNT
Provide Chairman of the Board Support	First Energy Service Co	117
Provide Chief Executive Officer Support	First Energy Service Co	306,415
Provide President, FE Utilities Support	First Energy Service Co	832,328
Provide Transmission, Distribution Support	First Energy Service Co	30,917,410
Provide Utility Operations Support	First Energy Service Co	217,784
Provide Compliance & Regulatory Services Support	First Energy Service Co	1,851,204
Provide Customer Service Support	First Energy Service Co	14,831,312
Provide Energy Efficiency Support	First Energy Service Co	339,592
Provide Environmental Support	First Energy Service Co	937,152
Provide Chief Financial Officer & Strategic Planning & Operations Support	First Energy Service Co	202,158
Provide Corporate Services & Chief Information Officer Support	First Energy Service Co	21,817,260
Provide Supply Chain Support	First Energy Service Co	558,999
Provide Accounting Support	First Energy Service Co	7,167,194
Provide Treasury Support	First Energy Service Co	369,476
Provide Business Development Support	First Energy Service Co	281,121
Provide Integrated System Planning Support	First Energy Service Co	230,192
Provide Corporate Risk Support	First Energy Service Co	667,727
Provide Internal Audit Support	First Energy Service Co	425,613
Provide Legal Department Support	First Energy Service Co	4,603,218
Provide Rates & Regulatory Affairs Support	First Energy Service Co	1,678,539
Provide Corp/Real Estate Record Management Support	First Energy Service Co	3,098,317
Provide Corporate Affairs Support	First Energy Service Co	1,263,613
Provide External Affairs & Communication Support	First Energy Service Co	2,292,927
Provide Federal Affairs & Energy Policy Support	First Energy Service Co	299,949
Provide Local Affairs & Economic Development Support	First Energy Service Co	249,413
Provide State Affairs Support	First Energy Service Co	492,612
Provide Human Resource Support	First Energy Service Co	24,967,654
Provide Marketing & Branding Support	First Energy Service Co	1,225,448
Provide Generation Related Support	First Energy Service Co	1,509,833
Interest Income - Carrying Charges on Service Company Assets	First Energy Service Co	1,198,370
Interest Expense - Regulated Money Pool	First Energy Corp	5,281,075
Rent - Wadsworth Facility	American Transmission Systems Inc	520,251
Rent - Akron Control Facility	American Transmission Systems Inc	1,157,515
Rent - Pottsville Pike	Metropolitan Edison Company	751,358
Rent - Farimont Call Center	Monongahela Power Company	539,074
Rent - Greensburg Corporate Center	West Penn Power Company	826,104
Transmission Charge - TMI Unit 1	Mid-Atlantic Interstate Transmission, LLC	1,998,563
Transmission Investment - Power Pool Agreement	Mid-Atlantic Interstate Transmission, LLC	1,762,524
TMI Charges for Miscellaneous General and Outside Services		
	TOTAL	137,669,411

ACCOMMODATION OR CONVENIENCE PAYMENTS:

		2018
Purchased Power	First Energy Service Co	940,486,625
Interest	First Energy Service Co	91,389,280
Taxes	First Energy Service Co	134,765,333
Outside Contractors	First Energy Service Co	48,444,723
Employee Benefits	First Energy Service Co	232,216,381
Customer Expenses	First Energy Service Co	44,286,776
NJ Agent Payments	First Energy Service Co	65,278,016
Inventory/Equipment Costs	First Energy Service Co	7,863,628
Lease Costs	First Energy Service Co	15,461,278
Other Convenience Payments*	First Energy Service Co	359,611,822
	TOTAL	**1,939,803,862**

EXHIBIT JC-2

BEFORE THE

NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

James V. Fakult

Re: Overview and

Distribution Operations

DIRECT TESTIMONY OF JAMES V. FAKULT ON BEHALF OF JERSEY CENTRAL POWER & LIGHT COMPANY

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is James V. Fakult. My primary business address is 101 Crawford Corner Rd. Building #1, Suite 1-511, Holmdel, New Jersey 07733. I also have an office at the JCP&L Northern Region headquarters at 300 Madison Avenue, Morristown, New Jersey 07962.

Q. Please identify your employer and your current position.

A. I am employed by Jersey Central Power & Light Company ("JCP&L" or "Company") as President.

Q. Please describe your current responsibilities.

A. My responsibilities for JCP&L include leading the Company's management team in assuring the safe and reliable operation of the Company's distribution system through the efficient operation, utilization and management of JCP&L's distribution system, customer service functions, and human resources. This includes responsibility for the executive management of JCP&L's more than 1,290 employees and the construction, operation and maintenance of the equipment used to deliver electricity to more than one million customer locations. Additionally, I interact regularly with municipal, county and state elected officials, and support the Company's regulatory efforts, including with respect to keeping the Board of Public Utilities (the "Board") informed regarding important issues like service reliability and safety.

Q. Please describe your educational background, qualifications, and work experience.

A. My educational background, qualifications, and work experience are set forth in Appendix A.

Q. Have you previously testified in proceedings before the Board?

A. No.

Q. Please summarize your testimony.

A. JCP&L is requesting a base rate increase of $186.9 million on an annual basis, which will result in an overall average increase in JCP&L rates of 7.8%. I am proud to say that even with the Company's proposed rate increase, JCP&L residential rates (RS) will continue to be the lowest compared to other New Jersey's regulated electric distribution companies. One of the most significant cost increases for JCP&L that supports the requested rate relief is the increasing trend in the number and severity of weather events (significant and otherwise) JCP&L has experienced over the past four years. In fact, approximately 40% of the Company's requested rate relief is due to storms. As both Governor Murphy and the Board have observed, New Jersey has been experiencing more severe weather events over the years due to the phenomena of climate change. JCP&L has been affected by these severe weather events, more so than the other utilities in New Jersey, due to its very unique service territory which includes the heavily-forested northwestern portion of New Jersey and the central coastal portion of the State. *See* Thomas Workoff (Exhibit JC-8). As Company witness Dennis L. Pavagadhi (Exhibit JC-7) explains in more detail in his testimony, storm preparedness and restoration are an integral part of JCP&L's operations to ensure that the Company is able to restore electric service to its customers as quickly and safely as possible.

Q. Please explain how your testimony is organized.

A. My testimony provides an overview of the Company and its request for rate relief in this base rate case filing proceeding. First, I provide an overview of the electric distribution system, service territory and its organizational structure, and staffing. Second, I address the value the Company provides to our customers and the communities that JCP&L serves. Third, in support of the Company's need for rate relief, I discuss the continuing need to align revenues with the cost to provide safe and reliable electric service in particular with respect to the recovery of our deferred storm costs, which have accumulated since 2016 and include costs associated with significant storms, including those of March 2018, and more recent events. Finally, I introduce the other witnesses for the Company in this proceeding.

II. OVERVIEW OF COMPANY AND ITS SERVICE TERRITORY

Q. Please provide an overview of the Company.

A. Let me begin by saying that I am very proud to be the President of JCP&L and proud to be the leader of the very fine, talented, diverse and committed men and women who work for the Company.

Every day I witness the depth of our employees' commitment and dedication to providing our customers with safe and reliable electric service at affordable rates. Our Company is, and strives to be, a workplace that invites diversity. Through the

Company's diversity and inclusion programs, JCP&L maintains a high-performing team and works to create a culture where differences are respected, teamwork is encouraged, and employees feel valued, driven and empowered to do their best. Indeed, this past September 2019, JCP&L was recognized with a Commerce and Industry Association of New Jersey ("CIANJ") Best Practices award for the Company's diversity and inclusion programs.

To help train the next generation of well-educated industry workers, JCP&L teams with local community colleges, including Brookdale Community College and Raritan Valley Community College, through its award-winning Power Systems Institute ("PSI").

JCP&L's 1,290 employees take pride in supporting their local communities. The FirstEnergy Foundation and JCP&L have donated nearly $1.7 million over the last decade to New Jersey United Way agencies, and raised more than $179,300 and 175,000 pounds of food for New Jersey based food banks through Harvest for Hunger, an annual awareness campaign aimed at fighting hunger.

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JCP&L has, and will have, invested $1.028 billion in capital projects from January 1, 2016 through June 30, 2020 to enhance electric system resiliency and reliability for customers. Approximately $162.9 million of these expenditures are related to capitalized storm costs and approximately $63.8 million of these expenditures are related to JCP&L's Reliability Plus Infrastructure Investment Program ("JCP&L Reliability Plus").

The Company plans to spend approximately $35 million from June 2019 through June 2020 for additional enhancements, including trimming trees along nearly 3,300 miles of power lines as part of routine operations and maintenance ("O&M") to reduce vegetation-related outages. By maintaining a sharp focus on enhancing service reliability, building a strong workforce and supporting the communities and environment, JCP&L sustains its commitment to making its customers' lives better and brighter.

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I am privileged and very pleased to have this opportunity to support our Company in this proceeding, which I believe is an opportunity to address its very real financial needs, while demonstrating our many successes, and acknowledging the challenges that JCP&L faces in continuing to provide safe and reliable service to our customers.

Q. Please describe the Company's service territory.

A. The Company's service territory encompasses 3,300 square miles in two distinct regions: the Central Region in central coastal New Jersey, and the Northern Region, in the heavily-forested northwestern portion of the State. These two regions are served by 14 operating districts. In total, JCP&L provides electric distribution service to approximately 1.1 million residential, commercial and industrial customers, representing approximately 25% of the metered electric customers in New Jersey. The service territory includes all or parts of 13 counties and 236 municipalities, equaling approximately 45% of the municipalities in the State of New Jersey. Mr. Pavagadhi (Exhibit JC-7) as well as Mr. Thomas Workoff (Exhibit JC-8) provide additional details regarding certain geographic and topographical features that makes JCP&L's service territory very unique. I will next discuss the regions from the perspective of the customers and businesses JCP&L serves.

Q. Please describe the Company's Northern Region service territory.

A. Headquartered in Morristown, New Jersey, the Northern Region includes all or portions of the counties of Essex, Hunterdon, Mercer, Morris, Passaic, Somerset, Sussex, Union and Warren. The Northern Region extends south from Montague and follows along the eastern bank of the Delaware River to Washington's Crossing, northeast to Somerset, east to Millburn, north to Ringwood, west to the Sussex County border, then north to Vernon and back to Montague. JCP&L customers located in the Northern Region are served by six operating districts. The districts are located in Boonton, Dover, Flemington, Newton, Summit, and Washington.

Q. What are some of the distinguishing features of the Company's Northern Region service territory?

A. The Northern Region features a wide variety of contrasts. While the entire JCP&L service territory is generally wooded; the northwestern part of the territory, located within the Northern Region, is one of the most heavily forested areas in New Jersey. Also, as explained in more detail by Mr. Pavagadhi (Exhibit JC-7) and Mr. Workoff (Exhibit JC-8), the highest elevations in the State coincide with the Company's Northern Region, which experiences approximately twice the amount of snowfall and freezing rain as compared to the rest of New Jersey. There is a mix of rural and suburban with some portions that are densely populated and others that are sparsely populated. The region also serves as national or international headquarters for many large corporations. In addition, many corporations have located major research and development, manufacturing, operating, or data center facilities in this region. I should add that there are approximately 2,300 critical facilities located in the Northern Region including nearly thirty hospitals.

Q. Please describe the Company's Central Region service territory.

A. Headquartered in Red Bank, New Jersey, the Central Region includes all or portions of the counties of Burlington, Mercer, Middlesex, Monmouth, and Ocean. The Central Region follows the Raritan River from Sayreville to the Atlantic coast and covers the coast south to Barnegat, inland and west to Wrightstown, north to Hightstown and northeast back to Sayreville. JCP&L customers located in the Central Region are served by eight operating districts. The districts are located in Union Beach, Cookstown, Freehold, Lakewood, Long Branch, Old Bridge, Point Pleasant, and Berkeley.

Q. What are some of the distinguishing features of the Company's Central Region service territory?

A. The Central Region features a wide variety of demographic and geographic contrasts. The western portion of the territory has farmland communities, while the eastern portion is home to Jersey Shore communities (also described in more detail by Mr. Pavagadhi (Exhibit JC-7)), including two urban cities, Asbury Park and Long Branch. Major redevelopment projects continue in Asbury Park, Long Branch and the rebuilding of the homes and businesses on the barrier island directly or indirectly as a result of the impacts of Super Storm Sandy. I should add that there are approximately 2,400 critical facilities located in the Central Region, including nearly 20 hospitals.

Q. Please generally describe the Company's electrical system within the Company's service territory.

A. While I defer to the Company's witness, Mr. Pavagadhi (Exhibit JC-7), as to the details, I can tell you that the Company operates and maintains over 35,000 conductor miles of primary distribution circuits, and over 1,800 circuit miles (5,469 conductor miles) of sub-transmission circuits, in excess of 340,000 JCP&L-owned poles and approximately 250,000 transformers. JCP&L owns, operates and maintains 339 substations, 244 sub-transmission circuits and 1,162 primary distribution circuits. The Company's electrical distribution system includes both overhead infrastructure and underground infrastructure, including underground infrastructure that was installed to meet growth in the late 1960s and ear1y 1970s. Mr. Pavagadhi provides further operational details in his testimony (Exhibit JC-7).

Q. Please describe the mix of customers served by JCP&L.

A. The JCP&L customer base is 88% residential, 11% commercial and 1% industrial.

III. <u>ORGANIZATIONAL STRUCTURE AND WORKFORCE</u>

Q. Please explain how JCP&L's electric distribution organization is structured.

A. As an overview, JCP&L's local distribution organization is divided into two major functional areas, operations and external affairs. Company Operations are led by JCP&L's Vice President of Operations, who reports directly to me. The Company's External Affairs are led by the Vice President of External Affairs, who also reports directly to me, as does the Manager of Human Resources.

Reporting to the Vice President of Operations is the Director of Operations Services (*i.e.*, Company witness, Dennis L. Pavagadhi), the Director of Operations Support, the Director of Regional Operations Support and the Manager of Emergency Preparedness (collectively, the "Operations Leadership Team").

The Vice President of External Affairs is responsible for JCP&L's External Affairs Consultants as well as its Customer Support functions. JCP&L's External Affairs Consultants provide the local interface between JCP&L and all of the municipal and county organizations in the service territory. The Customer Support function is responsible for maintaining and fostering the relationship with all of JCP&L's larger customer accounts.

The Manager of Human Resources is responsible for the human resource administrative responsibilities associated with the management of JCP&L's talented and diverse bargaining and non-bargaining distribution operations workforce.

In addition, as further explained by Mr. Pavagadhi (Exhibit JC-7), the Company also receives support services from FirstEnergy Service Company ("Service Company"), including corporate support from the various corporate organizations of JCP&L's parent company, FirstEnergy, which are part of the Service Company.

Q. Please explain how JCP&L's local electric distribution organization is structured.

A. JCP&L's local distribution organization is divided into two major functional areas: operations and external affairs.

The Director of Operations Services, the Director of Operations Support, the Director of Regional Operations Support, and the Manager of Emergency Preparedness (collectively, the "Operations Leadership Team") report to the Vice President, Operations who, as I said above, reports to me.

Q. How does the Operations Leadership Team function?

A. Three operations' functions comprise the JCP&L Operations Leadership Team. They include Operations Services, Operations Support and Regional Operations Support.

Q. What does the Operations Services function do?

A. Operations Services includes the work performed by JCP&L's fourteen (14) local line shops constructing, inspecting and maintaining the Company's distribution line plant, JCP&L's local Engineering department, which performs distribution level system planning, reliability, design and project management functions, as well as the Company's Claims department.

Q. What does the Operations Support function do?

A. Operations Support includes the Substation department, which is responsible for the construction, inspection and maintenance of JCP&L's substation plant, its underground network and cable plant, the Regional Work Management function, and the two Regional Distribution Control Centers ("DCCs," each a "DCC"), which monitor and control the Company's electric distribution system.

Q. What does the Regional Operations Support function do?

A. Regional Operations Support includes the Distribution Forestry, Fleet, Meter Services, Meter Reading, Facilities and local Environmental departments.

Q. What does the Manager of Emergency Preparedness do?

A. The Manager of Emergency Preparedness oversees JCP&L's preparedness initiatives to help ensure a prompt and effective response to emergency events, including weather-related damage and serves as the Company's main liaison with federal, state and local emergency preparedness organizations before, during and after emergency events.

Q. Does JCP&L receive operational support from other parts of the FirstEnergy system?

A. Yes. the Company also receives support services from the Service Company, including general corporate, technical and systems management support. The role and function of the Service Company is discussed further in the direct testimony of Company witness, Olenger L. Pannell in Exhibit JC-15. Mr. Pavagadhi (Exhibit JC-7) provides additional descriptive information regarding the nature and extent of the operational support from various Service Company corporate departments, including but not limited to, importantly, from the Service Company Distribution Support function, which also provides similar support services for key functions used by the affiliated FirstEnergy utilities.

Q. Does JCP&L have a sufficient workforce in place to reliably operate its electric system?

A. Yes. I believe that JCP&L effectively manages its day-to-day work obligations with its own workforce and contractor personnel, including managing the established process to acquire assistance from both within the FirstEnergy system and from non-affiliated utilities and contractors during major storms. Since 2017, JCP&L has hired approximately 111 personnel, which includes 84 lineman and 27 substation personnel. These new hires are graduates from the PSI program, a partnership between the Company and Brookdale and Raritan Valley Community Colleges, which is a two-year program that combines classroom learning with hands-on training and is designed to produce well-trained, highly skilled employees to enhance the Company's workforce.

Finally, JCP&L, like all utilities, requires assistance for major storm restoration, and the Company has an established process to acquire assistance from both within the FirstEnergy system and from non-affiliated utilities and contractors. Mr. Pavagadhi (Exhibit JC-7) provides further explanation of such processes.

Q. Does JCP&L intend to hire additional line or substation personal in 2020?

A. Yes. Consistent with the pattern shown over the past three years, JCP&L plans to hire approximately 31 additional bargaining unit employees (as line workers (*i.e.*, 18) and substation electricians (*i.e.*, 13)) between January 1, 2020 and December 31, 2020. These employees will assist JCP&L in continuing to provide safe and reliable service to customers.

IV. <u>COMPANY'S BASE RATE INCREASE</u>

Q. Please explain the rationale for the Company's request for a rate increase.

A. As Company witness Mr. Mark A. Mader, the Director, Rates and Regulatory Affairs for New Jersey, explains (Exhibit JC-3), JCP&L has not filed a base rate case since 2016. The Company's current base rates are not sufficient for JCP&L to earn an appropriate rate of return on its rate base or to recover its annual O&M expense. As Mr. Mader also explains, growth in the Company's rate base from distribution capital spending and significant deferred storm expense are the primary drivers of this request for a rate increase. In addition, the Board Order approving JCP&L's Reliability Plus program requires that the Company file a base rate case no later than June 1, 2024. As Mr. Mader (Exhibit JC-3) further explains, this filing satisfies that requirement.

Q. What is the amount of the base rate increase sought by the Company in this proceeding?

A. As further discussed in Mr. Mader's testimony (Exhibit JC-3) and in the testimony and schedules of JCP&L witness Carol A. Pittavino (Exhibit JC-4), JCP&L requires a base rate increase of $186.9 million on an annual basis, which will result in an overall average increase in JCP&L rates of 7.8%.

Q. Based on the Company's proposed request, what will be the impact on the typical residential bill?

A. As Yongmei Peng (Exhibit JC-12) explains in further detail, the proposed rate increase and design results in an increase of $8.73 per month for the typical residential customer, representing an 8.5% increase.

Q. If the Company's proposed requests are approved, how will the Company's rates compare to the rates of New Jersey's other electric public utilities?

A. The Company's proposed rates will continue to compare extremely favorably to those of New Jersey's other electric utilities. Ms. Pittavino's direct testimony provides an illustration of JCP&L's lower rates as compared to the rates of the other New Jersey electric utilities.

Q. How will the proposed rate increase bring value to JCP&L's customers?

A. JCP&L must attract capital at cost-effective rates in order to remain a financially-strong company that can continue to invest in its distribution system. By authorizing the

Company to earn a fair rate of return, the Board will allow the Company to maintain the stability and profitability needed to attract investors and capital at cost-effective rates. As a result, the Company will then be well-positioned to continue its capital expenditures program, which will allow us to continue to meet our customers' and this Board's expectations for providing safe and reliable service. Moreover, since 2016, the Company's customers have enjoyed stable base rates that are, as indicated above, below those of the other New Jersey electric utilities. During the same time, JCP&L has also made, and continues to make, important investments in the electric distribution system to enhance service and reliability for its customers.

Q. Can you provide some additional information about the significant deferred storm expense that you mentioned above?

A. Yes. JCP&L has prudently incurred and deferred these costs that were necessary in planning for, responding to, and replacing facilities and equipment damaged as a result of such storms and making permanent repairs. As Mr. Pavagadhi (Exhibit JC-7) discusses, the Company has properly utilized its robust emergency recovery and restoration plan known as "E-Plan" and the incident command system ("ICS") structure to address the various storms giving rise to the deferred expenses. The Company has prudently addressed these storms, meeting applicable industry and regulatory standards and should be allowed to recover the deferred costs for these matters on a timely basis. I defer to the Mr. Mader's direct testimony (Exhibit JC-3) regarding rate recovery issues related to such costs, but do note that the Company is seeking a three year amortization period for these deferred storm costs.

Q. Why is timely recovery of these dollars important to JCP&L?

A. As I said, I defer to the direct testimony of Mr. Mader (Exhibit JC-3) regarding rate recovery issues related to such deferred costs, including the timing of such recovery. However, in my position as President of JCP&L, I have observed that extended deferred recovery can impact the Company's cash flow, which in turn impacts budgets, which then can impact the scope and scale of operations. Therefore, I believe recovery in the timeframe requested by the Company and as explained by Mr. Mader furthers the ability of the Company to meet its operational objectives, which are to provide safe and reliable service at reasonable cost to its customers.

V. <u>OVERVIEW OF THE PETITION</u>

Q. Please provide an overview of the base rate filing.

A. JCP&L's request for rate relief in this proceeding (the "Base Rate Filing") consists of the Company's Petition (the "Petition") for rate relief, and the direct testimonies and supporting exhibits of the Company witnesses who will testify on behalf of the Company and provide supporting documentation and exhibits.

Q. Please identify the other witnesses who are filing testimony in support of JCP&L's Base Rate Filing.

A. JCP&L is presenting the following witnesses for the following purposes:

- Mark A. Mader, Director, Rates and Regulatory Affairs for New Jersey, will provide an overview of the request for rate relief required to cover cost of service and provide an adequate return for investors. Mr. Mader will also discuss the basis of Company's request for a 3-year amortization of its deferred storm expense. He sponsors an adjustment related to revenue normalization. Mr. Mader also provides the calculation of a consolidated tax adjustment as required by the Board's regulations at N.J.A.C. 14:1-5.12(a)(11). He discusses and supports proposed changes to JCP&L's LED Street Lighting Tariff. Finally, Mr. Mader sponsors an adjustment to rate base to include capital investments made under the JCP&L Reliability Plus program, an infrastructure investment program, through December 31, 2020. *See* Exhibit JC-3.

- Carol A. Pittavino, N.J. State Regulatory Analyst for JCP&L, sponsors the Company's revenue requirements as well as certain accounting and normalization adjustments related to test year expenses, regulatory assets and liabilities, depreciation and rate base. *See* Exhibit JC-4.
- Jennifer Spricigo, Rates Analyst in the Service Company Rates & Regulatory Affairs Department for JCP&L, provides testimony regarding, and sponsors, certain normalization/annualization operations and maintenance ("O&M") expense adjustments to the test year ending June 30, 2020. *See* Exhibit JC-5.
- Tracy Ashton, Assistant Controller, Corporate of FirstEnergy, provides testimony on JCP&L's annual pension and other post-employment benefits expenses. *See* Exhibit JC-6.
- Dennis L. Pavagadhi, Director of Operations Services for JCP&L, describes JCP&L's distribution system, unique aspects of its service territory, its

organizational structure, its capital investment programs and its operations and maintenance programs (including, in particular its inspection and maintenance programs, vegetation management program and its storm recovery and restoration process) and related expenses in New Jersey that support safety, service quality and reliability including changes to some charges found in Appendix A of the Company's Tariff. *See* Exhibit JC-7.

- Thomas Workoff, Senior Scientist of Meteorology and UAS Services for the Service Company, describes the geographic and topographical features of JCP&L's service territory as well as the severe weather events experienced by JCP&L from 2016 to the present. *See* Exhibit JC-8.
- Joseph Dipre, Sr., Advisor, Strategy & Long Term Planning, at the Service Company, testifies to JCP&L's capital structure, embedded cost of long-term debt, and overall cost of capital. *See* Exhibit JC-9.
- Dylan W. D'Ascendis, a Director at ScottMadden, Inc., provides expert testimony on the appropriate rate of return on equity for JCP&L, given its risk position. *See* Exhibit JC-10.
- Stephanie Zieger, Analyst within the Service Company Rates and Regulatory Affairs Department, sponsors JCP&L's cost of service testimony and supporting studies filed in compliance with the cost of service methodology the Board approved in JCP&L's most recent base rate case and as proposed by the Company. *See* Exhibit JC-11.

- Yongmei Peng, N.J. State Regulatory Analyst V, Rates & Regulatory Affairs, sponsors the proposed rate design and proposed modifications to the tariff and schedules, including associated adjustments. Ms. Peng will also sponsor testimony on proof of revenues and customer bill impacts resulting from the filing. *See* Exhibit JC-12.
- Thomas Donadio, N.J. State Regulatory Analyst for JCP&L, sponsors proposed modifications to the tariff, including associated adjustments. *See* Exhibit JC-13.
- John J. Spanos, President of Gannett-Fleming, provides testimony summarizing a depreciation study and proposing revised depreciation accrual rates for JCP&L. *See* Exhibit JC-14.
- Olenger Pannell, Assistant Controller - FirstEnergy Utilities ("FEU"), provides testimony regarding FirstEnergy's cost allocation process and Service Company services and charges. *See* Exhibit JC-15.
- James O'Toole, Rates Analyst for the Service Company, sponsors the Lead/Lag Study used to determine the cash working capital requirement for JCP&L. *See* Exhibit JC-16.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

PROFESSIONAL AND EDUCATIONAL BACKGROUND
OF
JAMES V. FAKULT

My name is James V. Fakult and my business addresses are: 101 Crawford Corner Rd. Building #1, Suite 1-511, Holmdel, New Jersey 07733 and 300 Madison Avenue, Morristown, New Jersey 07962. I am employed as President of Jersey Central Power & Light Company.

I earned a bachelor's degree in marketing from Cleveland State University and a master's degree in business administration from Ashland University.

I joined FirstEnergy in 1987 as an associate marketing representative. Following a series of marketing-related promotions, I was named director, Sales, in 1999. In 2001 I was named director, Large Commercial & Industrial Segments. In 2004, I was promoted to director, Customer Support. I became the general manager, Regional Operations Support for Ohio Edison in 2008. In 2011, I was promoted to president of Maryland Operations for FirstEnergy. In June 2013, I became President of Jersey Central Power & Light Company.

I am the current chairman of the New Jersey Utilities Association and I also currently serve as the First Vice Chair and I am on the Executive Committee of the New Jersey State Chamber. In addition, I serve on the Board of Choose New Jersey as the Committee Chair, Finance & Audit as well as Chairman, Board of Trustees for the Paper Mill Playhouse in Millburn New Jersey.

EXHIBIT JC-2

BEFORE THE

NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

James V. Fakult

Re: Overview and

Distribution Operations

DIRECT TESTIMONY OF JAMES V. FAKULT ON BEHALF OF JERSEY CENTRAL POWER & LIGHT COMPANY

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is James V. Fakult. My primary business address is 101 Crawford Corner Rd. Building #1, Suite 1-511, Holmdel, New Jersey 07733. I also have an office at the JCP&L Northern Region headquarters at 300 Madison Avenue, Morristown, New Jersey 07962.

Q. Please identify your employer and your current position.

A. I am employed by Jersey Central Power & Light Company ("JCP&L" or "Company") as President.

Q. Please describe your current responsibilities.

A. My responsibilities for JCP&L include leading the Company's management team in assuring the safe and reliable operation of the Company's distribution system through the efficient operation, utilization and management of JCP&L's distribution system, customer service functions, and human resources. This includes responsibility for the executive management of JCP&L's more than 1,290 employees and the construction, operation and maintenance of the equipment used to deliver electricity to more than one million customer locations. Additionally, I interact regularly with municipal, county and state elected officials, and support the Company's regulatory efforts, including with respect to keeping the Board of Public Utilities (the "Board") informed regarding important issues like service reliability and safety.

Q. Please describe your educational background, qualifications, and work experience.

A. My educational background, qualifications, and work experience are set forth in Appendix A.

Q. Have you previously testified in proceedings before the Board?

A. No.

Q. Please summarize your testimony.

A. JCP&L is requesting a base rate increase of $186.9 million on an annual basis, which will result in an overall average increase in JCP&L rates of 7.8%. I am proud to say that even with the Company's proposed rate increase, JCP&L residential rates (RS) will continue to be the lowest compared to other New Jersey's regulated electric distribution companies. One of the most significant cost increases for JCP&L that supports the requested rate relief is the increasing trend in the number and severity of weather events (significant and otherwise) JCP&L has experienced over the past four years. In fact, approximately 40% of the Company's requested rate relief is due to storms. As both Governor Murphy and the Board have observed, New Jersey has been experiencing more severe weather events over the years due to the phenomena of climate change. JCP&L has been affected by these severe weather events, more so than the other utilities in New Jersey, due to its very unique service territory which includes the heavily-forested northwestern portion of New Jersey and the central coastal portion of the State. *See* Thomas Workoff (Exhibit JC-8). As Company witness Dennis L. Pavagadhi (Exhibit JC-7) explains in more detail in his testimony, storm preparedness and restoration are an integral part of JCP&L's operations to ensure that the Company is able to restore electric service to its customers as quickly and safely as possible.

Q. Please explain how your testimony is organized.

A. My testimony provides an overview of the Company and its request for rate relief in this base rate case filing proceeding. First, I provide an overview of the electric distribution system, service territory and its organizational structure, and staffing. Second, I address the value the Company provides to our customers and the communities that JCP&L serves. Third, in support of the Company's need for rate relief, I discuss the continuing need to align revenues with the cost to provide safe and reliable electric service in particular with respect to the recovery of our deferred storm costs, which have accumulated since 2016 and include costs associated with significant storms, including those of March 2018, and more recent events. Finally, I introduce the other witnesses for the Company in this proceeding.

II. OVERVIEW OF COMPANY AND ITS SERVICE TERRITORY

Q. Please provide an overview of the Company.

A. Let me begin by saying that I am very proud to be the President of JCP&L and proud to be the leader of the very fine, talented, diverse and committed men and women who work for the Company.

Every day I witness the depth of our employees' commitment and dedication to providing our customers with safe and reliable electric service at affordable rates. Our Company is, and strives to be, a workplace that invites diversity. Through the

Company's diversity and inclusion programs, JCP&L maintains a high-performing team and works to create a culture where differences are respected, teamwork is encouraged, and employees feel valued, driven and empowered to do their best. Indeed, this past September 2019, JCP&L was recognized with a Commerce and Industry Association of New Jersey ("CIANJ") Best Practices award for the Company's diversity and inclusion programs.

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Q. Please describe the Company's Northern Region service territory.

A. Headquartered in Morristown, New Jersey, the Northern Region includes all or portions of the counties of Essex, Hunterdon, Mercer, Morris, Passaic, Somerset, Sussex, Union and Warren. The Northern Region extends south from Montague and follows along the eastern bank of the Delaware River to Washington's Crossing, northeast to Somerset, east to Millburn, north to Ringwood, west to the Sussex County border, then north to Vernon and back to Montague. JCP&L customers located in the Northern Region are served by six operating districts. The districts are located in Boonton, Dover, Flemington, Newton, Summit, and Washington.

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A. The Northern Region features a wide variety of contrasts. While the entire JCP&L service territory is generally wooded; the northwestern part of the territory, located within the Northern Region, is one of the most heavily forested areas in New Jersey. Also, as explained in more detail by Mr. Pavagadhi (Exhibit JC-7) and Mr. Workoff (Exhibit JC-8), the highest elevations in the State coincide with the Company's Northern Region, which experiences approximately twice the amount of snowfall and freezing rain as compared to the rest of New Jersey. There is a mix of rural and suburban with some portions that are densely populated and others that are sparsely populated. The region also serves as national or international headquarters for many large corporations. In addition, many corporations have located major research and development, manufacturing, operating, or data center facilities in this region. I should add that there are approximately 2,300 critical facilities located in the Northern Region including nearly thirty hospitals.

Q. Please describe the Company's Central Region service territory.

A. Headquartered in Red Bank, New Jersey, the Central Region includes all or portions of the counties of Burlington, Mercer, Middlesex, Monmouth, and Ocean. The Central Region follows the Raritan River from Sayreville to the Atlantic coast and covers the coast south to Barnegat, inland and west to Wrightstown, north to Hightstown and northeast back to Sayreville. JCP&L customers located in the Central Region are served by eight operating districts. The districts are located in Union Beach, Cookstown, Freehold, Lakewood, Long Branch, Old Bridge, Point Pleasant, and Berkeley.

Q. What are some of the distinguishing features of the Company's Central Region service territory?

A. The Central Region features a wide variety of demographic and geographic contrasts. The western portion of the territory has farmland communities, while the eastern portion is home to Jersey Shore communities (also described in more detail by Mr. Pavagadhi (Exhibit JC-7)), including two urban cities, Asbury Park and Long Branch. Major redevelopment projects continue in Asbury Park, Long Branch and the rebuilding of the homes and businesses on the barrier island directly or indirectly as a result of the impacts of Super Storm Sandy. I should add that there are approximately 2,400 critical facilities located in the Central Region, including nearly 20 hospitals.

Q. Please generally describe the Company's electrical system within the Company's service territory.

A. While I defer to the Company's witness, Mr. Pavagadhi (Exhibit JC-7), as to the details, I can tell you that the Company operates and maintains over 35,000 conductor miles of primary distribution circuits, and over 1,800 circuit miles (5,469 conductor miles) of sub-transmission circuits, in excess of 340,000 JCP&L-owned poles and approximately 250,000 transformers. JCP&L owns, operates and maintains 339 substations, 244 sub-transmission circuits and 1,162 primary distribution circuits. The Company's electrical distribution system includes both overhead infrastructure and underground infrastructure, including underground infrastructure that was installed to meet growth in the late 1960s and ear1y 1970s. Mr. Pavagadhi provides further operational details in his testimony (Exhibit JC-7).

Q. Please describe the mix of customers served by JCP&L.

A. The JCP&L customer base is 88% residential, 11% commercial and 1% industrial.

III. <u>ORGANIZATIONAL STRUCTURE AND WORKFORCE</u>

Q. Please explain how JCP&L's electric distribution organization is structured.

A. As an overview, JCP&L's local distribution organization is divided into two major functional areas, operations and external affairs. Company Operations are led by JCP&L's Vice President of Operations, who reports directly to me. The Company's External Affairs are led by the Vice President of External Affairs, who also reports directly to me, as does the Manager of Human Resources.

Reporting to the Vice President of Operations is the Director of Operations Services (*i.e.*, Company witness, Dennis L. Pavagadhi), the Director of Operations Support, the Director of Regional Operations Support and the Manager of Emergency Preparedness (collectively, the "Operations Leadership Team").

The Vice President of External Affairs is responsible for JCP&L's External Affairs Consultants as well as its Customer Support functions. JCP&L's External Affairs Consultants provide the local interface between JCP&L and all of the municipal and county organizations in the service territory. The Customer Support function is responsible for maintaining and fostering the relationship with all of JCP&L's larger customer accounts.

The Manager of Human Resources is responsible for the human resource administrative responsibilities associated with the management of JCP&L's talented and diverse bargaining and non-bargaining distribution operations workforce.

In addition, as further explained by Mr. Pavagadhi (Exhibit JC-7), the Company also receives support services from FirstEnergy Service Company ("Service Company"), including corporate support from the various corporate organizations of JCP&L's parent company, FirstEnergy, which are part of the Service Company.

Q. Please explain how JCP&L's local electric distribution organization is structured.

A. JCP&L's local distribution organization is divided into two major functional areas: operations and external affairs.

The Director of Operations Services, the Director of Operations Support, the Director of Regional Operations Support, and the Manager of Emergency Preparedness (collectively, the "Operations Leadership Team") report to the Vice President, Operations who, as I said above, reports to me.

Q. How does the Operations Leadership Team function?

A. Three operations' functions comprise the JCP&L Operations Leadership Team. They include Operations Services, Operations Support and Regional Operations Support.

Q. What does the Operations Services function do?

A. Operations Services includes the work performed by JCP&L's fourteen (14) local line shops constructing, inspecting and maintaining the Company's distribution line plant, JCP&L's local Engineering department, which performs distribution level system planning, reliability, design and project management functions, as well as the Company's Claims department.

Q. What does the Operations Support function do?

A. Operations Support includes the Substation department, which is responsible for the construction, inspection and maintenance of JCP&L's substation plant, its underground network and cable plant, the Regional Work Management function, and the two Regional Distribution Control Centers ("DCCs," each a "DCC"), which monitor and control the Company's electric distribution system.

Q. What does the Regional Operations Support function do?

A. Regional Operations Support includes the Distribution Forestry, Fleet, Meter Services, Meter Reading, Facilities and local Environmental departments.

Q. What does the Manager of Emergency Preparedness do?

A. The Manager of Emergency Preparedness oversees JCP&L's preparedness initiatives to help ensure a prompt and effective response to emergency events, including weather-related damage and serves as the Company's main liaison with federal, state and local emergency preparedness organizations before, during and after emergency events.

Q. Does JCP&L receive operational support from other parts of the FirstEnergy system?

A. Yes. the Company also receives support services from the Service Company, including general corporate, technical and systems management support. The role and function of the Service Company is discussed further in the direct testimony of Company witness, Olenger L. Pannell in Exhibit JC-15. Mr. Pavagadhi (Exhibit JC-7) provides additional descriptive information regarding the nature and extent of the operational support from various Service Company corporate departments, including but not limited to, importantly, from the Service Company Distribution Support function, which also provides similar support services for key functions used by the affiliated FirstEnergy utilities.

Q. Does JCP&L have a sufficient workforce in place to reliably operate its electric system?

A. Yes. I believe that JCP&L effectively manages its day-to-day work obligations with its own workforce and contractor personnel, including managing the established process to acquire assistance from both within the FirstEnergy system and from non-affiliated utilities and contractors during major storms. Since 2017, JCP&L has hired approximately 111 personnel, which includes 84 lineman and 27 substation personnel. These new hires are graduates from the PSI program, a partnership between the Company and Brookdale and Raritan Valley Community Colleges, which is a two-year program that combines classroom learning with hands-on training and is designed to produce well-trained, highly skilled employees to enhance the Company's workforce.

Finally, JCP&L, like all utilities, requires assistance for major storm restoration, and the Company has an established process to acquire assistance from both within the FirstEnergy system and from non-affiliated utilities and contractors. Mr. Pavagadhi (Exhibit JC-7) provides further explanation of such processes.

Q. Does JCP&L intend to hire additional line or substation personal in 2020?

A. Yes. Consistent with the pattern shown over the past three years, JCP&L plans to hire approximately 31 additional bargaining unit employees (as line workers (*i.e.*, 18) and substation electricians (*i.e.*, 13)) between January 1, 2020 and December 31, 2020. These employees will assist JCP&L in continuing to provide safe and reliable service to customers.

IV. <u>COMPANY'S BASE RATE INCREASE</u>

Q. Please explain the rationale for the Company's request for a rate increase.

A. As Company witness Mr. Mark A. Mader, the Director, Rates and Regulatory Affairs for New Jersey, explains (Exhibit JC-3), JCP&L has not filed a base rate case since 2016. The Company's current base rates are not sufficient for JCP&L to earn an appropriate rate of return on its rate base or to recover its annual O&M expense. As Mr. Mader also explains, growth in the Company's rate base from distribution capital spending and significant deferred storm expense are the primary drivers of this request for a rate increase. In addition, the Board Order approving JCP&L's Reliability Plus program requires that the Company file a base rate case no later than June 1, 2024. As Mr. Mader (Exhibit JC-3) further explains, this filing satisfies that requirement.

Q. What is the amount of the base rate increase sought by the Company in this proceeding?

A. As further discussed in Mr. Mader's testimony (Exhibit JC-3) and in the testimony and schedules of JCP&L witness Carol A. Pittavino (Exhibit JC-4), JCP&L requires a base rate increase of $186.9 million on an annual basis, which will result in an overall average increase in JCP&L rates of 7.8%.

Q. Based on the Company's proposed request, what will be the impact on the typical residential bill?

A. As Yongmei Peng (Exhibit JC-12) explains in further detail, the proposed rate increase and design results in an increase of $8.73 per month for the typical residential customer, representing an 8.5% increase.

Q. If the Company's proposed requests are approved, how will the Company's rates compare to the rates of New Jersey's other electric public utilities?

A. The Company's proposed rates will continue to compare extremely favorably to those of New Jersey's other electric utilities. Ms. Pittavino's direct testimony provides an illustration of JCP&L's lower rates as compared to the rates of the other New Jersey electric utilities.

Q. How will the proposed rate increase bring value to JCP&L's customers?

A. JCP&L must attract capital at cost-effective rates in order to remain a financially-strong company that can continue to invest in its distribution system. By authorizing the

Company to earn a fair rate of return, the Board will allow the Company to maintain the stability and profitability needed to attract investors and capital at cost-effective rates. As a result, the Company will then be well-positioned to continue its capital expenditures program, which will allow us to continue to meet our customers' and this Board's expectations for providing safe and reliable service. Moreover, since 2016, the Company's customers have enjoyed stable base rates that are, as indicated above, below those of the other New Jersey electric utilities. During the same time, JCP&L has also made, and continues to make, important investments in the electric distribution system to enhance service and reliability for its customers.

Q. Can you provide some additional information about the significant deferred storm expense that you mentioned above?

A. Yes. JCP&L has prudently incurred and deferred these costs that were necessary in planning for, responding to, and replacing facilities and equipment damaged as a result of such storms and making permanent repairs. As Mr. Pavagadhi (Exhibit JC-7) discusses, the Company has properly utilized its robust emergency recovery and restoration plan known as "E-Plan" and the incident command system ("ICS") structure to address the various storms giving rise to the deferred expenses. The Company has prudently addressed these storms, meeting applicable industry and regulatory standards and should be allowed to recover the deferred costs for these matters on a timely basis. I defer to the Mr. Mader's direct testimony (Exhibit JC-3) regarding rate recovery issues related to such costs, but do note that the Company is seeking a three year amortization period for these deferred storm costs.

Q. Why is timely recovery of these dollars important to JCP&L?

A. As I said, I defer to the direct testimony of Mr. Mader (Exhibit JC-3) regarding rate recovery issues related to such deferred costs, including the timing of such recovery. However, in my position as President of JCP&L, I have observed that extended deferred recovery can impact the Company's cash flow, which in turn impacts budgets, which then can impact the scope and scale of operations. Therefore, I believe recovery in the timeframe requested by the Company and as explained by Mr. Mader furthers the ability of the Company to meet its operational objectives, which are to provide safe and reliable service at reasonable cost to its customers.

V. <u>OVERVIEW OF THE PETITION</u>

Q. Please provide an overview of the base rate filing.

A. JCP&L's request for rate relief in this proceeding (the "Base Rate Filing") consists of the Company's Petition (the "Petition") for rate relief, and the direct testimonies and supporting exhibits of the Company witnesses who will testify on behalf of the Company and provide supporting documentation and exhibits.

Q. Please identify the other witnesses who are filing testimony in support of JCP&L's Base Rate Filing.

A. JCP&L is presenting the following witnesses for the following purposes:

- Mark A. Mader, Director, Rates and Regulatory Affairs for New Jersey, will provide an overview of the request for rate relief required to cover cost of service and provide an adequate return for investors. Mr. Mader will also discuss the basis of Company's request for a 3-year amortization of its deferred storm expense. He sponsors an adjustment related to revenue normalization. Mr. Mader also provides the calculation of a consolidated tax adjustment as required by the Board's regulations at N.J.A.C. 14:1-5.12(a)(11). He discusses and supports proposed changes to JCP&L's LED Street Lighting Tariff. Finally, Mr. Mader sponsors an adjustment to rate base to include capital investments made under the JCP&L Reliability Plus program, an infrastructure investment program, through December 31, 2020. *See* Exhibit JC-3.

- Carol A. Pittavino, N.J. State Regulatory Analyst for JCP&L, sponsors the Company's revenue requirements as well as certain accounting and normalization adjustments related to test year expenses, regulatory assets and liabilities, depreciation and rate base. *See* Exhibit JC-4.
- Jennifer Spricigo, Rates Analyst in the Service Company Rates & Regulatory Affairs Department for JCP&L, provides testimony regarding, and sponsors, certain normalization/annualization operations and maintenance ("O&M") expense adjustments to the test year ending June 30, 2020. *See* Exhibit JC-5.
- Tracy Ashton, Assistant Controller, Corporate of FirstEnergy, provides testimony on JCP&L's annual pension and other post-employment benefits expenses. *See* Exhibit JC-6.
- Dennis L. Pavagadhi, Director of Operations Services for JCP&L, describes JCP&L's distribution system, unique aspects of its service territory, its

organizational structure, its capital investment programs and its operations and maintenance programs (including, in particular its inspection and maintenance programs, vegetation management program and its storm recovery and restoration process) and related expenses in New Jersey that support safety, service quality and reliability including changes to some charges found in Appendix A of the Company's Tariff. *See* Exhibit JC-7.

- Thomas Workoff, Senior Scientist of Meteorology and UAS Services for the Service Company, describes the geographic and topographical features of JCP&L's service territory as well as the severe weather events experienced by JCP&L from 2016 to the present. *See* Exhibit JC-8.
- Joseph Dipre, Sr., Advisor, Strategy & Long Term Planning, at the Service Company, testifies to JCP&L's capital structure, embedded cost of long-term debt, and overall cost of capital. *See* Exhibit JC-9.
- Dylan W. D'Ascendis, a Director at ScottMadden, Inc., provides expert testimony on the appropriate rate of return on equity for JCP&L, given its risk position. *See* Exhibit JC-10.
- Stephanie Zieger, Analyst within the Service Company Rates and Regulatory Affairs Department, sponsors JCP&L's cost of service testimony and supporting studies filed in compliance with the cost of service methodology the Board approved in JCP&L's most recent base rate case and as proposed by the Company. *See* Exhibit JC-11.

- Yongmei Peng, N.J. State Regulatory Analyst V, Rates & Regulatory Affairs, sponsors the proposed rate design and proposed modifications to the tariff and schedules, including associated adjustments. Ms. Peng will also sponsor testimony on proof of revenues and customer bill impacts resulting from the filing. *See* Exhibit JC-12.
- Thomas Donadio, N.J. State Regulatory Analyst for JCP&L, sponsors proposed modifications to the tariff, including associated adjustments. *See* Exhibit JC-13.
- John J. Spanos, President of Gannett-Fleming, provides testimony summarizing a depreciation study and proposing revised depreciation accrual rates for JCP&L. *See* Exhibit JC-14.
- Olenger Pannell, Assistant Controller - FirstEnergy Utilities ("FEU"), provides testimony regarding FirstEnergy's cost allocation process and Service Company services and charges. *See* Exhibit JC-15.
- James O'Toole, Rates Analyst for the Service Company, sponsors the Lead/Lag Study used to determine the cash working capital requirement for JCP&L. *See* Exhibit JC-16.

VI. <u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes.

PROFESSIONAL AND EDUCATIONAL BACKGROUND
OF
JAMES V. FAKULT

My name is James V. Fakult and my business addresses are: 101 Crawford Corner Rd. Building #1, Suite 1-511, Holmdel, New Jersey 07733 and 300 Madison Avenue, Morristown, New Jersey 07962. I am employed as President of Jersey Central Power & Light Company.

I earned a bachelor's degree in marketing from Cleveland State University and a master's degree in business administration from Ashland University.

I joined FirstEnergy in 1987 as an associate marketing representative. Following a series of marketing-related promotions, I was named director, Sales, in 1999. In 2001 I was named director, Large Commercial & Industrial Segments. In 2004, I was promoted to director, Customer Support. I became the general manager, Regional Operations Support for Ohio Edison in 2008. In 2011, I was promoted to president of Maryland Operations for FirstEnergy. In June 2013, I became President of Jersey Central Power & Light Company.

I am the current chairman of the New Jersey Utilities Association and I also currently serve as the First Vice Chair and I am on the Executive Committee of the New Jersey State Chamber. In addition, I serve on the Board of Choose New Jersey as the Committee Chair, Finance & Audit as well as Chairman, Board of Trustees for the Paper Mill Playhouse in Millburn New Jersey.

EXHIBIT JC-3

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony
of
Mark A. Mader

RE:
Revenue Normalization Adjustment, Consolidated Tax Adjustment, Storm Cost Amortization, LED Street Lighting Tariff Changes, and JCP&L Reliability Plus Program

DIRECT TESTIMONY OF MARK A. MADER ON BEHALF OF
JERSEY CENTRAL POWER & LIGHT COMPANY

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Mark A. Mader, and my business address is 300 Madison Ave, Morristown, NJ 07960.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company, and my title is Director, Rates and Regulatory Affairs for New Jersey. My time is devoted to rates and regulatory tasks performed for Jersey Central Power & Light Company ("JCP&L" or the "Company") under the jurisdiction of the New Jersey Board of Public Utilities ("Board" or "BPU"). My qualifications are set forth in detail in Appendix A to my testimony.

Q. **Have you previously testified in BPU proceedings?**

A. Yes, I testified on behalf of JCP&L in its two most recent base rate cases, BPU Docket No. ER12111052 and BPU Docket No. ER16040383. I have also testified before the Public Utilities Commission of Ohio, the West Virginia Public Service Commission, the Virginia State Corporation Commission, the Pennsylvania Public Utility Commission and the United States District Court for the Southern District of Ohio, Eastern Division.

Q. Please describe the purpose of your testimony.

A. In my testimony, I provide an overview of the request for rate relief required to cover cost of service and provide an adequate return for investors. I'll discuss the basis of Company's request for a 3-year amortization of its deferred storm expense. I also sponsor an adjustment related to revenue normalization. I provide the calculation of a consolidated tax adjustment as required by the Board in its regulations. I will discuss and support proposed changes to JCP&L's LED Street Lighting Tariff. Finally, I also sponsor an adjustment to rate base to include capital investments made under JCP&L Reliability Plus Infrastructure Investment Program ("JCP&L Reliability Plus"), an infrastructure investment program, through December 31, 2020.

Q. Please describe and summarize the content of your testimony.

A. My testimony addresses the following topics:

Amortization of Deferred Storm Expense: The Company is requesting a 3-year amortization of its $307.3 million storm-related regulatory asset balance (December 31, 2019). The Company's request results in an increase in overall storm cost recovery of $17.6 million as compared to the level of storm cost recovery collected through base rates and including storm cost recovery under the Storm Recovery Charge Rider ("SRC") as effective on November 1, 2019. Using a 5-year historical view to establish the annual amortization of the storm-related regulatory asset balance for ratemaking purposes has not been effective at controlling growth in the storm-related regulatory asset balance. The Company believes that a shorter amortization period would moderate the magnitude of the storm-related regulatory asset balance and support greater net reductions in the Company's deferred storm expense within the recovery period, especially in light of the increased frequency and severity of storm activity (*See* the direct testimony of Thomas Workoff, Exhibit JC-8), the level of storm damage sustained from these events, and the current level of the storm-related regulatory asset balance.

Revenue Normalization Adjustment: JCP&L proposes to adjust test year revenues by ($9.9 million). Consistent with its practice, the BPU approved a weather normalization adjustment in JCP&L's 2016 and 2012 base rate cases and in the Company's previous base rate proceedings.

Consolidated Tax Adjustment: Using the methodology set forth in the Board's regulation at *N.J.A.C.* 14:1-5.12(a), the result is a $20.8 million reduction to rate base.

LED Street Lighting Tariff: The Company is proposing to make adjustments to its LED Street Lighting Tariff, including: 1) add a contribution fixture service to the LED Street Lighting tariff; 2) revise the rates and charges for its LED Street Lighting; 3) add a 30W LED cobra head fixture to its tariff offering; 4) include language to address responsibility for the cost of police assistance when deemed necessary by local authorities; 5) establish a fixture-only rate, where the customer will be responsible for the cost of any additional facilities (i.e., other than the fixture), including, but not limited to the fixture pole, street lighting wire or bracket (arm), where not existing; and 6) add a provision for seasonal service.

JCP&L Reliability Plus program– Roll-in to Base Rates: JCP&L is proposing to roll all of the $97.01 million of JCP&L Reliability Plus program investments into rate base in conjunction with the conclusion of this base rate case. The Company is proposing that the prudence review for all JCP&L Reliability Plus program investments that are placed in service by June 30, 2020 be conducted as part of this case. The Company's Rider Reliability Plus ("RP") will continue to collect costs associated with the JCP&L Reliability Plus program until the conclusion of this base rate case.

II. REQUEST FOR RATE RELIEF

Q. Why is JCP&L filing a base rate case at this time?

A. JCP&L filed its last base rate case in 2016. The Company's current base rates are not sufficient for JCP&L to earn an appropriate rate of return on its rate base or to recover its annual operations and maintenance ("O&M") expense. JCP&L's total distribution capital expenditures from January 1, 2016 through June 30, 2020 will be $1.028 billion, which includes approximately $162.9 million of capitalized storm costs and approximately $63.8 million for the JCP&L Reliability Plus program. In addition, the Board Order approving the JCP&L Reliability Plus program requires that the Company file a base rate case no later than June 1, 2024. This filing satisfies that requirement.

Q. Is the Company requesting an increase in its base rates in this filing?

A. Yes. As discussed in the direct testimony and schedules of JCP&L witness Carol A. Pittavino (Exhibit JC-4), JCP&L requires a base rate increase of $186.9 million on an annual basis. This will result in a 7.8% overall average increase in JCP&L's rates.

Q. What are the most significant cost increases for JCP&L that support the requested rate relief?

A. JCP&L's total pro forma O&M expense during the test year was $219.9 million which reflects an increase of $7.5 million as compared to the Company's request in the 2016 base rate case, which is reflected on Schedule CAP-1 to the direct testimony of Carol A. Pittavino, Exhibit JC-4. JCP&L's rate base has increased from $2.217 billion, as approved in its 2016 base rate case[1], to $2.599 billion, as proposed in this case, an increase of $381.8 million. As I explain in more detail below, due to the increasing trend in the number of significant weather events JCP&L has experienced, the Company's deferred storm regulatory asset balance is $307.3 million (12/31/19). The deferred storm regulatory asset balance does not accrue interest and the storm amortization included in current base

[1] *I/M/O the Verified Petition of Jersey Central Power & Light Company for Review and Approval of an Increase in and Adjustments to Its Unbundled Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith, et al.*, BPU Docket No. ER16040384, Order dated December 12, 2016.

distribution rates is not sufficient to both address intra-year storm activity and sufficiently recover the regulatory asset balance. Therefore, the Company is requesting to amortize its deferred storm costs over a three-year period. *See* the direct testimony of Carol A. Pittavino (Exhibit JC-4). Another driver for the proposed revenue increase is an increase in depreciation expense.

III. <u>AMORTIZATION OF DEFERRED STORM EXPENSE</u>

Q. What is the Company's proposal to recover the storm-related regulatory asset balance?

A. The Company's request is to recover the $307.3 million storm-related regulatory asset balance through base rate amortization over a 3-year period.

Q. Why does the Company believe a 3-year amortization period is more appropriate in this case?

A. Since the Company's 2012 base rate case, the Board's practice has been to allow JCP&L to amortize the storm-related regulatory asset balance, based on the average of the most recent 5-year experience for deferred storm expense. Using a 5-year historical view to establish the annual amortization of the storm-related regulatory asset balance for ratemaking purposes has not been effective at controlling growth in the storm-related regulatory asset balance. The Company believes that a shorter amortization period would moderate the magnitude of the storm-related regulatory asset balance and support greater net reductions in the Company's deferred storm expense within the recovery period, especially in light of the increased frequency and severity of storm activity (*See* the direct testimony of Thomas Workoff, Exhibit JC-8), the level of storm damage sustained from these events, and the current level of the storm-related regulatory asset balance.

Q. Please explain.

A. Consider a circumstance where the Company's deferred storm expense over the next 5 years is equal to the historical 5-year average of deferred storm expense used to set the annual amortization of the storm-related regulatory asset balance. In such case, there would be no reduction to the storm-related regulatory asset balance over the next 5 years. The current practice only results in a net reduction to the storm-related regulatory asset balance to the extent that the storm experience over the next 5 years is not as severe as (i.e., deferred storm costs are less) the historical period on which the amortization was based. Because there is likely to be, and given the recent increase in the frequency and severity of storms impacting JCP&L's service territory (*See* the direct testimony of Thomas Workoff, Exhibit JC-8) there is probability that there will be, deferrable storm expense over the 5-year amortization period, the Board's past practice likely would not enable the storm-related regulatory asset balance to be extinguished within 5 years. For these reasons, the Company believes a shorter amortization will function to reduce the magnitude of the storm-related regulatory asset balances.

Q. How does a 3-year amortization of the storm-related regulatory asset balance improve recovery of overall storm expense?

A. Modifying the amortization period to 3 years would provide a greater opportunity for the Company to recover both its storm-related regulatory asset balance and its current (intra-year) deferred storm expense over the next 5 years. To explain, each year during the proposed 3-year amortization period, JCP&L likely will incur some amount of deferrable storm expense, which will increase the storm-related regulatory asset balance, offsetting the annual reduction in the storm-related regulatory asset from amortization and extending the period of time it will take for the storm-related regulatory asset to be extinguished (i.e., reach $0 balance). For example, assuming JCP&L incurs an annual average deferred storm expense of approximately $40 million, while the storm-related regulatory asset balance is being amortized using the Company's proposed 3-year amortization of $102.4 million, storm-related regulatory asset balance of $307.3 million would not be extinguished until 2025. As a reference, JCP&L's 5-year average annual deferred storm expense, excluding the March 2018 storms, is approximately $40 million.

Q. Has the Board previously considered and approved accelerated recovery of the storm-related regulatory asset balance?

A. Yes. Prior to the Company's 2012 base rate case, in 2002 base rate case, the BPU had approved a 3-year amortization of storm-related regulatory asset balances.[2] Again in 2016, the Board found it appropriate and approved accelerated recovery of storm costs. In the Generic Major Storm Events proceeding, the Board approved the recovery of JCP&L's O&M expenses for the 2012 Major Storms ($247 million) by establishing Rider SRC (Storm Recovery Charge) with rates effective April 1, 2015. The Board subsequently approved accelerated amortization of the SRC balance, which resulted in the full recovery by December 31, 2019. Rider SRC was cancelled on December 1, 2019. Beginning January 1, 2017, the Company's annual deferred storm cost recovery in base rates was

[2] BPU Order, dated May 31, 2005, Docket No. ER080506 et al. (*In the Matter of the Verified Petition of Jersey Central Power and Light Company for Review and Approval of an Increase and Adjustments to its Unbundled Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith*).

$25.6 million and $59.2 million through the SRC, or a total of $84.8 million. Based on rates effective November 1, 2019, including the SRC, the average monthly bill for a residential customer (768 kWh) was $104.53. The Company's proposed three-year amortization of the storm-related regulatory asset balance in this case would result in annual deferred storm cost recovery totaling $102.4 million, as compared to $84.8 million while the SRC was in effect. The incremental $17.6 million would result in an increase to the average monthly bill for a residential customer (768 kWh) of $0.79 or 0.8%. Essentially, the Company's request for deferred storm recovery in this case simply seeks to reestablish amortization of its storm-related regulatory asset balance at a level previously authorized by the BPU.

Q. Should the BPU approve a 3-year amortization of the storm-related regulatory asset balance and should the Company not file a base rate case within the next 3 years (i.e., prior to the expiration of the amortization), without an adjustment to base rates at the end of the amortization period, wouldn't the result be a windfall for the Company?

A. No. The Company's proposal here is simply for reasonable and more efficient recovery of amounts it has expended; nothing more. Should the Company's deferred storm balance be extinguished, that is, reduced to $0 prior it its next base rate case, the Company would set aside the remainder to be refunded to customers or held in reserve for future storms, at the direction of the Board. An alternative, and more appropriate recovery mechanism, would be to allow rider recovery of the storm-related regulatory asset balance, such as was the case with the SRC.

Q. Is base rate treatment for deferred storm expense the most effective recovery mechanism?

A. No. Base rate treatment is not the most appropriate recovery mechanism for significant expenses that may vary widely from year to year. Because of the magnitude and variability of JCP&L's storm expense, the recovery of storms costs is better suited for a clause (rider) mechanism. Rider treatment of deferred storm expense, such as JCP&L's previous SRC, would enable rates to be adjusted more frequently (annually), which would enable better matching of expense and recovery.

Q. Are there financial implications related to the large deferred storm balance?

A. Yes. Company witness Joseph Dipre (Exhibit JC-9) highlights the significant improvements JCP&L has made since its 2016 base rate case in the strength of its balance sheet and its credit ratings. Nonetheless, carrying large storm-related regulatory asset balances impacts cash flow and, therefore, cash flow metrics, such as FFO/Debt. Further, while unrecovered, these funds are unavailable for investments in service improvements, such as reliability, resiliency and storm hardening programs. When considering that the Board's past practice results in recovery periods of 5 years or more, it is especially impactful that carrying costs are not applied to the storm-related regulatory asset balance.

IV. REVENUE NORMALIZATION ADJUSTMENT

Q. Why is it necessary to adjust retail sales to reflect normal weather?

A. Weather variance impacts the opportunity for JCP&L to recover its operating costs and earn its allowed return on investment. Should rates be established on billing determinants from a test year that reflected higher than average sales due to weather, the Company would not recover its test year costs during a year of more moderate weather. Likewise, should rates be established on billing determinants from a test year that reflects lower than average sales due to weather, the Company would over-recover its test year costs during a year of more moderate weather. Therefore, JCP&L has included an adjustment to remove the effects of abnormal weather on test year revenues to set rates based on average (or weather-normalized) sales data, and thereby increase the probability that the Company will recover its test year costs and earn its allowed return, no more or no less.

Q. Is a weather-adjustment to retail sales a customary adjustment in an electric utility base rate case in New Jersey?

A. Yes. The Board's practice is to use weather-normalized sales in setting electric utility base rates. The BPU approved a weather normalization adjustment in JCP&L's 2016 and 2012 base rate cases[3]and in the Company's previous base rate proceedings.

Q. How does JCP&L determine what portion of its actual retail sales are weather sensitive?

A. A mathematical relationship is developed for JCP&L's distribution system throughput and daily weather data using degree days. This mathematical relationship is determined through regression analysis using 5 years of daily degree-day ("DD") data and historical billed loads by customer. Customer-specific degree-day coefficients arising from the regression analysis were aggregated to the customer class level to develop class-specific

[3] *I/M/O the Verified Petition of Jersey Central Power & Light Company for Review and Approval of an Increase in and Adjustments to Its Unbundled Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith, et al.*, BPU Docket No. ER16040384, Order dated December 12, 2016; *I/M/O the Verified Petition of Jersey Central Power & Light Company for Review and Approval of an Increase in and Adjustments to Its Unbundled Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program*, BPU Docket No. ER12111052, Order dated March 18, 2015.

coefficients. The output of the models is weather-sensitive load as a function of weather (nonlinear slopes in kWh/temperature) for each day. The daily kWh/temperature slopes from the regression analysis are then multiplied by the daily deviation of actual average daily temperature from normal temperatures (20-year daily averages) to yield the total weather-related sales adjustment for JCP&L.

Q. From what reporting stations does JCP&L collect the weather data that is used to normalize its retail sales?

A. A weighted average of 75% of the weather data reported by the Newark weather station and 25% reported by the Atlantic City weather station is used for JCP&L.

Q. How are the results from the regression analysis used to weather-adjust retail sales for each customer class?

A. The class-level coefficients are applied to the daily temperature deviations to arrive at weather sensitive sales by customer class. The adjustments are applied to the actual monthly sales such that positive adjustments are added in cases of less than average monthly weather and negative adjustments are added in cases of greater than average monthly weather.

Q. Are there adjustments made for classes that generally are not weather sensitive?

A. No. Industrial and Public Street and Highway Lighting customers do not require weather normalization, as these customers are minimally or non-weather sensitive. Therefore, these classes receive no allocation of weather-sensitive sales.

Q. How is the adjustment to retail sales then converted to revenues?

A. The weather adjustments allocated to the residential and commercial classes are priced on an incremental basis per the appropriate tariff rate schedule, pricing the weather-sensitive sales according to the respective kWh rate block in which weather-sensitive sales have been adjusted.

Q. Were customer charges or other non-kWh charges adjusted for weather?

A. No. Weather does not impact monthly charges such as customer charges and outdoor lighting charges.

Q. What is the weather normalization adjustment to revenues that JCP&L is proposing?

A. JCP&L proposes to adjust test year revenues by ($9.9 million), the calculation of which is set forth in Schedule CAP-2, Adjustment No. 1 to the direct testimony of Carol A. Pittavino (Exhibit JC-4).

V. CONSOLIDATED TAX ADJUSTMENT

Q. Have you performed a consolidated tax adjustment calculation in conjunction with this filing?

A. Yes. Schedule MAM-1 provides a consolidated tax adjustment calculation, using the methodology set forth in the Board's regulation at *N.J.A.C.* 14:1-5.12(a). The result of the calculation is a $20.8 million reduction to rate base.

VI. LED STREET LIGHTING TARIFF

Q. Is JCP&L proposed changes to its LED Street Lighting Tariff as part of this filing?

A. Yes.

Q. Can you explain the reasons for the proposed changes?

A. Yes. The Company's current LED Street Lighting tariff went into effect in late 2016, upon the conclusion of the 2016 base rate case. Since that time, JCP&L has received feedback from its customers about features that they would like to see offered with the LED Street Lighting service. Therefore, the Company is proposing several modifications to the LED service offerings to better serve its customer base.

Q. What are the key changes to the LED Street Lighting service?

A. First, the Company is proposing to add a contribution fixture service to the LED Street Lighting tariff. Under this option, the customer makes an upfront contribution in aid of construction to the cost of the fixtures, which results in lower ongoing monthly charges. Several municipal customers have stated that they prefer the contribution fixture option for this type of service. In addition, adding a contribution fixture option to the LED tariff will make it similar to JCP&L's other street lighting services, which already have this option. In the case of LED Contribution Fixtures, 2 levels of contributions will be available, each with a corresponding monthly fixture charge.

Second, the Company has updated the rates and charges for its LED Street Lighting service. *See* MAM-2 through 5.

Third, the Company is adding a 30W LED cobra head fixture to its tariff offering. As LED technology has improved, the efficacy (lumens/watt) have increased. This enables lower wattage retrofit options for existing 50W high-pressure sodium (HPS) and 100W mercury vapor (MV) cobra head fixtures, with greater energy savings.

Fourth, the Company proposes to include language in the tariff that is currently found in its JCP&L Municipal Lighting Handbook, which addresses responsibility for the cost of police assistance when deemed necessary by local authorities when existing street lights are converted to LED street lights.

Fifth, where needed to provide service under Schedule LED, the customer will be responsible for the cost of any additional facilities (i.e., other than the fixture), including, but not limited to the fixture pole, street lighting wire or bracket (arm), where not existing. The monthly rate under Schedule LED is a fixture-only rate. This change was made based on cost causation principles to assign these costs to the customers that cause them. This change also has the effect of removing the credit for a fixture pole when calculating underground streetlight installation costs. Over the past five (5) years, on average, JCP&L has installed 695 fixtures, both overhead and underground, in new locations. Therefore, this change is not expected to be impactful to customers taking service under Schedule LED.

Lastly, seasonal service has been included under Schedule LED, which adding a seasonal service option to the LED tariff will make it similar to JCP&L's other street lighting services, which already have this option.

The proposed changes to the LED Street Lighting tariff can be found in Schedule YP-5 to the direct testimony of Yongmei Peng.

Q. Looking at Schedules MAM-2 through MAM-4, why is it necessary to make an adjustment to the monthly fixture charge to reflect the proposed base rate increase?

A. It is JCP&L's practice to allocate distribution base rate changes (increases/decreases) to both the monthly fixture charge and the monthly distribution charge under its street lighting schedules, which practice has been accepted by the BPU in prior proceedings. This adjustment reflects the allocation of the proposed base rate increase to the monthly fixture charge under Schedule LED.

Q. How does the Company propose to recover the stranded asset value (i.e., remaining net book value) of fixtures that are retired and are retrofitted with LEDs?

A. The Company requests regulatory asset treatment for the stranded asset value, recovered through a Rider based on a rolling 5-year period, including a return on the regulatory asset balance at the Company's weighted average cost of capital. The Company believes that there are societal benefits from the conversion of streetlights in the form of reduced energy consumption and carbon emissions, which will contribute the statewide energy efficiency goals. Therefore, the Company proposes to socialize the recovery of the stranded asset value for the fixtures retired.

VII. <u>JCP&L RELIABILITY PLUS PROGRAM – ROLL-IN TO BASE RATES</u>

Q. Please explain the JCP&L Reliability Plus program.

A. The JCP&L Reliability Plus program is an infrastructure investment program, under which the Board authorized JCP&L to undertake certain electric distribution capital projects totaling $97.01 million.[4] JCP&L Reliability Plus program capital investments are to be made between June 1, 2019 and December 31, 2020. JCP&L is to recover JCP&L Reliability Plus program capital costs and associated depreciation expense through the Reliability Plus Rate Mechanism Rider RP.

Q. Does the Board's Order approving the JCP&L Reliability Plus program allow the program's capital investments to be rolled into JCP&L's rate base?

[4] *I/M/O the Verified Petition of Jersey Central Power & Light Company for Approval of an Infrastructure Investment Program (JCP&L Reliability Plus),* BPU Docket No. EO18070728, Order dated May 8, 2019.

A. Yes. Paragraph 37 of the Order (which summarizes Paragraph 37 of the Stipulation of Settlement) states:

> Notwithstanding any other provision of the Stipulation, should the Company file a base rate case prior to the conclusion of the term of JCP&L Reliability Plus, it may elect to include (i.e., roll into base rates) eligible JCP&L Reliability Plus investments in such a base rate case.

[JCP&L Reliability Plus Order, at p. 11]

Q. What is the Company proposing in regard to JCP&L Reliability Plus program investments in this filing?

A. JCP&L is proposing to roll all of the $97.01 million of JCP&L Reliability Plus program investments into rate base in conjunction with the conclusion of this base rate case. This amount is reflected on Schedule CAP-5 to the direct testimony of Carol A. Pittavino, Exhibit JC-4.

Q. In addition to the JCP&L Reliability Plus Order, is there other authority for this proposal?

A. Yes. As Carol Pittavino discusses in her testimony in this case (Exhibit JC-4), the Board's long-standing *Elizabethtown Water* precedent allows a utility to include known and measurable capital additions that will be in-service within six months after the end of the test year. All of the JCP&L Reliability Plus program investments will be in-service by December 31, 2020, which is within six months after the test-year end date of June 30, 2020.

Q. The JCP&L Reliability Plus Order also requires a prudence review in a base rate case. Is JCP&L proposing that the prudence review be conducted as part of this case?

A. Yes, in part. The Company is proposing that the prudence review for all JCP&L Reliability Plus program investments that are placed in service by June 30, 2020 be conducted as part of this case. Any remaining JCP&L Reliability Plus program investments that are placed in service after that date can be reviewed in the Company's next subsequent base rate case.

Q. How will this proposal impact JCP&L's Reliability Plus Rate Mechanism?

A. The Company's Rider RP will continue to collect costs associated with the JCP&L Reliability Plus program until the conclusion of this base rate case. For example, in September 2019, JCP&L made the first JCP&L Reliability Plus program rate filing with the Board. Pursuant to that filing, the Rider RP rates are scheduled to become effective as of March 1, 2020. That rate change will proceed as scheduled. However, upon the conclusion of this base rate case and the roll-in of the JCP&L Reliability Plus program investments into JCP&L's rate base, the Rider RP rates will be set to zero. Any residual balance from the final reconciliation of Rider RP will be transferred to Rider NGC.

Q. Does this conclude your direct testimony at this time?

A. Yes. However, I reserved the right to file additional testimony in this matter.

Experience and Education

My name is Mark A. Mader and my business address is 300 Madison Avenue, Morristown, NJ. I am employed by FirstEnergy Service Corporation as Director, Rates and Regulatory Affairs. My current duties and responsibilities include oversight of all aspects of electric rate case preparation, revenue requirement development, regulatory finance, cost allocation, regulated pricing and tariff services, rate design and relationship management with the BPU Staff. These responsibilities encompass the distribution and transmission segments of JCP&L.

I graduated from West Virginia University in 1986, where I earned a Bachelor of Science in Mechanical Engineering.

I was employed by Allegheny Energy for approximately 25 years. There, I held the positions of: Director, Energy Procurement; Director, Asset Management; and Director, Load Management. Upon completion of the acquisition of Allegheny Energy, Inc. by FirstEnergy Corp., I relocated to New Jersey in the position of Senior Advisor. In January, 2012 I was promoted to my current position.

JERSEY CENTRAL POWER & LIGHT

Consolidated Tax Adjustment
BPU Methodology under N.J.A.C 14:1-5.12(a)(11) - Five Years of Data, 75%/25% Sharing, Distribution Only

YEAR	Utility Taxable Income/(Loss)	Total Affiliate Taxable Losses	Statutory Tax Rate	Tax on Cumulative Losses Before AMT	AMT	Total Net Tax on Losses
2014	87,591,649	(2,505,461,153)	35.00%	(876,911,404)		(876,911,404)
2015	119,675,176	(1,972,268,231)	35.00%	(690,293,881)		(690,293,881)
2016	89,964,078	(1,799,851,068)	35.00%	(629,947,874)		(629,947,874)
2017	219,631,235	(1,053,292,640)	35.00%	(368,652,424)	11,721,807	(356,930,617)
2018	(234,326,028)	(816,225,976)	21.00%	(171,407,455)		(171,407,455)
TOTAL	282,536,110	(8,147,099,068)		(2,737,213,037)		(2,725,491,230)

Utility Percentage of Net Gain	4.10%
Sharing Percentage	25%
Distribution Percentage	74.41%
CTA Rate Base Adjustment	**(20,787,390)**

JCP&L LED Street Lighting Monthly Fixture Charge Derivation

Assumption Description	
Book Depreciation Rate	6.67%
Book Life of Investment (yrs)	15.00
Tax Life of Investment (yrs)	7.00
Debt Ratio	47.20%
Equity Ratio	52.80%
Debt Cost	5.083%
Equity Cost	10.15%
Overall Rate of Return (ROR)	7.76%
State Income Tax Rate	9.00%
Federal Income Tax rate	21.00%
Composite Income Tax Rate	28.11%

Summary LED Levelized Monthly Fixture Charge

	Cobra Head 2400 L 30W	Cobra Head 4000 L 50W	Cobra Head 7000 L 90W	Cobra Head 11500 L 130W	Cobra Head 24000 L 260W	Acorn 2500 L 50W	Acorn 5000 L 90W	Colonial 2500 L 50W	Colonial 5000 L 90W
Total Install Costs Per Unit	$ 611.33	$ 607.83	$ 656.50	$ 745.92	$ 947.17	$ 1,548.75	$ 1,496.25	$ 872.33	$ 1,046.83
Total Revenue Requirement	$ 1,029.08	$ 1,023.14	$ 1,105.70	$ 1,257.40	$ 1,598.80	$ 2,619.33	$ 2,530.27	$ 1,471.84	$ 1,767.87
Revenue Requirement NPV	$ 595.99	$ 592.55	$ 640.37	$ 728.22	$ 925.94	$ 1,516.98	$ 1,465.40	$ 852.41	$ 1,023.86
Annual Levelized Payment	$ 68.61	$ 68.21	$ 73.71	$ 83.83	$ 106.59	$ 174.62	$ 168.68	$ 98.12	$ 117.86
Monthly Fixture Charge	$ 5.72	$ 5.68	$ 6.14	$ 6.99	$ 8.88	$ 14.55	$ 14.06	$ 8.18	$ 9.82
Adjustment for Base Rate Increase	$ 0.98	$ 0.97	$ 1.05	$ 1.20	$ 1.52	$ 2.50	$ 2.41	$ 1.40	$ 1.69
Proposed Monthly Fixture Charge	$ 6.70	$ 6.65	$ 7.19	$ 8.19	$ 10.40	$ 17.05	$ 16.47	$ 9.58	$ 11.51
Proposed Monthly Fixture Charge (Including 6.625% SUT)	$ 7.14	$ 7.09	$ 7.67	$ 8.73	$ 11.09	$ 18.18	$ 17.56	$ 10.21	$ 12.27

LED Street Lighting Levelized Fixture Charge Calculation														
(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$526.33													
1	$491.24	$35.09	14.29%	$75.21	$11.28	$11.28	$479.96	$11.52	$25.72	-$1.22	$85.00	$167.38	$155.33	$68.61
2	$456.15	$35.09	24.49%	$128.90	$26.37	$37.65	$418.50	$10.04	$22.43	-$17.60	$0.00	$76.33	$65.73	$68.61
3	$421.06	$35.09	17.49%	$92.06	$16.01	$53.66	$367.40	$8.81	$19.69	-$8.31	$0.00	$71.29	$56.98	$68.61
4	$385.98	$35.09	12.49%	$65.74	$8.62	$62.28	$323.70	$7.77	$17.35	-$1.83	$0.00	$66.99	$49.68	$68.61
5	$350.89	$35.09	8.93%	$47.00	$3.35	$65.63	$285.26	$6.84	$15.29	$2.63	$0.00	$63.20	$43.50	$68.61
6	$315.80	$35.09	8.92%	$46.95	$3.33	$68.96	$246.84	$5.92	$13.23	$1.84	$0.00	$59.41	$37.95	$68.61
7	$280.71	$35.09	8.93%	$47.00	$3.35	$72.31	$208.40	$5.00	$11.17	$1.02	$0.00	$55.62	$32.97	$68.61
8	$245.62	$35.09	4.46%	$23.47	-$3.26	$69.04	$176.58	$4.24	$9.46	$6.96	$0.00	$52.49	$28.87	$68.61
9	$210.53	$35.09	0.00%	$0.00	-$9.86	$59.18	$151.35	$3.63	$8.11	$13.04	$0.00	$50.00	$25.52	$68.61
10	$175.44	$35.09	0.00%	$0.00	-$9.86	$49.32	$126.13	$3.03	$6.76	$12.51	$0.00	$47.52	$22.51	$68.61
11	$140.35	$35.09	0.00%	$0.00	-$9.86	$39.45	$100.90	$2.42	$5.41	$11.98	$0.00	$45.03	$19.79	$68.61
12	$105.27	$35.09	0.00%	$0.00	-$9.86	$29.59	$75.68	$1.82	$4.06	$11.45	$0.00	$42.55	$17.36	$68.61
13	$70.18	$35.09	0.00%	$0.00	-$9.86	$19.73	$50.45	$1.21	$2.70	$10.92	$0.00	$40.06	$15.17	$68.61
14	$35.09	$35.09	0.00%	$0.00	-$9.86	$9.86	$25.23	$0.61	$1.35	$10.39	$0.00	$37.57	$13.20	$68.61
15	$0.00	$35.09	0.00%	$0.00	-$9.86	$0.00	$0.00	$0.00	$0.00	$9.86	$0.00	$35.09	$11.44	$68.61
Total	**$0.00**	**$526.33**	**100.00%**	**$526.33**	**$0.00**	**$0.00**	**$0.00**	**$72.85**	**$162.73**	**$63.63**	**$85.00**	**$910.53**	**$595.99**	**$1,029.08**

Levelized Payment	$68.61

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$522.83													
1	$487.97	$34.86	14.29%	$74.71	$11.20	$11.20	$476.77	$11.44	$25.55	-$1.21	$85.00	$166.84	$154.82	$68.21
2	$453.12	$34.86	24.49%	$128.04	$26.19	$37.40	$415.72	$9.97	$22.28	-$17.48	$0.00	$75.82	$65.30	$68.21
3	$418.26	$34.86	17.49%	$91.44	$15.91	$53.31	$364.96	$8.76	$19.56	-$8.26	$0.00	$70.82	$56.60	$68.21
4	$383.41	$34.86	12.49%	$65.30	$8.56	$61.86	$321.55	$7.71	$17.23	-$1.82	$0.00	$66.54	$49.35	$68.21
5	$348.55	$34.86	8.93%	$46.69	$3.33	$65.19	$283.36	$6.80	$15.19	$2.61	$0.00	$62.78	$43.21	$68.21
6	$313.70	$34.86	8.92%	$46.64	$3.31	$68.50	$245.20	$5.88	$13.14	$1.83	$0.00	$59.02	$37.69	$68.21
7	$278.84	$34.86	8.93%	$46.69	$3.33	$71.83	$207.01	$4.97	$11.09	$1.01	$0.00	$55.25	$32.75	$68.21
8	$243.99	$34.86	4.46%	$23.32	-$3.24	$68.58	$175.40	$4.21	$9.40	$6.92	$0.00	$52.14	$28.68	$68.21
9	$209.13	$34.86	0.00%	$0.00	-$9.80	$58.79	$150.34	$3.61	$8.06	$12.95	$0.00	$49.67	$25.35	$68.21
10	$174.28	$34.86	0.00%	$0.00	-$9.80	$48.99	$125.29	$3.01	$6.71	$12.42	$0.00	$47.20	$22.36	$68.21
11	$139.42	$34.86	0.00%	$0.00	-$9.80	$39.19	$100.23	$2.40	$5.37	$11.90	$0.00	$44.73	$19.66	$68.21
12	$104.57	$34.86	0.00%	$0.00	-$9.80	$29.39	$75.17	$1.80	$4.03	$11.37	$0.00	$42.26	$17.24	$68.21
13	$69.71	$34.86	0.00%	$0.00	-$9.80	$19.60	$50.11	$1.20	$2.69	$10.85	$0.00	$39.79	$15.06	$68.21
14	$34.86	$34.86	0.00%	$0.00	-$9.80	$9.80	$25.06	$0.60	$1.34	$10.32	$0.00	$37.32	$13.11	$68.21
15	$0.00	$34.86	0.00%	$0.00	-$9.80	$0.00	$0.00	$0.00	$0.00	$9.80	$0.00	$34.86	$11.36	$68.21
Total	**$0.00**	**$522.83**	**100.00%**	**$522.83**	**$0.00**	**$0.00**	**$0.00**	**$72.36**	**$161.64**	**$63.20**	**$85.00**	**$905.04**	**$592.55**	**$1,023.14**

Levelized Payment	**$68.21**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$571.50													
1	$533.40	$38.10	14.29%	$81.67	$12.25	$12.25	$521.15	$12.50	$27.93	-$1.33	$85.00	$174.45	$161.89	$73.71
2	$495.30	$38.10	24.49%	$139.96	$28.63	$40.88	$454.42	$10.90	$24.35	-$19.11	$0.00	$82.88	$71.37	$73.71
3	$457.20	$38.10	17.49%	$99.96	$17.39	$58.27	$398.93	$9.57	$21.38	-$9.03	$0.00	$77.41	$61.87	$73.71
4	$419.10	$38.10	12.49%	$71.38	$9.36	$67.62	$351.48	$8.43	$18.84	-$1.99	$0.00	$72.73	$53.94	$73.71
5	$381.00	$38.10	8.93%	$51.03	$3.64	$71.26	$309.74	$7.43	$16.60	$2.85	$0.00	$68.62	$47.23	$73.71
6	$342.90	$38.10	8.92%	$50.98	$3.62	$74.88	$268.02	$6.43	$14.36	$2.00	$0.00	$64.51	$41.20	$73.71
7	$304.80	$38.10	8.93%	$51.03	$3.64	$78.51	$226.29	$5.43	$12.13	$1.11	$0.00	$60.40	$35.80	$73.71
8	$266.70	$38.10	4.46%	$25.49	-$3.54	$74.97	$191.73	$4.60	$10.28	$7.56	$0.00	$56.99	$31.35	$73.71
9	$228.60	$38.10	0.00%	$0.00	-$10.71	$64.26	$164.34	$3.94	$8.81	$14.15	$0.00	$54.29	$27.71	$73.71
10	$190.50	$38.10	0.00%	$0.00	-$10.71	$53.55	$136.95	$3.29	$7.34	$13.58	$0.00	$51.59	$24.44	$73.71
11	$152.40	$38.10	0.00%	$0.00	-$10.71	$42.84	$109.56	$2.63	$5.87	$13.01	$0.00	$48.90	$21.49	$73.71
12	$114.30	$38.10	0.00%	$0.00	-$10.71	$32.13	$82.17	$1.97	$4.40	$12.43	$0.00	$46.20	$18.85	$73.71
13	$76.20	$38.10	0.00%	$0.00	-$10.71	$21.42	$54.78	$1.31	$2.94	$11.86	$0.00	$43.50	$16.47	$73.71
14	$38.10	$38.10	0.00%	$0.00	-$10.71	$10.71	$27.39	$0.66	$1.47	$11.28	$0.00	$40.80	$14.33	$73.71
15	$0.00	$38.10	0.00%	$0.00	-$10.71	$0.00	$0.00	$0.00	$0.00	$10.71	$0.00	$38.10	$12.42	$73.71
Total	**$0.00**	**$571.50**	**100.00%**	**$571.50**	**$0.00**	**$0.00**	**$0.00**	**$79.10**	**$176.69**	**$69.09**	**$85.00**	**$981.38**	**$640.37**	**$1,105.70**

Levelized Payment	$73.71

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$660.92													
1	$616.86	$44.06	14.29%	$94.45	$14.16	$14.16	$602.70	$14.46	$32.30	-$1.53	$85.00	$188.45	$174.88	$83.83
2	$572.80	$44.06	24.49%	$161.86	$33.11	$47.28	$525.52	$12.61	$28.16	-$22.10	$0.00	$95.85	$82.54	$83.83
3	$528.74	$44.06	17.49%	$115.59	$20.11	$67.38	$461.35	$11.07	$24.72	-$10.44	$0.00	$89.52	$71.54	$83.83
4	$484.67	$44.06	12.49%	$82.55	$10.82	$78.20	$406.47	$9.75	$21.78	-$2.30	$0.00	$84.11	$62.38	$83.83
5	$440.61	$44.06	8.93%	$59.02	$4.20	$82.41	$358.21	$8.59	$19.20	$3.30	$0.00	$79.36	$54.62	$83.83
6	$396.55	$44.06	8.92%	$58.95	$4.19	$86.59	$309.96	$7.44	$16.61	$2.31	$0.00	$74.60	$47.65	$83.83
7	$352.49	$44.06	8.93%	$59.02	$4.20	$90.80	$261.69	$6.28	$14.02	$1.28	$0.00	$69.85	$41.40	$83.83
8	$308.43	$44.06	4.46%	$29.48	-$4.10	$86.70	$221.73	$5.32	$11.88	$8.75	$0.00	$65.91	$36.25	$83.83
9	$264.37	$44.06	0.00%	$0.00	-$12.39	$74.31	$190.05	$4.56	$10.19	$16.37	$0.00	$62.79	$32.05	$83.83
10	$220.31	$44.06	0.00%	$0.00	-$12.39	$61.93	$158.38	$3.80	$8.49	$15.70	$0.00	$59.67	$28.26	$83.83
11	$176.25	$44.06	0.00%	$0.00	-$12.39	$49.54	$126.70	$3.04	$6.79	$15.04	$0.00	$56.55	$24.86	$83.83
12	$132.18	$44.06	0.00%	$0.00	-$12.39	$37.16	$95.03	$2.28	$5.09	$14.38	$0.00	$53.43	$21.79	$83.83
13	$88.12	$44.06	0.00%	$0.00	-$12.39	$24.77	$63.35	$1.52	$3.40	$13.71	$0.00	$50.30	$19.04	$83.83
14	$44.06	$44.06	0.00%	$0.00	-$12.39	$12.39	$31.68	$0.76	$1.70	$13.05	$0.00	$47.18	$16.58	$83.83
15	$0.00	$44.06	0.00%	$0.00	-$12.39	$0.00	$0.00	$0.00	$0.00	$12.39	$0.00	$44.06	$14.36	$83.83
Total	**$0.00**	**$660.92**	**100.00%**	**$660.92**	**$0.00**	**$0.00**	**$0.00**	**$91.48**	**$204.34**	**$79.90**	**$85.00**	**$1,121.63**	**$728.22**	**$1,257.40**

Levelized Payment	**$83.83**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$862.17													
1	$804.69	$57.48	14.29%	$123.20	$18.48	$18.48	$786.22	$18.86	$42.13	-$2.00	$85.00	$219.95	$204.11	$106.59
2	$747.21	$57.48	24.49%	$211.15	$43.20	$61.67	$685.54	$16.45	$36.74	-$28.83	$0.00	$125.03	$107.67	$106.59
3	$689.74	$57.48	17.49%	$150.79	$26.23	$87.90	$601.83	$14.44	$32.25	-$13.62	$0.00	$116.78	$93.33	$106.59
4	$632.26	$57.48	12.49%	$107.69	$14.11	$102.02	$530.24	$12.72	$28.42	-$3.00	$0.00	$109.73	$81.38	$106.59
5	$574.78	$57.48	8.93%	$76.99	$5.49	$107.50	$467.28	$11.21	$25.04	$4.31	$0.00	$103.52	$71.25	$106.59
6	$517.30	$57.48	8.92%	$76.91	$5.46	$112.96	$404.34	$9.70	$21.67	$3.01	$0.00	$97.32	$62.16	$106.59
7	$459.82	$57.48	8.93%	$76.99	$5.49	$118.45	$341.38	$8.19	$18.30	$1.67	$0.00	$91.12	$54.01	$106.59
8	$402.35	$57.48	4.46%	$38.45	-$5.35	$113.10	$289.25	$6.94	$15.50	$11.41	$0.00	$85.98	$47.29	$106.59
9	$344.87	$57.48	0.00%	$0.00	-$16.16	$96.94	$247.93	$5.95	$13.29	$21.35	$0.00	$81.91	$41.81	$106.59
10	$287.39	$57.48	0.00%	$0.00	-$16.16	$80.79	$206.60	$4.96	$11.07	$20.49	$0.00	$77.84	$36.87	$106.59
11	$229.91	$57.48	0.00%	$0.00	-$16.16	$64.63	$165.28	$3.97	$8.86	$19.62	$0.00	$73.76	$32.43	$106.59
12	$172.43	$57.48	0.00%	$0.00	-$16.16	$48.47	$123.96	$2.97	$6.64	$18.75	$0.00	$69.69	$28.43	$106.59
13	$114.96	$57.48	0.00%	$0.00	-$16.16	$32.31	$82.64	$1.98	$4.43	$17.89	$0.00	$65.62	$24.84	$106.59
14	$57.48	$57.48	0.00%	$0.00	-$16.16	$16.16	$41.32	$0.99	$2.21	$17.02	$0.00	$61.55	$21.62	$106.59
15	$0.00	$57.48	0.00%	$0.00	-$16.16	$0.00	$0.00	$0.00	$0.00	$16.16	$0.00	$57.48	$18.74	$106.59
Total	**$0.00**	**$862.17**	**100.00%**	**$862.17**	**$0.00**	**$0.00**	**$0.00**	**$119.33**	**$266.56**	**$104.23**	**$85.00**	**$1,437.28**	**$925.94**	**$1,598.80**

Levelized Payment	**$106.59**

Notes:

Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$1,463.75													
1	$1,366.17	$97.58	14.29%	$209.17	$31.37	$31.37	$1,334.80	$32.02	$71.53	-$3.40	$85.00	$314.11	$291.50	$174.62
2	$1,268.58	$97.58	24.49%	$358.47	$73.34	$104.70	$1,163.88	$27.92	$62.37	-$48.95	$0.00	$212.27	$182.81	$174.62
3	$1,171.00	$97.58	17.49%	$256.01	$44.53	$149.24	$1,021.76	$24.51	$54.76	-$23.12	$0.00	$198.27	$158.45	$174.62
4	$1,073.42	$97.58	12.49%	$182.82	$23.96	$173.20	$900.22	$21.60	$48.24	-$5.10	$0.00	$186.29	$138.16	$174.62
5	$975.83	$97.58	8.93%	$130.71	$9.31	$182.51	$793.32	$19.03	$42.52	$7.31	$0.00	$175.76	$120.96	$174.62
6	$878.25	$97.58	8.92%	$130.57	$9.27	$191.78	$686.47	$16.47	$36.79	$5.11	$0.00	$165.23	$105.53	$174.62
7	$780.67	$97.58	8.93%	$130.71	$9.31	$201.09	$579.57	$13.90	$31.06	$2.83	$0.00	$154.69	$91.69	$174.62
8	$683.08	$97.58	4.46%	$65.28	-$9.08	$192.01	$491.07	$11.78	$26.32	$19.37	$0.00	$145.97	$80.29	$174.62
9	$585.50	$97.58	0.00%	$0.00	-$27.43	$164.58	$420.92	$10.10	$22.56	$36.25	$0.00	$139.06	$70.98	$174.62
10	$487.92	$97.58	0.00%	$0.00	-$27.43	$137.15	$350.76	$8.42	$18.80	$34.78	$0.00	$132.15	$62.60	$174.62
11	$390.33	$97.58	0.00%	$0.00	-$27.43	$109.72	$280.61	$6.73	$15.04	$33.31	$0.00	$125.23	$55.05	$174.62
12	$292.75	$97.58	0.00%	$0.00	-$27.43	$82.29	$210.46	$5.05	$11.28	$31.84	$0.00	$118.32	$48.27	$174.62
13	$195.17	$97.58	0.00%	$0.00	-$27.43	$54.86	$140.31	$3.37	$7.52	$30.37	$0.00	$111.41	$42.18	$174.62
14	$97.58	$97.58	0.00%	$0.00	-$27.43	$27.43	$70.15	$1.68	$3.76	$28.90	$0.00	$104.50	$36.71	$174.62
15	$0.00	$97.58	0.00%	$0.00	-$27.43	$0.00	$0.00	$0.00	$0.00	$27.43	$0.00	$97.58	$31.81	$174.62
Total	**$0.00**	**$1,463.75**	**100.00%**	**$1,463.75**	**$0.00**	**$0.00**	**$0.00**	**$202.59**	**$452.55**	**$176.95**	**$85.00**	**$2,380.84**	**$1,516.98**	**$2,619.33**

Levelized Payment	**$174.62**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$1,411.25													
1	$1,317.17	$94.08	14.29%	$201.67	$30.24	$30.24	$1,286.92	$30.88	$68.97	-$3.27	$85.00	$305.90	$283.87	$168.68
2	$1,223.08	$94.08	24.49%	$345.62	$70.71	$100.95	$1,122.14	$26.92	$60.14	-$47.19	$0.00	$204.66	$176.25	$168.68
3	$1,129.00	$94.08	17.49%	$246.83	$42.94	$143.88	$985.12	$23.63	$52.79	-$22.29	$0.00	$191.16	$152.77	$168.68
4	$1,034.92	$94.08	12.49%	$176.27	$23.10	$166.99	$867.93	$20.82	$46.51	-$4.91	$0.00	$179.61	$133.21	$168.68
5	$940.83	$94.08	8.93%	$126.02	$8.98	$175.96	$764.87	$18.35	$40.99	$7.05	$0.00	$169.45	$116.63	$168.68
6	$846.75	$94.08	8.92%	$125.88	$8.94	$184.90	$661.85	$15.88	$35.47	$4.93	$0.00	$159.30	$101.74	$168.68
7	$752.67	$94.08	8.93%	$126.02	$8.98	$193.88	$558.78	$13.41	$29.95	$2.73	$0.00	$149.15	$88.40	$168.68
8	$658.58	$94.08	4.46%	$62.94	-$8.75	$185.13	$473.46	$11.36	$25.37	$18.68	$0.00	$140.74	$77.41	$168.68
9	$564.50	$94.08	0.00%	$0.00	-$26.45	$158.68	$405.82	$9.74	$21.75	$34.95	$0.00	$134.07	$68.44	$168.68
10	$470.42	$94.08	0.00%	$0.00	-$26.45	$132.23	$338.18	$8.11	$18.12	$33.53	$0.00	$127.41	$60.35	$168.68
11	$376.33	$94.08	0.00%	$0.00	-$26.45	$105.79	$270.55	$6.49	$14.50	$32.12	$0.00	$120.74	$53.08	$168.68
12	$282.25	$94.08	0.00%	$0.00	-$26.45	$79.34	$202.91	$4.87	$10.87	$30.70	$0.00	$114.08	$46.54	$168.68
13	$188.17	$94.08	0.00%	$0.00	-$26.45	$52.89	$135.27	$3.25	$7.25	$29.28	$0.00	$107.41	$40.66	$168.68
14	$94.08	$94.08	0.00%	$0.00	-$26.45	$26.45	$67.64	$1.62	$3.62	$27.86	$0.00	$100.75	$35.39	$168.68
15	$0.00	$94.08	0.00%	$0.00	-$26.45	$0.00	$0.00	$0.00	$0.00	$26.45	$0.00	$94.08	$30.67	$168.68
Total	**$0.00**	**$1,411.25**	**100.00%**	**$1,411.25**	**$0.00**	**$0.00**	**$0.00**	**$195.33**	**$436.32**	**$170.61**	**$85.00**	**$2,298.50**	**$1,465.40**	**$2,530.27**

Levelized Payment	**$168.68**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$787.33													
1	$734.84	$52.49	14.29%	$112.51	$16.87	$16.87	$717.97	$17.23	$38.48	-$1.83	$85.00	$208.24	$193.24	$98.12
2	$682.35	$52.49	24.49%	$192.82	$39.45	$56.32	$626.03	$15.02	$33.55	-$26.33	$0.00	$114.18	$98.33	$98.12
3	$629.86	$52.49	17.49%	$137.70	$23.95	$80.27	$549.59	$13.19	$29.45	-$12.44	$0.00	$106.64	$85.23	$98.12
4	$577.38	$52.49	12.49%	$98.34	$12.89	$93.16	$484.22	$11.62	$25.95	-$2.74	$0.00	$100.20	$74.31	$98.12
5	$524.89	$52.49	8.93%	$70.31	$5.01	$98.17	$426.72	$10.24	$22.87	$3.93	$0.00	$94.54	$65.06	$98.12
6	$472.40	$52.49	8.92%	$70.23	$4.99	$103.16	$369.24	$8.86	$19.79	$2.75	$0.00	$88.87	$56.76	$98.12
7	$419.91	$52.49	8.93%	$70.31	$5.01	$108.17	$311.74	$7.48	$16.71	$1.52	$0.00	$83.21	$49.32	$98.12
8	$367.42	$52.49	4.46%	$35.11	-$4.88	$103.28	$264.14	$6.34	$14.16	$10.42	$0.00	$78.52	$43.19	$98.12
9	$314.93	$52.49	0.00%	$0.00	-$14.75	$88.53	$226.40	$5.43	$12.13	$19.50	$0.00	$74.80	$38.18	$98.12
10	$262.44	$52.49	0.00%	$0.00	-$14.75	$73.77	$188.67	$4.53	$10.11	$18.71	$0.00	$71.08	$33.67	$98.12
11	$209.95	$52.49	0.00%	$0.00	-$14.75	$59.02	$150.94	$3.62	$8.09	$17.92	$0.00	$67.36	$29.61	$98.12
12	$157.47	$52.49	0.00%	$0.00	-$14.75	$44.26	$113.20	$2.72	$6.07	$17.13	$0.00	$63.64	$25.96	$98.12
13	$104.98	$52.49	0.00%	$0.00	-$14.75	$29.51	$75.47	$1.81	$4.04	$16.34	$0.00	$59.93	$22.69	$98.12
14	$52.49	$52.49	0.00%	$0.00	-$14.75	$14.75	$37.73	$0.91	$2.02	$15.55	$0.00	$56.21	$19.75	$98.12
15	$0.00	$52.49	0.00%	$0.00	-$14.75	$0.00	$0.00	$0.00	$0.00	$14.75	$0.00	$52.49	$17.11	$98.12
Total	**$0.0000**	**$787.33**	**100.00%**	**$787.33**	**$0.00**	**$0.00**	**$0.00**	**$108.97**	**$243.42**	**$95.18**	**$85.00**	**$1,319.90**	**$852.41**	**$1,471.84**

Levelized Payment	**$98.12**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$961.83													
1	$897.71	$64.12	14.29%	$137.45	$20.61	$20.61	$877.10	$21.04	$47.01	-$2.23	$85.00	$235.55	$218.59	$117.86
2	$833.59	$64.12	24.49%	$235.55	$48.19	$68.80	$764.79	$18.35	$40.99	-$32.16	$0.00	$139.48	$120.12	$117.86
3	$769.46	$64.12	17.49%	$168.22	$29.26	$98.06	$671.40	$16.11	$35.98	-$15.19	$0.00	$130.28	$104.12	$117.86
4	$705.34	$64.12	12.49%	$120.13	$15.74	$113.81	$591.53	$14.19	$31.70	-$3.35	$0.00	$122.41	$90.79	$117.86
5	$641.22	$64.12	8.93%	$85.89	$6.12	$119.93	$521.29	$12.51	$27.94	$4.80	$0.00	$115.49	$79.49	$117.86
6	$577.10	$64.12	8.92%	$85.80	$6.09	$126.02	$451.08	$10.82	$24.17	$3.36	$0.00	$108.57	$69.34	$117.86
7	$512.98	$64.12	8.93%	$85.89	$6.12	$132.14	$380.84	$9.14	$20.41	$1.86	$0.00	$101.65	$60.25	$117.86
8	$448.85	$64.12	4.46%	$42.90	-$5.97	$126.17	$322.68	$7.74	$17.29	$12.73	$0.00	$95.92	$52.76	$117.86
9	$384.73	$64.12	0.00%	$0.00	-$18.02	$108.15	$276.58	$6.64	$14.82	$23.82	$0.00	$91.38	$46.64	$117.86
10	$320.61	$64.12	0.00%	$0.00	-$18.02	$90.12	$230.49	$5.53	$12.35	$22.85	$0.00	$86.83	$41.13	$117.86
11	$256.49	$64.12	0.00%	$0.00	-$18.02	$72.10	$184.39	$4.42	$9.88	$21.89	$0.00	$82.29	$36.17	$117.86
12	$192.37	$64.12	0.00%	$0.00	-$18.02	$54.07	$138.29	$3.32	$7.41	$20.92	$0.00	$77.75	$31.72	$117.86
13	$128.24	$64.12	0.00%	$0.00	-$18.02	$36.05	$92.19	$2.21	$4.94	$19.96	$0.00	$73.21	$27.71	$117.86
14	$64.12	$64.12	0.00%	$0.00	-$18.02	$18.02	$46.10	$1.11	$2.47	$18.99	$0.00	$68.66	$24.12	$117.86
15	$0.00	$64.12	0.00%	$0.00	-$18.02	$0.00	$0.00	$0.00	$0.00	$18.02	$0.00	$64.12	$20.90	$117.86
Total	**$0.0000**	**$961.83**	**100.00%**	**$961.83**	**$0.00**	**$0.00**	**$0.00**	**$133.12**	**$297.37**	**$116.28**	**$85.00**	**$1,593.60**	**$1,023.86**	**$1,767.87**

Levelized Payment	**$117.86**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

JCP&L LED Street Lighting Monthly Fixture Charge Derivation

Assumption Description	
Book Depreciation Rate	6.67%
Book Life of Investment (yrs)	15.00
Tax Life of Investment (yrs)	7.00
Debt Ratio	47.20%
Equity Ratio	52.80%
Debt Cost	5.083%
Equity Cost	10.15%
Overall Rate of Return (ROR)	7.76%
State Income Tax Rate	9.00%
Federal Income Tax rate	21.00%
Composite Income Tax Rate	28.11%

Summary LED Levelized Monthly Fixture Charge

	Cobra Head 2400 L 30W	Cobra Head 4000 L 50W	Cobra Head 7000 L 90W	Cobra Head 11500 L 130W	Cobra Head 24000 L 260W	Acorn 2500 L 50W	Acorn 5000 L 90W	Colonial 2500 L 50W	Colonial 5000 L 90W
Total Install Costs Per Unit	$ 252.95	$ 252.95	$ 252.95	$ 252.95	$ 252.95	$ 252.95	$ 252.95	$ 252.95	$ 252.95
Total Revenue Requirement	$ 421.11	$ 421.11	$ 421.11	$ 421.11	$ 421.11	$ 421.11	$ 421.11	$ 421.11	$ 421.11
Revenue Requirement NPV	$ 243.89	$ 243.89	$ 243.89	$ 243.89	$ 243.89	$ 243.89	$ 243.89	$ 243.89	$ 243.89
Annual Levelized Payment	$ 28.07	$ 28.07	$ 28.07	$ 28.07	$ 28.07	$ 28.07	$ 28.07	$ 28.07	$ 28.07
Monthly Fixture Charge	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34	$ 2.34
Adjustment for Base Rate Increase	$ 0.40	$ 0.40	$ 0.40	$ 0.40	$ 0.40	$ 0.40	$ 0.40	$ 0.40	$ 0.40
Proposed Monthly Fixture Charge	$ 2.74	$ 2.74	$ 2.74	$ 2.74	$ 2.74	$ 2.74	$ 2.74	$ 2.74	$ 2.74
Proposed Monthly Fixture Charge (Including 6.625% SUT)	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92	$ 2.92

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$167.95													
1	$156.75	$11.20	14.29%	$24.00	$3.60	$3.60	$153.15	$3.67	$8.21	-$0.39	$85.00	$111.29	$103.28	$28.07
2	$145.56	$11.20	24.49%	$41.13	$8.41	$12.01	$133.54	$3.20	$7.16	-$5.62	$0.00	$24.36	$20.97	$28.07
3	$134.36	$11.20	17.49%	$29.37	$5.11	$17.12	$117.24	$2.81	$6.28	-$2.65	$0.00	$22.75	$18.18	$28.07
4	$123.16	$11.20	12.49%	$20.98	$2.75	$19.87	$103.29	$2.48	$5.54	-$0.58	$0.00	$21.37	$15.85	$28.07
5	$111.97	$11.20	8.93%	$15.00	$1.07	$20.94	$91.03	$2.18	$4.88	$0.84	$0.00	$20.17	$13.88	$28.07
6	$100.77	$11.20	8.92%	$14.98	$1.06	$22.00	$78.77	$1.89	$4.22	$0.59	$0.00	$18.96	$12.11	$28.07
7	$89.57	$11.20	8.93%	$15.00	$1.07	$23.07	$66.50	$1.60	$3.56	$0.32	$0.00	$17.75	$10.52	$28.07
8	$78.38	$11.20	4.46%	$7.49	-$1.04	$22.03	$56.34	$1.35	$3.02	$2.22	$0.00	$16.75	$9.21	$28.07
9	$67.18	$11.20	0.00%	$0.00	-$3.15	$18.88	$48.30	$1.16	$2.59	$4.16	$0.00	$15.96	$8.14	$28.07
10	$55.98	$11.20	0.00%	$0.00	-$3.15	$15.74	$40.25	$0.97	$2.16	$3.99	$0.00	$15.16	$7.18	$28.07
11	$44.79	$11.20	0.00%	$0.00	-$3.15	$12.59	$32.20	$0.77	$1.73	$3.82	$0.00	$14.37	$6.32	$28.07
12	$33.59	$11.20	0.00%	$0.00	-$3.15	$9.44	$24.15	$0.58	$1.29	$3.65	$0.00	$13.58	$5.54	$28.07
13	$22.39	$11.20	0.00%	$0.00	-$3.15	$6.29	$16.10	$0.39	$0.86	$3.48	$0.00	$12.78	$4.84	$28.07
14	$11.20	$11.20	0.00%	$0.00	-$3.15	$3.15	$8.05	$0.19	$0.43	$3.32	$0.00	$11.99	$4.21	$28.07
15	$0.00	$11.20	0.00%	$0.00	-$3.15	$0.00	$0.00	$0.00	$0.00	$3.15	$0.00	$11.20	$3.65	$28.07
Total	**$0.00**	**$167.95**	**100.00%**	**$167.95**	**$0.00**	**$0.00**	**$0.00**	**$23.25**	**$51.93**	**$20.30**	**$85.00**	**$348.42**	**$243.89**	**$421.11**

Levelized Payment	**$28.07**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation														
(A)	**(B)**	**(C)**	**(D)**	**(E)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**	**(K)**	**(L)**	**(M)**	**(N)**	**(O)**
	Undepreciated	**Book Depr.**	**Tax Depreciation**		**DIT**		**Rate Base**	**Interest**	**Equity**	**CIT**	**COR**	**Total**	**Present**	**Levelized**
Year	**Balance**	**Expense**	**Rate**	**Expense**	**Expense**	**ADIT**	**Balance**	**Expense**	**Return**	**Expense**	**Expense**	**Charges**	**Value**	**Payment**
0	$167.95													
1	$156.75	$11.20	14.29%	$24.00	$3.60	$3.60	$153.15	$3.67	$8.21	-$0.39	$85.00	$111.29	$103.28	$28.07
2	$145.56	$11.20	24.49%	$41.13	$8.41	$12.01	$133.54	$3.20	$7.16	-$5.62	$0.00	$24.36	$20.97	$28.07
3	$134.36	$11.20	17.49%	$29.37	$5.11	$17.12	$117.24	$2.81	$6.28	-$2.65	$0.00	$22.75	$18.18	$28.07
4	$123.16	$11.20	12.49%	$20.98	$2.75	$19.87	$103.29	$2.48	$5.54	-$0.58	$0.00	$21.37	$15.85	$28.07
5	$111.97	$11.20	8.93%	$15.00	$1.07	$20.94	$91.03	$2.18	$4.88	$0.84	$0.00	$20.17	$13.88	$28.07
6	$100.77	$11.20	8.92%	$14.98	$1.06	$22.00	$78.77	$1.89	$4.22	$0.59	$0.00	$18.96	$12.11	$28.07
7	$89.57	$11.20	8.93%	$15.00	$1.07	$23.07	$66.50	$1.60	$3.56	$0.32	$0.00	$17.75	$10.52	$28.07
8	$78.38	$11.20	4.46%	$7.49	-$1.04	$22.03	$56.34	$1.35	$3.02	$2.22	$0.00	$16.75	$9.21	$28.07
9	$67.18	$11.20	0.00%	$0.00	-$3.15	$18.88	$48.30	$1.16	$2.59	$4.16	$0.00	$15.96	$8.14	$28.07
10	$55.98	$11.20	0.00%	$0.00	-$3.15	$15.74	$40.25	$0.97	$2.16	$3.99	$0.00	$15.16	$7.18	$28.07
11	$44.79	$11.20	0.00%	$0.00	-$3.15	$12.59	$32.20	$0.77	$1.73	$3.82	$0.00	$14.37	$6.32	$28.07
12	$33.59	$11.20	0.00%	$0.00	-$3.15	$9.44	$24.15	$0.58	$1.29	$3.65	$0.00	$13.58	$5.54	$28.07
13	$22.39	$11.20	0.00%	$0.00	-$3.15	$6.29	$16.10	$0.39	$0.86	$3.48	$0.00	$12.78	$4.84	$28.07
14	$11.20	$11.20	0.00%	$0.00	-$3.15	$3.15	$8.05	$0.19	$0.43	$3.32	$0.00	$11.99	$4.21	$28.07
15	$0.00	$11.20	0.00%	$0.00	-$3.15	$0.00	$0.00	$0.00	$0.00	$3.15	$0.00	$11.20	$3.65	$28.07
Total	**$0.00**	**$167.95**	**100.00%**	**$167.95**	**$0.00**	**$0.00**	**$0.00**	**$23.25**	**$51.93**	**$20.30**	**$85.00**	**$348.42**	**$243.89**	**$421.11**

Levelized Payment	**$28.07**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$167.95													
1	$156.75	$11.20	14.29%	$24.00	$3.60	$3.60	$153.15	$3.67	$8.21	-$0.39	$85.00	$111.29	$103.28	$28.07
2	$145.56	$11.20	24.49%	$41.13	$8.41	$12.01	$133.54	$3.20	$7.16	-$5.62	$0.00	$24.36	$20.97	$28.07
3	$134.36	$11.20	17.49%	$29.37	$5.11	$17.12	$117.24	$2.81	$6.28	-$2.65	$0.00	$22.75	$18.18	$28.07
4	$123.16	$11.20	12.49%	$20.98	$2.75	$19.87	$103.29	$2.48	$5.54	-$0.58	$0.00	$21.37	$15.85	$28.07
5	$111.97	$11.20	8.93%	$15.00	$1.07	$20.94	$91.03	$2.18	$4.88	$0.84	$0.00	$20.17	$13.88	$28.07
6	$100.77	$11.20	8.92%	$14.98	$1.06	$22.00	$78.77	$1.89	$4.22	$0.59	$0.00	$18.96	$12.11	$28.07
7	$89.57	$11.20	8.93%	$15.00	$1.07	$23.07	$66.50	$1.60	$3.56	$0.32	$0.00	$17.75	$10.52	$28.07
8	$78.38	$11.20	4.46%	$7.49	-$1.04	$22.03	$56.34	$1.35	$3.02	$2.22	$0.00	$16.75	$9.21	$28.07
9	$67.18	$11.20	0.00%	$0.00	-$3.15	$18.88	$48.30	$1.16	$2.59	$4.16	$0.00	$15.96	$8.14	$28.07
10	$55.98	$11.20	0.00%	$0.00	-$3.15	$15.74	$40.25	$0.97	$2.16	$3.99	$0.00	$15.16	$7.18	$28.07
11	$44.79	$11.20	0.00%	$0.00	-$3.15	$12.59	$32.20	$0.77	$1.73	$3.82	$0.00	$14.37	$6.32	$28.07
12	$33.59	$11.20	0.00%	$0.00	-$3.15	$9.44	$24.15	$0.58	$1.29	$3.65	$0.00	$13.58	$5.54	$28.07
13	$22.39	$11.20	0.00%	$0.00	-$3.15	$6.29	$16.10	$0.39	$0.86	$3.48	$0.00	$12.78	$4.84	$28.07
14	$11.20	$11.20	0.00%	$0.00	-$3.15	$3.15	$8.05	$0.19	$0.43	$3.32	$0.00	$11.99	$4.21	$28.07
15	$0.00	$11.20	0.00%	$0.00	-$3.15	$0.00	$0.00	$0.00	$0.00	$3.15	$0.00	$11.20	$3.65	$28.07
Total	**$0.00**	**$167.95**	**100.00%**	**$167.95**	**$0.00**	**$0.00**	**$0.00**	**$23.25**	**$51.93**	**$20.30**	**$85.00**	**$348.42**	**$243.89**	**$421.11**

Levelized Payment	**$28.07**

Notes:

Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$167.95													
1	$156.75	$11.20	14.29%	$24.00	$3.60	$3.60	$153.15	$3.67	$8.21	-$0.39	$85.00	$111.29	$103.28	$28.07
2	$145.56	$11.20	24.49%	$41.13	$8.41	$12.01	$133.54	$3.20	$7.16	-$5.62	$0.00	$24.36	$20.97	$28.07
3	$134.36	$11.20	17.49%	$29.37	$5.11	$17.12	$117.24	$2.81	$6.28	-$2.65	$0.00	$22.75	$18.18	$28.07
4	$123.16	$11.20	12.49%	$20.98	$2.75	$19.87	$103.29	$2.48	$5.54	-$0.58	$0.00	$21.37	$15.85	$28.07
5	$111.97	$11.20	8.93%	$15.00	$1.07	$20.94	$91.03	$2.18	$4.88	$0.84	$0.00	$20.17	$13.88	$28.07
6	$100.77	$11.20	8.92%	$14.98	$1.06	$22.00	$78.77	$1.89	$4.22	$0.59	$0.00	$18.96	$12.11	$28.07
7	$89.57	$11.20	8.93%	$15.00	$1.07	$23.07	$66.50	$1.60	$3.56	$0.32	$0.00	$17.75	$10.52	$28.07
8	$78.38	$11.20	4.46%	$7.49	-$1.04	$22.03	$56.34	$1.35	$3.02	$2.22	$0.00	$16.75	$9.21	$28.07
9	$67.18	$11.20	0.00%	$0.00	-$3.15	$18.88	$48.30	$1.16	$2.59	$4.16	$0.00	$15.96	$8.14	$28.07
10	$55.98	$11.20	0.00%	$0.00	-$3.15	$15.74	$40.25	$0.97	$2.16	$3.99	$0.00	$15.16	$7.18	$28.07
11	$44.79	$11.20	0.00%	$0.00	-$3.15	$12.59	$32.20	$0.77	$1.73	$3.82	$0.00	$14.37	$6.32	$28.07
12	$33.59	$11.20	0.00%	$0.00	-$3.15	$9.44	$24.15	$0.58	$1.29	$3.65	$0.00	$13.58	$5.54	$28.07
13	$22.39	$11.20	0.00%	$0.00	-$3.15	$6.29	$16.10	$0.39	$0.86	$3.48	$0.00	$12.78	$4.84	$28.07
14	$11.20	$11.20	0.00%	$0.00	-$3.15	$3.15	$8.05	$0.19	$0.43	$3.32	$0.00	$11.99	$4.21	$28.07
15	$0.00	$11.20	0.00%	$0.00	-$3.15	$0.00	$0.00	$0.00	$0.00	$3.15	$0.00	$11.20	$3.65	$28.07
Total	**$0.00**	**$167.95**	**100.00%**	**$167.95**	**$0.00**	**$0.00**	**$0.00**	**$23.25**	**$51.93**	**$20.30**	**$85.00**	**$348.42**	**$243.89**	**$421.11**

Levelized Payment	**$28.07**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$167.95													
1	$156.75	$11.20	14.29%	$24.00	$3.60	$3.60	$153.15	$3.67	$8.21	-$0.39	$85.00	$111.29	$103.28	$28.07
2	$145.56	$11.20	24.49%	$41.13	$8.41	$12.01	$133.54	$3.20	$7.16	-$5.62	$0.00	$24.36	$20.97	$28.07
3	$134.36	$11.20	17.49%	$29.37	$5.11	$17.12	$117.24	$2.81	$6.28	-$2.65	$0.00	$22.75	$18.18	$28.07
4	$123.16	$11.20	12.49%	$20.98	$2.75	$19.87	$103.29	$2.48	$5.54	-$0.58	$0.00	$21.37	$15.85	$28.07
5	$111.97	$11.20	8.93%	$15.00	$1.07	$20.94	$91.03	$2.18	$4.88	$0.84	$0.00	$20.17	$13.88	$28.07
6	$100.77	$11.20	8.92%	$14.98	$1.06	$22.00	$78.77	$1.89	$4.22	$0.59	$0.00	$18.96	$12.11	$28.07
7	$89.57	$11.20	8.93%	$15.00	$1.07	$23.07	$66.50	$1.60	$3.56	$0.32	$0.00	$17.75	$10.52	$28.07
8	$78.38	$11.20	4.46%	$7.49	-$1.04	$22.03	$56.34	$1.35	$3.02	$2.22	$0.00	$16.75	$9.21	$28.07
9	$67.18	$11.20	0.00%	$0.00	-$3.15	$18.88	$48.30	$1.16	$2.59	$4.16	$0.00	$15.96	$8.14	$28.07
10	$55.98	$11.20	0.00%	$0.00	-$3.15	$15.74	$40.25	$0.97	$2.16	$3.99	$0.00	$15.16	$7.18	$28.07
11	$44.79	$11.20	0.00%	$0.00	-$3.15	$12.59	$32.20	$0.77	$1.73	$3.82	$0.00	$14.37	$6.32	$28.07
12	$33.59	$11.20	0.00%	$0.00	-$3.15	$9.44	$24.15	$0.58	$1.29	$3.65	$0.00	$13.58	$5.54	$28.07
13	$22.39	$11.20	0.00%	$0.00	-$3.15	$6.29	$16.10	$0.39	$0.86	$3.48	$0.00	$12.78	$4.84	$28.07
14	$11.20	$11.20	0.00%	$0.00	-$3.15	$3.15	$8.05	$0.19	$0.43	$3.32	$0.00	$11.99	$4.21	$28.07
15	$0.00	$11.20	0.00%	$0.00	-$3.15	$0.00	$0.00	$0.00	$0.00	$3.15	$0.00	$11.20	$3.65	$28.07
Total	**$0.00**	**$167.95**	**100.00%**	**$167.95**	**$0.00**	**$0.00**	**$0.00**	**$23.25**	**$51.93**	**$20.30**	**$85.00**	**$348.42**	**$243.89**	**$421.11**

Levelized Payment	**$28.07**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$167.95													
1	$156.75	$11.20	14.29%	$24.00	$3.60	$3.60	$153.15	$3.67	$8.21	-$0.39	$85.00	$111.29	$103.28	$28.07
2	$145.56	$11.20	24.49%	$41.13	$8.41	$12.01	$133.54	$3.20	$7.16	-$5.62	$0.00	$24.36	$20.97	$28.07
3	$134.36	$11.20	17.49%	$29.37	$5.11	$17.12	$117.24	$2.81	$6.28	-$2.65	$0.00	$22.75	$18.18	$28.07
4	$123.16	$11.20	12.49%	$20.98	$2.75	$19.87	$103.29	$2.48	$5.54	-$0.58	$0.00	$21.37	$15.85	$28.07
5	$111.97	$11.20	8.93%	$15.00	$1.07	$20.94	$91.03	$2.18	$4.88	$0.84	$0.00	$20.17	$13.88	$28.07
6	$100.77	$11.20	8.92%	$14.98	$1.06	$22.00	$78.77	$1.89	$4.22	$0.59	$0.00	$18.96	$12.11	$28.07
7	$89.57	$11.20	8.93%	$15.00	$1.07	$23.07	$66.50	$1.60	$3.56	$0.32	$0.00	$17.75	$10.52	$28.07
8	$78.38	$11.20	4.46%	$7.49	-$1.04	$22.03	$56.34	$1.35	$3.02	$2.22	$0.00	$16.75	$9.21	$28.07
9	$67.18	$11.20	0.00%	$0.00	-$3.15	$18.88	$48.30	$1.16	$2.59	$4.16	$0.00	$15.96	$8.14	$28.07
10	$55.98	$11.20	0.00%	$0.00	-$3.15	$15.74	$40.25	$0.97	$2.16	$3.99	$0.00	$15.16	$7.18	$28.07
11	$44.79	$11.20	0.00%	$0.00	-$3.15	$12.59	$32.20	$0.77	$1.73	$3.82	$0.00	$14.37	$6.32	$28.07
12	$33.59	$11.20	0.00%	$0.00	-$3.15	$9.44	$24.15	$0.58	$1.29	$3.65	$0.00	$13.58	$5.54	$28.07
13	$22.39	$11.20	0.00%	$0.00	-$3.15	$6.29	$16.10	$0.39	$0.86	$3.48	$0.00	$12.78	$4.84	$28.07
14	$11.20	$11.20	0.00%	$0.00	-$3.15	$3.15	$8.05	$0.19	$0.43	$3.32	$0.00	$11.99	$4.21	$28.07
15	$0.00	$11.20	0.00%	$0.00	-$3.15	$0.00	$0.00	$0.00	$0.00	$3.15	$0.00	$11.20	$3.65	$28.07
Total	**$0.00**	**$167.95**	**100.00%**	**$167.95**	**$0.00**	**$0.00**	**$0.00**	**$23.25**	**$51.93**	**$20.30**	**$85.00**	**$348.42**	**$243.89**	**$421.11**

Levelized Payment	**$28.07**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$167.95													
1	$156.75	$11.20	14.29%	$24.00	$3.60	$3.60	$153.15	$3.67	$8.21	-$0.39	$85.00	$111.29	$103.28	$28.07
2	$145.56	$11.20	24.49%	$41.13	$8.41	$12.01	$133.54	$3.20	$7.16	-$5.62	$0.00	$24.36	$20.97	$28.07
3	$134.36	$11.20	17.49%	$29.37	$5.11	$17.12	$117.24	$2.81	$6.28	-$2.65	$0.00	$22.75	$18.18	$28.07
4	$123.16	$11.20	12.49%	$20.98	$2.75	$19.87	$103.29	$2.48	$5.54	-$0.58	$0.00	$21.37	$15.85	$28.07
5	$111.97	$11.20	8.93%	$15.00	$1.07	$20.94	$91.03	$2.18	$4.88	$0.84	$0.00	$20.17	$13.88	$28.07
6	$100.77	$11.20	8.92%	$14.98	$1.06	$22.00	$78.77	$1.89	$4.22	$0.59	$0.00	$18.96	$12.11	$28.07
7	$89.57	$11.20	8.93%	$15.00	$1.07	$23.07	$66.50	$1.60	$3.56	$0.32	$0.00	$17.75	$10.52	$28.07
8	$78.38	$11.20	4.46%	$7.49	-$1.04	$22.03	$56.34	$1.35	$3.02	$2.22	$0.00	$16.75	$9.21	$28.07
9	$67.18	$11.20	0.00%	$0.00	-$3.15	$18.88	$48.30	$1.16	$2.59	$4.16	$0.00	$15.96	$8.14	$28.07
10	$55.98	$11.20	0.00%	$0.00	-$3.15	$15.74	$40.25	$0.97	$2.16	$3.99	$0.00	$15.16	$7.18	$28.07
11	$44.79	$11.20	0.00%	$0.00	-$3.15	$12.59	$32.20	$0.77	$1.73	$3.82	$0.00	$14.37	$6.32	$28.07
12	$33.59	$11.20	0.00%	$0.00	-$3.15	$9.44	$24.15	$0.58	$1.29	$3.65	$0.00	$13.58	$5.54	$28.07
13	$22.39	$11.20	0.00%	$0.00	-$3.15	$6.29	$16.10	$0.39	$0.86	$3.48	$0.00	$12.78	$4.84	$28.07
14	$11.20	$11.20	0.00%	$0.00	-$3.15	$3.15	$8.05	$0.19	$0.43	$3.32	$0.00	$11.99	$4.21	$28.07
15	$0.00	$11.20	0.00%	$0.00	-$3.15	$0.00	$0.00	$0.00	$0.00	$3.15	$0.00	$11.20	$3.65	$28.07
Total	**$0.00**	**$167.95**	**100.00%**	**$167.95**	**$0.00**	**$0.00**	**$0.00**	**$23.25**	**$51.93**	**$20.30**	**$85.00**	**$348.42**	**$243.89**	**$421.11**

Levelized Payment	$28.07

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$167.95													
1	$156.75	$11.20	14.29%	$24.00	$3.60	$3.60	$153.15	$3.67	$8.21	-$0.39	$85.00	$111.29	$103.28	$28.07
2	$145.56	$11.20	24.49%	$41.13	$8.41	$12.01	$133.54	$3.20	$7.16	-$5.62	$0.00	$24.36	$20.97	$28.07
3	$134.36	$11.20	17.49%	$29.37	$5.11	$17.12	$117.24	$2.81	$6.28	-$2.65	$0.00	$22.75	$18.18	$28.07
4	$123.16	$11.20	12.49%	$20.98	$2.75	$19.87	$103.29	$2.48	$5.54	-$0.58	$0.00	$21.37	$15.85	$28.07
5	$111.97	$11.20	8.93%	$15.00	$1.07	$20.94	$91.03	$2.18	$4.88	$0.84	$0.00	$20.17	$13.88	$28.07
6	$100.77	$11.20	8.92%	$14.98	$1.06	$22.00	$78.77	$1.89	$4.22	$0.59	$0.00	$18.96	$12.11	$28.07
7	$89.57	$11.20	8.93%	$15.00	$1.07	$23.07	$66.50	$1.60	$3.56	$0.32	$0.00	$17.75	$10.52	$28.07
8	$78.38	$11.20	4.46%	$7.49	-$1.04	$22.03	$56.34	$1.35	$3.02	$2.22	$0.00	$16.75	$9.21	$28.07
9	$67.18	$11.20	0.00%	$0.00	-$3.15	$18.88	$48.30	$1.16	$2.59	$4.16	$0.00	$15.96	$8.14	$28.07
10	$55.98	$11.20	0.00%	$0.00	-$3.15	$15.74	$40.25	$0.97	$2.16	$3.99	$0.00	$15.16	$7.18	$28.07
11	$44.79	$11.20	0.00%	$0.00	-$3.15	$12.59	$32.20	$0.77	$1.73	$3.82	$0.00	$14.37	$6.32	$28.07
12	$33.59	$11.20	0.00%	$0.00	-$3.15	$9.44	$24.15	$0.58	$1.29	$3.65	$0.00	$13.58	$5.54	$28.07
13	$22.39	$11.20	0.00%	$0.00	-$3.15	$6.29	$16.10	$0.39	$0.86	$3.48	$0.00	$12.78	$4.84	$28.07
14	$11.20	$11.20	0.00%	$0.00	-$3.15	$3.15	$8.05	$0.19	$0.43	$3.32	$0.00	$11.99	$4.21	$28.07
15	$0.00	$11.20	0.00%	$0.00	-$3.15	$0.00	$0.00	$0.00	$0.00	$3.15	$0.00	$11.20	$3.65	$28.07
Total	**$0.0000**	**$167.95**	**100.00%**	**$167.95**	**$0.00**	**$0.00**	**$0.00**	**$23.25**	**$51.93**	**$20.30**	**$85.00**	**$348.42**	**$243.89**	**$421.11**

Levelized Payment	**$28.07**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$167.95													
1	$156.75	$11.20	14.29%	$24.00	$3.60	$3.60	$153.15	$3.67	$8.21	-$0.39	$85.00	$111.29	$103.28	$28.07
2	$145.56	$11.20	24.49%	$41.13	$8.41	$12.01	$133.54	$3.20	$7.16	-$5.62	$0.00	$24.36	$20.97	$28.07
3	$134.36	$11.20	17.49%	$29.37	$5.11	$17.12	$117.24	$2.81	$6.28	-$2.65	$0.00	$22.75	$18.18	$28.07
4	$123.16	$11.20	12.49%	$20.98	$2.75	$19.87	$103.29	$2.48	$5.54	-$0.58	$0.00	$21.37	$15.85	$28.07
5	$111.97	$11.20	8.93%	$15.00	$1.07	$20.94	$91.03	$2.18	$4.88	$0.84	$0.00	$20.17	$13.88	$28.07
6	$100.77	$11.20	8.92%	$14.98	$1.06	$22.00	$78.77	$1.89	$4.22	$0.59	$0.00	$18.96	$12.11	$28.07
7	$89.57	$11.20	8.93%	$15.00	$1.07	$23.07	$66.50	$1.60	$3.56	$0.32	$0.00	$17.75	$10.52	$28.07
8	$78.38	$11.20	4.46%	$7.49	-$1.04	$22.03	$56.34	$1.35	$3.02	$2.22	$0.00	$16.75	$9.21	$28.07
9	$67.18	$11.20	0.00%	$0.00	-$3.15	$18.88	$48.30	$1.16	$2.59	$4.16	$0.00	$15.96	$8.14	$28.07
10	$55.98	$11.20	0.00%	$0.00	-$3.15	$15.74	$40.25	$0.97	$2.16	$3.99	$0.00	$15.16	$7.18	$28.07
11	$44.79	$11.20	0.00%	$0.00	-$3.15	$12.59	$32.20	$0.77	$1.73	$3.82	$0.00	$14.37	$6.32	$28.07
12	$33.59	$11.20	0.00%	$0.00	-$3.15	$9.44	$24.15	$0.58	$1.29	$3.65	$0.00	$13.58	$5.54	$28.07
13	$22.39	$11.20	0.00%	$0.00	-$3.15	$6.29	$16.10	$0.39	$0.86	$3.48	$0.00	$12.78	$4.84	$28.07
14	$11.20	$11.20	0.00%	$0.00	-$3.15	$3.15	$8.05	$0.19	$0.43	$3.32	$0.00	$11.99	$4.21	$28.07
15	$0.00	$11.20	0.00%	$0.00	-$3.15	$0.00	$0.00	$0.00	$0.00	$3.15	$0.00	$11.20	$3.65	$28.07
Total	**$0.0000**	**$167.95**	**100.00%**	**$167.95**	**$0.00**	**$0.00**	**$0.00**	**$23.25**	**$51.93**	**$20.30**	**$85.00**	**$348.42**	**$243.89**	**$421.11**

Levelized Payment	**$28.07**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

JCP&L LED Street Lighting Monthly Fixture Charge Derivation

Assumption Description	
Book Depreciation Rate	6.67%
Book Life of Investment (yrs)	15.00
Tax Life of Investment (yrs)	7.00
Debt Ratio	47.20%
Equity Ratio	52.80%
Debt Cost	5.083%
Equity Cost	10.15%
Overall Rate of Return (ROR)	7.76%
State Income Tax Rate	9.00%
Federal Income Tax rate	21.00%
Composite Income Tax Rate	28.11%

Summary LED Levelized Monthly Fixture Charge

	Cobra Head 2400 L 30W	Cobra Head 4000 L 50W	Cobra Head 7000 L 90W	Cobra Head 11500 L 130W	Cobra Head 24000 L 260W	Acorn 2500 L 50W	Acorn 5000 L 90W	Colonial 2500 L 50W	Colonial 5000 L 90W
Total Install Costs Per Unit	$ 402.13	$ 402.13	$ 402.13	$ 402.13	$ 402.13	$ 402.13	$ 402.13	$ 402.13	$ 402.13
Total Revenue Requirement	$ 674.19	$ 674.19	$ 674.19	$ 674.19	$ 674.19	$ 674.19	$ 674.19	$ 674.19	$ 674.19
Revenue Requirement NPV	$ 390.45	$ 390.45	$ 390.45	$ 390.45	$ 390.45	$ 390.45	$ 390.45	$ 390.45	$ 390.45
Annual Levelized Payment	$ 44.95	$ 44.95	$ 44.95	$ 44.95	$ 44.95	$ 44.95	$ 44.95	$ 44.95	$ 44.95
Monthly Fixture Charge	$ 3.75	$ 3.75	$ 3.75	$ 3.75	$ 3.75	$ 3.75	$ 3.75	$ 3.75	$ 3.75
Adjustment for Base Rate Increase	$ 0.64	$ 0.64	$ 0.64	$ 0.64	$ 0.64	$ 0.64	$ 0.64	$ 0.64	$ 0.64
Proposed Monthly Fixture Charge	$ 4.39	$ 4.39	$ 4.39	$ 4.39	$ 4.39	$ 4.39	$ 4.39	$ 4.39	$ 4.39
Proposed Monthly Fixture Charge (Including 6.625% SUT)	$ 4.68	$ 4.68	$ 4.68	$ 4.68	$ 4.68	$ 4.68	$ 4.68	$ 4.68	$ 4.68

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$317.13													
1	$295.99	$21.14	14.29%	$45.32	$6.80	$6.80	$289.19	$6.94	$15.50	-$0.74	$85.00	$134.64	$124.94	$44.95
2	$274.85	$21.14	24.49%	$77.67	$15.89	$22.68	$252.16	$6.05	$13.51	-$10.60	$0.00	$45.99	$39.61	$44.95
3	$253.70	$21.14	17.49%	$55.47	$9.65	$32.33	$221.37	$5.31	$11.86	-$5.01	$0.00	$42.96	$34.33	$44.95
4	$232.56	$21.14	12.49%	$39.61	$5.19	$37.52	$195.04	$4.68	$10.45	-$1.10	$0.00	$40.36	$29.93	$44.95
5	$211.42	$21.14	8.93%	$28.32	$2.02	$39.54	$171.88	$4.12	$9.21	$1.58	$0.00	$38.08	$26.21	$44.95
6	$190.28	$21.14	8.92%	$28.29	$2.01	$41.55	$148.73	$3.57	$7.97	$1.11	$0.00	$35.80	$22.86	$44.95
7	$169.14	$21.14	8.93%	$28.32	$2.02	$43.57	$125.57	$3.01	$6.73	$0.61	$0.00	$33.52	$19.86	$44.95
8	$147.99	$21.14	4.46%	$14.14	-$1.97	$41.60	$106.39	$2.55	$5.70	$4.20	$0.00	$31.63	$17.40	$44.95
9	$126.85	$21.14	0.00%	$0.00	-$5.94	$35.66	$91.19	$2.19	$4.89	$7.85	$0.00	$30.13	$15.38	$44.95
10	$105.71	$21.14	0.00%	$0.00	-$5.94	$29.72	$75.99	$1.82	$4.07	$7.54	$0.00	$28.63	$13.56	$44.95
11	$84.57	$21.14	0.00%	$0.00	-$5.94	$23.77	$60.80	$1.46	$3.26	$7.22	$0.00	$27.13	$11.93	$44.95
12	$63.43	$21.14	0.00%	$0.00	-$5.94	$17.83	$45.60	$1.09	$2.44	$6.90	$0.00	$25.64	$10.46	$44.95
13	$42.28	$21.14	0.00%	$0.00	-$5.94	$11.89	$30.40	$0.73	$1.63	$6.58	$0.00	$24.14	$9.14	$44.95
14	$21.14	$21.14	0.00%	$0.00	-$5.94	$5.94	$15.20	$0.36	$0.81	$6.26	$0.00	$22.64	$7.95	$44.95
15	$0.00	$21.14	0.00%	$0.00	-$5.94	$0.00	$0.00	$0.00	$0.00	$5.94	$0.00	$21.14	$6.89	$44.95
Total	**$0.00**	**$317.13**	**100.00%**	**$317.13**	**$0.00**	**$0.00**	**$0.00**	**$43.89**	**$98.05**	**$38.34**	**$85.00**	**$582.41**	**$390.45**	**$674.19**

Levelized Payment	**$44.95**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$317.13													
1	$295.99	$21.14	14.29%	$45.32	$6.80	$6.80	$289.19	$6.94	$15.50	-$0.74	$85.00	$134.64	$124.94	$44.95
2	$274.85	$21.14	24.49%	$77.67	$15.89	$22.68	$252.16	$6.05	$13.51	-$10.60	$0.00	$45.99	$39.61	$44.95
3	$253.70	$21.14	17.49%	$55.47	$9.65	$32.33	$221.37	$5.31	$11.86	-$5.01	$0.00	$42.96	$34.33	$44.95
4	$232.56	$21.14	12.49%	$39.61	$5.19	$37.52	$195.04	$4.68	$10.45	-$1.10	$0.00	$40.36	$29.93	$44.95
5	$211.42	$21.14	8.93%	$28.32	$2.02	$39.54	$171.88	$4.12	$9.21	$1.58	$0.00	$38.08	$26.21	$44.95
6	$190.28	$21.14	8.92%	$28.29	$2.01	$41.55	$148.73	$3.57	$7.97	$1.11	$0.00	$35.80	$22.86	$44.95
7	$169.14	$21.14	8.93%	$28.32	$2.02	$43.57	$125.57	$3.01	$6.73	$0.61	$0.00	$33.52	$19.86	$44.95
8	$147.99	$21.14	4.46%	$14.14	-$1.97	$41.60	$106.39	$2.55	$5.70	$4.20	$0.00	$31.63	$17.40	$44.95
9	$126.85	$21.14	0.00%	$0.00	-$5.94	$35.66	$91.19	$2.19	$4.89	$7.85	$0.00	$30.13	$15.38	$44.95
10	$105.71	$21.14	0.00%	$0.00	-$5.94	$29.72	$75.99	$1.82	$4.07	$7.54	$0.00	$28.63	$13.56	$44.95
11	$84.57	$21.14	0.00%	$0.00	-$5.94	$23.77	$60.80	$1.46	$3.26	$7.22	$0.00	$27.13	$11.93	$44.95
12	$63.43	$21.14	0.00%	$0.00	-$5.94	$17.83	$45.60	$1.09	$2.44	$6.90	$0.00	$25.64	$10.46	$44.95
13	$42.28	$21.14	0.00%	$0.00	-$5.94	$11.89	$30.40	$0.73	$1.63	$6.58	$0.00	$24.14	$9.14	$44.95
14	$21.14	$21.14	0.00%	$0.00	-$5.94	$5.94	$15.20	$0.36	$0.81	$6.26	$0.00	$22.64	$7.95	$44.95
15	$0.00	$21.14	0.00%	$0.00	-$5.94	$0.00	$0.00	$0.00	$0.00	$5.94	$0.00	$21.14	$6.89	$44.95
Total	**$0.00**	**$317.13**	**100.00%**	**$317.13**	**$0.00**	**$0.00**	**$0.00**	**$43.89**	**$98.05**	**$38.34**	**$85.00**	**$582.41**	**$390.45**	**$674.19**

Levelized Payment	**$44.95**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$317.13													
1	$295.99	$21.14	14.29%	$45.32	$6.80	$6.80	$289.19	$6.94	$15.50	-$0.74	$85.00	$134.64	$124.94	$44.95
2	$274.85	$21.14	24.49%	$77.67	$15.89	$22.68	$252.16	$6.05	$13.51	-$10.60	$0.00	$45.99	$39.61	$44.95
3	$253.70	$21.14	17.49%	$55.47	$9.65	$32.33	$221.37	$5.31	$11.86	-$5.01	$0.00	$42.96	$34.33	$44.95
4	$232.56	$21.14	12.49%	$39.61	$5.19	$37.52	$195.04	$4.68	$10.45	-$1.10	$0.00	$40.36	$29.93	$44.95
5	$211.42	$21.14	8.93%	$28.32	$2.02	$39.54	$171.88	$4.12	$9.21	$1.58	$0.00	$38.08	$26.21	$44.95
6	$190.28	$21.14	8.92%	$28.29	$2.01	$41.55	$148.73	$3.57	$7.97	$1.11	$0.00	$35.80	$22.86	$44.95
7	$169.14	$21.14	8.93%	$28.32	$2.02	$43.57	$125.57	$3.01	$6.73	$0.61	$0.00	$33.52	$19.86	$44.95
8	$147.99	$21.14	4.46%	$14.14	-$1.97	$41.60	$106.39	$2.55	$5.70	$4.20	$0.00	$31.63	$17.40	$44.95
9	$126.85	$21.14	0.00%	$0.00	-$5.94	$35.66	$91.19	$2.19	$4.89	$7.85	$0.00	$30.13	$15.38	$44.95
10	$105.71	$21.14	0.00%	$0.00	-$5.94	$29.72	$75.99	$1.82	$4.07	$7.54	$0.00	$28.63	$13.56	$44.95
11	$84.57	$21.14	0.00%	$0.00	-$5.94	$23.77	$60.80	$1.46	$3.26	$7.22	$0.00	$27.13	$11.93	$44.95
12	$63.43	$21.14	0.00%	$0.00	-$5.94	$17.83	$45.60	$1.09	$2.44	$6.90	$0.00	$25.64	$10.46	$44.95
13	$42.28	$21.14	0.00%	$0.00	-$5.94	$11.89	$30.40	$0.73	$1.63	$6.58	$0.00	$24.14	$9.14	$44.95
14	$21.14	$21.14	0.00%	$0.00	-$5.94	$5.94	$15.20	$0.36	$0.81	$6.26	$0.00	$22.64	$7.95	$44.95
15	$0.00	$21.14	0.00%	$0.00	-$5.94	$0.00	$0.00	$0.00	$0.00	$5.94	$0.00	$21.14	$6.89	$44.95
Total	**$0.00**	**$317.13**	**100.00%**	**$317.13**	**$0.00**	**$0.00**	**$0.00**	**$43.89**	**$98.05**	**$38.34**	**$85.00**	**$582.41**	**$390.45**	**$674.19**

Levelized Payment	**$44.95**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$317.13													
1	$295.99	$21.14	14.29%	$45.32	$6.80	$6.80	$289.19	$6.94	$15.50	-$0.74	$85.00	$134.64	$124.94	$44.95
2	$274.85	$21.14	24.49%	$77.67	$15.89	$22.68	$252.16	$6.05	$13.51	-$10.60	$0.00	$45.99	$39.61	$44.95
3	$253.70	$21.14	17.49%	$55.47	$9.65	$32.33	$221.37	$5.31	$11.86	-$5.01	$0.00	$42.96	$34.33	$44.95
4	$232.56	$21.14	12.49%	$39.61	$5.19	$37.52	$195.04	$4.68	$10.45	-$1.10	$0.00	$40.36	$29.93	$44.95
5	$211.42	$21.14	8.93%	$28.32	$2.02	$39.54	$171.88	$4.12	$9.21	$1.58	$0.00	$38.08	$26.21	$44.95
6	$190.28	$21.14	8.92%	$28.29	$2.01	$41.55	$148.73	$3.57	$7.97	$1.11	$0.00	$35.80	$22.86	$44.95
7	$169.14	$21.14	8.93%	$28.32	$2.02	$43.57	$125.57	$3.01	$6.73	$0.61	$0.00	$33.52	$19.86	$44.95
8	$147.99	$21.14	4.46%	$14.14	-$1.97	$41.60	$106.39	$2.55	$5.70	$4.20	$0.00	$31.63	$17.40	$44.95
9	$126.85	$21.14	0.00%	$0.00	-$5.94	$35.66	$91.19	$2.19	$4.89	$7.85	$0.00	$30.13	$15.38	$44.95
10	$105.71	$21.14	0.00%	$0.00	-$5.94	$29.72	$75.99	$1.82	$4.07	$7.54	$0.00	$28.63	$13.56	$44.95
11	$84.57	$21.14	0.00%	$0.00	-$5.94	$23.77	$60.80	$1.46	$3.26	$7.22	$0.00	$27.13	$11.93	$44.95
12	$63.43	$21.14	0.00%	$0.00	-$5.94	$17.83	$45.60	$1.09	$2.44	$6.90	$0.00	$25.64	$10.46	$44.95
13	$42.28	$21.14	0.00%	$0.00	-$5.94	$11.89	$30.40	$0.73	$1.63	$6.58	$0.00	$24.14	$9.14	$44.95
14	$21.14	$21.14	0.00%	$0.00	-$5.94	$5.94	$15.20	$0.36	$0.81	$6.26	$0.00	$22.64	$7.95	$44.95
15	$0.00	$21.14	0.00%	$0.00	-$5.94	$0.00	$0.00	$0.00	$0.00	$5.94	$0.00	$21.14	$6.89	$44.95
Total	**$0.00**	**$317.13**	**100.00%**	**$317.13**	**$0.00**	**$0.00**	**$0.00**	**$43.89**	**$98.05**	**$38.34**	**$85.00**	**$582.41**	**$390.45**	**$674.19**

Levelized Payment	**$44.95**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
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Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$317.13													
1	$295.99	$21.14	14.29%	$45.32	$6.80	$6.80	$289.19	$6.94	$15.50	-$0.74	$85.00	$134.64	$124.94	$44.95
2	$274.85	$21.14	24.49%	$77.67	$15.89	$22.68	$252.16	$6.05	$13.51	-$10.60	$0.00	$45.99	$39.61	$44.95
3	$253.70	$21.14	17.49%	$55.47	$9.65	$32.33	$221.37	$5.31	$11.86	-$5.01	$0.00	$42.96	$34.33	$44.95
4	$232.56	$21.14	12.49%	$39.61	$5.19	$37.52	$195.04	$4.68	$10.45	-$1.10	$0.00	$40.36	$29.93	$44.95
5	$211.42	$21.14	8.93%	$28.32	$2.02	$39.54	$171.88	$4.12	$9.21	$1.58	$0.00	$38.08	$26.21	$44.95
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10	$105.71	$21.14	0.00%	$0.00	-$5.94	$29.72	$75.99	$1.82	$4.07	$7.54	$0.00	$28.63	$13.56	$44.95
11	$84.57	$21.14	0.00%	$0.00	-$5.94	$23.77	$60.80	$1.46	$3.26	$7.22	$0.00	$27.13	$11.93	$44.95
12	$63.43	$21.14	0.00%	$0.00	-$5.94	$17.83	$45.60	$1.09	$2.44	$6.90	$0.00	$25.64	$10.46	$44.95
13	$42.28	$21.14	0.00%	$0.00	-$5.94	$11.89	$30.40	$0.73	$1.63	$6.58	$0.00	$24.14	$9.14	$44.95
14	$21.14	$21.14	0.00%	$0.00	-$5.94	$5.94	$15.20	$0.36	$0.81	$6.26	$0.00	$22.64	$7.95	$44.95
15	$0.00	$21.14	0.00%	$0.00	-$5.94	$0.00	$0.00	$0.00	$0.00	$5.94	$0.00	$21.14	$6.89	$44.95
Total	**$0.00**	**$317.13**	**100.00%**	**$317.13**	**$0.00**	**$0.00**	**$0.00**	**$43.89**	**$98.05**	**$38.34**	**$85.00**	**$582.41**	**$390.45**	**$674.19**

Levelized Payment	**$44.95**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
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Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$317.13													
1	$295.99	$21.14	14.29%	$45.32	$6.80	$6.80	$289.19	$6.94	$15.50	-$0.74	$85.00	$134.64	$124.94	$44.95
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15	$0.00	$21.14	0.00%	$0.00	-$5.94	$0.00	$0.00	$0.00	$0.00	$5.94	$0.00	$21.14	$6.89	$44.95
Total	**$0.00**	**$317.13**	**100.00%**	**$317.13**	**$0.00**	**$0.00**	**$0.00**	**$43.89**	**$98.05**	**$38.34**	**$85.00**	**$582.41**	**$390.45**	**$674.19**

Levelized Payment	**$44.95**

Notes:
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LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
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15	$0.00	$21.14	0.00%	$0.00	-$5.94	$0.00	$0.00	$0.00	$0.00	$5.94	$0.00	$21.14	$6.89	$44.95
Total	**$0.00**	**$317.13**	**100.00%**	**$317.13**	**$0.00**	**$0.00**	**$0.00**	**$43.89**	**$98.05**	**$38.34**	**$85.00**	**$582.41**	**$390.45**	**$674.19**

Levelized Payment	**$44.95**

Notes:
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LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
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11	$84.57	$21.14	0.00%	$0.00	-$5.94	$23.77	$60.80	$1.46	$3.26	$7.22	$0.00	$27.13	$11.93	$44.95
12	$63.43	$21.14	0.00%	$0.00	-$5.94	$17.83	$45.60	$1.09	$2.44	$6.90	$0.00	$25.64	$10.46	$44.95
13	$42.28	$21.14	0.00%	$0.00	-$5.94	$11.89	$30.40	$0.73	$1.63	$6.58	$0.00	$24.14	$9.14	$44.95
14	$21.14	$21.14	0.00%	$0.00	-$5.94	$5.94	$15.20	$0.36	$0.81	$6.26	$0.00	$22.64	$7.95	$44.95
15	$0.00	$21.14	0.00%	$0.00	-$5.94	$0.00	$0.00	$0.00	$0.00	$5.94	$0.00	$21.14	$6.89	$44.95
Total	**$0.0000**	**$317.13**	**100.00%**	**$317.13**	**$0.00**	**$0.00**	**$0.00**	**$43.89**	**$98.05**	**$38.34**	**$85.00**	**$582.41**	**$390.45**	**$674.19**

Levelized Payment	**$44.95**

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
Column (E) = Column (D) X Beg. Bal. Column (B)
Column (F) = (Column (E) - Column (C)) X Composite Income Tax Rate
Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

LED Street Lighting Levelized Fixture Charge Calculation

(A) Year	(B) Undepreciated Balance	(C) Book Depr. Expense	(D) Tax Depreciation Rate	(E) Tax Depreciation Expense	(F) DIT Expense	(G) ADIT	(H) Rate Base Balance	(I) Interest Expense	(J) Equity Return	(K) CIT Expense	(L) COR Expense	(M) Total Charges	(N) Present Value	(O) Levelized Payment
0	$317.13													
1	$295.99	$21.14	14.29%	$45.32	$6.80	$6.80	$289.19	$6.94	$15.50	-$0.74	$85.00	$134.64	$124.94	$44.95
2	$274.85	$21.14	24.49%	$77.67	$15.89	$22.68	$252.16	$6.05	$13.51	-$10.60	$0.00	$45.99	$39.61	$44.95
3	$253.70	$21.14	17.49%	$55.47	$9.65	$32.33	$221.37	$5.31	$11.86	-$5.01	$0.00	$42.96	$34.33	$44.95
4	$232.56	$21.14	12.49%	$39.61	$5.19	$37.52	$195.04	$4.68	$10.45	-$1.10	$0.00	$40.36	$29.93	$44.95
5	$211.42	$21.14	8.93%	$28.32	$2.02	$39.54	$171.88	$4.12	$9.21	$1.58	$0.00	$38.08	$26.21	$44.95
6	$190.28	$21.14	8.92%	$28.29	$2.01	$41.55	$148.73	$3.57	$7.97	$1.11	$0.00	$35.80	$22.86	$44.95
7	$169.14	$21.14	8.93%	$28.32	$2.02	$43.57	$125.57	$3.01	$6.73	$0.61	$0.00	$33.52	$19.86	$44.95
8	$147.99	$21.14	4.46%	$14.14	-$1.97	$41.60	$106.39	$2.55	$5.70	$4.20	$0.00	$31.63	$17.40	$44.95
9	$126.85	$21.14	0.00%	$0.00	-$5.94	$35.66	$91.19	$2.19	$4.89	$7.85	$0.00	$30.13	$15.38	$44.95
10	$105.71	$21.14	0.00%	$0.00	-$5.94	$29.72	$75.99	$1.82	$4.07	$7.54	$0.00	$28.63	$13.56	$44.95
11	$84.57	$21.14	0.00%	$0.00	-$5.94	$23.77	$60.80	$1.46	$3.26	$7.22	$0.00	$27.13	$11.93	$44.95
12	$63.43	$21.14	0.00%	$0.00	-$5.94	$17.83	$45.60	$1.09	$2.44	$6.90	$0.00	$25.64	$10.46	$44.95
13	$42.28	$21.14	0.00%	$0.00	-$5.94	$11.89	$30.40	$0.73	$1.63	$6.58	$0.00	$24.14	$9.14	$44.95
14	$21.14	$21.14	0.00%	$0.00	-$5.94	$5.94	$15.20	$0.36	$0.81	$6.26	$0.00	$22.64	$7.95	$44.95
15	$0.00	$21.14	0.00%	$0.00	-$5.94	$0.00	$0.00	$0.00	$0.00	$5.94	$0.00	$21.14	$6.89	$44.95
Total	**$0.0000**	**$317.13**	**100.00%**	**$317.13**	**$0.00**	**$0.00**	**$0.00**	**$43.89**	**$98.05**	**$38.34**	**$85.00**	**$582.41**	**$390.45**	**$674.19**

Levelized Payment	$44.95

Notes:
Column (B): Beg. Bal. = LED Installation Cost; Reduced annually by Column (C)
Column (C) = Beg. Bal Column (B) / Book Life Investment (15 yrs)
Column (D) = MACRS Tax Depreciation Rate Based on 7 Years Tax Life
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Column (G) = Column (F) + Column (G) of prior period
Column (H) = Column (B) - Column (G)
Column (I) = Column (H) X Debt Ratio X Debt Cost
Column (J) = Column (H) X Equity Ratio X Equity Cost
Column (K) = Column (J) X Composite Income Tax Rate / (1 - Composite Income Tax Rate) - Column F
Column (L) = Cost of Removal Expense
Column (M) = Sum of Columns (C), (F), (I), (J), (K), (L)
Column (N) = Column (M) / [(1 + Rate of Return) ^ Column (A)]
Column (O) = Levelized charge equal to Column (N) Total on a present value basis

JCP&L LED INSTALLATION COSTS

		Direct Labor	Indirect Labor	Contractor	Total Labor	Direct Material	Indirect Material	Total Material	Direct Equipment	Indirect Equipment	Total Equipment	Total Installation Costs *	Total Installation Costs Per Unit
Cobra Head	**2400 L**	$1,661.00	$2,466.00	$398.00	$4,525.00	$1,570.00	$856.00	$2,426.00	$344.00	$41.00	$385.00	$7,336.00	$611.33
Cobra Head	**4000 L**	$1,661.00	$2,466.00	$398.00	$4,525.00	$1,543.00	$841.00	$2,384.00	$344.00	$41.00	$385.00	$7,294.00	$607.83
Cobra Head	**7000 L**	$1,661.00	$2,466.00	$398.00	$4,525.00	$1,921.00	$1,048.00	$2,969.00	$344.00	$41.00	$385.00	$7,878.00	$656.50
Cobra Head	**11500 L**	$1,661.00	$2,466.00	$398.00	$4,525.00	$2,615.00	$1,426.00	$4,041.00	$344.00	$41.00	$385.00	$8,951.00	$745.92
Cobra Head	**24000 L**	$1,661.00	$2,466.00	$398.00	$4,525.00	$4,178.00	$2,279.00	$6,457.00	$344.00	$41.00	$385.00	$11,366.00	$947.17
Acorn	**2500 L**	$1,661.00	$2,466.00	$398.00	$4,525.00	$8,849.00	$4,826.00	$13,675.00	$344.00	$41.00	$385.00	$18,585.00	$1,548.75
Acorn	**5000 L**	$1,661.00	$2,466.00	$398.00	$4,525.00	$8,442.00	$4,604.00	$13,046.00	$344.00	$41.00	$385.00	$17,955.00	$1,496.25
Colonial	**2500 L**	$1,661.00	$2,466.00	$398.00	$4,525.00	$3,597.00	$1,962.00	$5,559.00	$344.00	$41.00	$385.00	$10,468.00	$872.33
Colonial	**5000 L**	$1,661.00	$2,466.00	$398.00	$4,525.00	$4,952.00	$2,701.00	$7,653.00	$344.00	$41.00	$385.00	$12,562.00	$1,046.83

*** Total costs based on 12 units installation per day**

EXHIBIT JC-4

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony
of
Carol A. Pittavino

RE: Revenue Requirements

DIRECT TESTIMONY OF CAROL A. PITTAVINO ON BEHALF OF JERSEY CENTRAL POWER & LIGHT COMPANY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Carol A. Pittavino. My business address is 800 Cabin Hill Drive, Greensburg, PA 15601.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company ("Service Company") as a Staff Business Analyst in the Rates & Regulatory Affairs Department for Jersey Central Power & Light Company ("JCP&L" or "Company").

Q. Please describe your professional experience and educational background?

A. I am employed by FirstEnergy Service Company, and my title is Rates Consultant in the Rates & Regulatory Affairs Department for JCP&L. I report to Mark A. Mader, Director of Rates & Regulatory Affairs. My principal responsibilities are to provide accounting, financial and analytical support for JCP&L. My qualifications are set forth in detail in Appendix A to my direct testimony.

Q. Have you previously testified in proceedings before the Board of Public Utilities ("Board" or "BPU")?

A. Yes, I have. I submitted testimony (direct, supplemental and rebuttal) on behalf of JCP&L in the Company's 2012 base rate case in BPU Docket No. ER12111052 and direct testimony in the 2016 base rate case in BPU Docket No. ER16040383.

II. SUMMARY OF TESTIMONY

Q. Please summarize and describe the purpose of your direct testimony.

A. My testimony presents the revenue requirements of JCP&L, which encompass the distribution rate base and operating income and expense for the test year ending June 30, 2020, adjusted for appropriate pro-forma adjustments. My testimony supports JCP&L's Verified Petition seeking an increase in its base rates and charges of $186.9 million or a 7.8% overall average increase in JCP&L's rates.

Q. Please summarize the basis of your revenue requirement testimony.

A. I have prepared, or have had prepared under my direct supervision, a revenue requirement analysis for the test year of July 1, 2019 through June 30, 2020. The filing is based upon six months of actual data from July 1, 2019 through December 31, 2019 and six months of forecast data from January 1, 2020 through June 30, 2020 (6+6). The filing incorporates proposed adjustments to the test period that are necessary to present a level of delivery operating income representative of operating conditions that will exist when the new rates are effective. The forecast data will be updated to actuals during the course of the proceeding. In this manner, the record before the Board will contain actual accounting data for the full test year at the time that it renders a decision.

Q. Please describe and summarize the contents of the schedules to your testimony.

A. My testimony includes five schedules, with supporting pages:

Schedule CAP-1 is a statement of net utility distribution operating income for the test year ending June 30, 2020. The net operating income is presented utilizing actual and forecast data for the twelve months ending June 30, 2020 (Column 1), adjusted to remove the revenues and expenses relating to reconciling items, such as Tariff Riders and storm damage costs that are subject to deferred accounting, and transmission revenue and expenses (Column 2). The unadjusted distribution income statement (Column 3) is then adjusted to reflect normalized pro forma operating results under present rates (Column 4) and, finally, the resulting pro forma distribution income (Column 5) is adjusted to reflect additional revenues and related tax adjustments requested under the proposed rates

(Column 7). Column 6 is the change in revenue requirement necessary to allow JCP&L to earn its proposed rate of return of 7.76% on rate base (see direct testimony of JCP&L witness Joseph Dipre regarding the rate of return (Exhibit JC-9)).

The adjustments to reflect the normalized pro forma operating results under present rates are set forth on Schedule CAP-2 and are explained individually on pages 2 through 29 attached thereto. The column totals on Schedule CAP-2, page 1, correspond to the adjustment amounts on Schedule CAP-1, Column 4.

Schedule CAP-3 calculates the overall requested revenue change, including the Federal and New Jersey state income taxes associated with that change, as shown on Schedule CAP-1, page 1, Column 6. This schedule also shows the requested rate of return for the test year. Incorporating the capital structure and cost of debt as set forth in the direct testimony of Mr. Dipre (Exhibit JC-9) and the recommended return on common equity (10.15%) as set forth in the direct testimony of Dylan D'Ascendis (Exhibit JC-10), the overall rate of return requested is 7.76%.

Schedule CAP-4 computes the actual earned rate of return on rate base at the test year level of operating income, the pro forma level of operating income at present rates and the level of operating income under proposed rates.

Schedule CAP-5 shows the test year-end rate base in detail. Total plant in service reflects utility plant investment as of June 30, 2020, plus an additional six months of major capital projects and Rider RP capital projects through December 31, 2020. There is a reduction in rate base attributable to pension and other post-employment benefits ("OPEB") as supported in the direct testimony of Tracy Ashton (Exhibit JC-6). In addition, the plant in service reflects JCP&L's Reliability Plus Infrastructure Investment Program ("Reliability Plus Program") capital spend through December 31, 2020. Rate base also reflects the amortization of property-protected excess deferred income taxes ("EDITs") using the Average Rate Assumption Method ("ARAM"). The Company is proposing to include in base rates the rate base impact of the amortization of property-related unprotected EDITs, that would be recognized in the Tax Act Adjustment Rider ("TAA") as of the end of the test year. Further, the Company is proposing to include in base rates the rate base impact of the amortization of property-related unprotected EDITs through December 31, 2020. JCP&L acknowledges it will be necessary to reset Rider TAA simultaneously with the effective date of base rates resulting from this case to properly exclude these amounts from Rider TAA. The Company believes there is a benefit to recognizing the rate base impact of EDIT amortization in base rates rather than the TAA, so that the customer refunds resulting from the Tax Cuts and Jobs Act are more transparent to customers on their monthly electric bills.

The Board's long-standing practice regarding post-test year adjustments in base rate cases is based on its decision in *In re Elizabethtown Water Company*, BPU Docket No. WR8504330 (Order dated May 23, 1985), at 2 ("Elizabethtown Water"), which I will address in more detail later in my testimony. According to the Board's *Elizabethtown Water* precedent, where rate case filings include some historical and some forecast data, utilities are generally permitted to include in base rate requests known and measurable capital additions six months beyond the test year. Likewise, accumulated deferred income tax ("ADIT") and provision for accumulated depreciation are also reflected as of June 30, 2020, plus estimated accumulated depreciation and ADIT applicable to the six months of distribution major capital spend and JCP&L's Reliability Plus Program subsequent to June 30, 2020. All other rate base balances are reflected as forecasted balances as of June 30, 2020, except for Operating Reserve. The Operating Reserve balance is the December 31, 2019 actual balance and will be updated as the rate case progresses.

Rate base reflects the unamortized balance of the excess net salvage/cost of removal reserve regulatory liability balance that resulted from the elimination of net salvage/cost of removal expense from JCP&L's depreciation rates. The net salvage/cost of removal reserve regulatory liability balance was reduced by the Rider RP ("Reliability Plus") cost of removal amount of $1,137,356, which was in accordance with paragraph 34 of the Stipulation of Settlement approved in the JCP&L Reliability Plus Program proceeding in BPU Docket No. EO18070728. This amount relates to the year to date balance through December 31, 2019. In addition, the forecasted income statement cost of removal amount of $751,207 for the period of January 1, 2020 through June 30, 2020 was included for the Rider RP cost of removal. This amount represents the incremental amount, which meets the cap of $1,888,563 that was established in the JCP&L Reliability Plus Program proceeding in BPU Docket No. EO18070728. The support for the Cash Working Capital component of rate base, based on a lead-lag study, is contained in the direct testimony of James O'Toole (Exhibit JC-16).

III. SUMMARY OF RATE INCREASE AND COMPARISION WITH OTHER EDCS

Q. Based on your revenue requirements analysis, is JCP&L requesting an increase in base rates?

A. Yes. As set forth in Schedule CAP-3, JCP&L is requesting an increase in base rate revenues of $186.9 million on an annual basis or approximately a 7.8% overall average increase in JCP&L rates.

Q. How do JCP&L's rates including the proposed increase compare with those of the other New Jersey electric distribution companies ("EDCs")?

A. JCP&L has the lowest delivery and lowest total residential electric rates among the New Jersey EDCs. Due to economies of scale associated with being part of a large utility holding company system and through prudent management, JCP&L has maintained low base rates while meeting the BPU's service reliability metrics. As shown in the chart below, even after the proposed rate increase, JCP&L's delivery and total residential electric rates will still be the lowest among the four New Jersey EDCs.

Monthly Bill Comparison[1]

Class/Company	BGS	Delivery	Current Monthly[2]	Proposed Delivery	Proposed Monthly
Residential[3]					
JCP&L	$ 68.25	$ 29.45	$ 97.70	$ 37.17	$ 105.42
ACE	$ 78.42	$ 68.76	$ 147.18		
PSE&G	$ 94.85	$ 37.31	$ 132.16		
RECO	$ 57.87	$ 74.71	$ 132.58		
Commercial[4]					
JCP&L	$ 934.12	$ 403.01	$ 1,337.13	$ 506.03	$ 1,440.15
ACE	$ 903.82	$ 816.39	$ 1,720.21		
PSE&G	$ 1,192.78	$ 451.73	$ 1,644.51		
RECO	$ 811.42	$ 849.45	$ 1,660.87		

(1) For JCPL, based on rates in effect as of February 1, 2020.
For other EDCs, based on EEI Typical Bills and Average Rates Report Winter/Summer 2019, including SUT
(2) Annualized average based on 4 summer months and 8 winter months
(3) Residential amount based on 750 kWh per month.
(4) Commercial amount based on 40kW, 10000kWh per month.

IV. RELATED TESTIMONY OF OTHER JCP&L WITNESSES

Q. Please identify any testimony by other witnesses that relates to and supports your testimony.

A. Several Company witnesses have sponsored or explained test year adjustments that I have incorporated into my revenue requirements calculation:

JCP&L witness Mr. Mader (Exhibit JC-3) has presented direct testimony that includes a discussion of the Company's distribution revenues for the twelve months ending June 30, 2020. Mr. Mader's proposed revenue weather normalization has been included as an adjustment to the test year (*see* Schedule CAP-2, Adjustment No. 1), based on actual data for July 1, 2019 through December 31, 2019 and forecasted data for the period from January 1, 2020 to June 30, 2020. In addition, Mr. Mader has included the calculation of the Company's Rate Base Consolidated Tax Adjustment in his direct testimony *(See* Schedule MAM-1). Mr. Mader also testifies as to the basis for the proposed three-year amortization of deferred storm expense (*see* Schedule CAP-2, Adjustment 15).

JCP&L witness Ms. Spricigo (Exhibit JC-5) has presented direct testimony supporting certain of the test year adjustments (Adjustments 3, 5, 6, 8 and 18).

JCP&L witness Tom Donadio (Exhibit JC-13) has presented direct testimony on proposed changes to the Company's Tariff for Service, including changes related to certain fees in Part II of the Tariff.

JCP&L witness Ms. Ashton (Exhibit JC-6) has presented direct testimony that includes a discussion of pension expense and OPEB expense. Ms. Ashton's direct testimony supports the appropriate level of pension and OPEB expense to be included in the test year, which I have included in my revenue requirement calculation. (*see* Schedule CAP-2, Adjustments No. 10 and 10(a)).

JCP&L witness Dennis Pavagadhi (Exhibit JC-7) has presented direct testimony regarding vegetation management expense and storm restoration expense during the test year that supports my Adjustments No. 11, 12 and 15 (*see* Schedule CAP-2, Adjustments No. 11, 12 and 15).

V. PRO FORMA ADJUSTMENTS

Q. Can you highlight some of the pro forma adjustments the Company is including in this filing?

A. Yes. The Company has made adjustments to the test year income statement for expenses for the OPEB retiree settlement (Adjustment 9); Cost of Removal using an accrual method (Adjustment 14), Storm regulatory asset recovery using a 3-year amortization (Adjustment 15), Other corporate cost allocations (Adjustment 19), Reconciliation of the Amortization of EDITs (Adjustment 20), Production Related Asset amortization (Adjustment 22), and Service Company Operation and Maintenance ("O&M") (Adjustment 23). While it does not involve a pro forma adjustment, the Company's filing includes expenses for its short-term and long-term incentive compensation programs. The Company firmly believes that its compensation programs are market-competitive and are structured to drive benefits for both customers and shareholders.

Q. Can you expand on the post-test year adjustments that are permitted to reflect the ongoing level of costs beyond the test year?

A. Yes. According to the Board's *Elizabethtown Water* precedent, where rate case filings include some historical and some forecast data, utilities are generally permitted to include in base rate requests known and measurable adjustments three months beyond the test year for changes in capital structure, six months beyond the test year for rate base and nine months beyond the test year for revenue and expense, which is generally referred to as the "3-6-9" rule.

Q. Is JCP&L proposing adjustments beyond the test year in this filing?

A. Yes. JCP&L has included out-of-period adjustments to: 1) reflect its capital structure as of September 30, 2020 (three months beyond the end of the test year); 2) its rate base to reflect significant plant additions, and plant-related adjustments through December 31, 2020 (six months beyond the end of the test year); and 3) known and measurable adjustments to O&M expense, specifically, wage and salary increase for employees that fall within nine months after the test year.

Q. Please describe the adjustments summarized on Schedule CAP-2, page 1, and indicated individually on Schedule CAP-2, pages 2 through 27.

A. <u>Adjustment 1 – Revenue Normalization:</u> Normalizes actual test year revenue for the effects of weather. Refer to the direct testimony of Mark A. Mader (Exhibit JC-3).

<u>Adjustment 2 – Tariff Revisions</u>: Reflects the tariff adjustment for returned check charge as proposed by Thomas Donadio in his direct testimony (Exhibit JC-13).

<u>Adjustment 3</u> <u>– Interest on Customer Deposits:</u> Reflects the reclassification to operating expense of interest on customer deposits. Refer to the direct testimony of Jennifer Spricigo (Exhibit JC-5).

<u>Adjustment 4 – Annualize Payroll Wage Rate Increases at 3%:</u> Reflects the annualization of salary and wage increases using a 3% average increase. This adjustment applies to those employees who are covered by a collective bargaining agreement and will receive an actual 3% salary and wage increase during 2020 under that agreement. Also, this salary and wage adjustment includes an average 3.25% increase for those employees classified as non-bargaining for 2020. Because not all salary and wage increases are effective on January 1, 2020, the salary and wages were annualized for purposes of this adjustment to reflect a full year of the increases. This adjustment also provides for the share of the Company's 401k

retirement savings ("Savings Plan") and Federal Insurance Contributions ("FICA") tax expenses resulting from the salary and wage increase (Adjustments 4(a) and 4(b)).

This adjustment relies on the Board's long-standing practice regarding post-test year adjustments to O&M expense based on its decision in *Elizabethtown Water*. According to the Board's *Elizabethtown Water* precedent, where rate case filings include some historical and some forecast data, utilities are generally permitted to include in revenue requirement requests known and measurable adjustments to O&M expense nine months beyond the test year.

<u>Adjustment 5 – Reclassify Amortization of Net Loss on Reacquired Debt:</u> Reflects the reclassification of the amortization of the net loss on reacquired debt from interest charges to operating expense reflected on a distribution basis. Refer to the direct testimony of Jennifer Spricigo (Exhibit JC-5).

<u>Adjustment 6 – BPU and Rate Counsel Assessments:</u> Reflects a normalized level of Board and Division of Rate Counsel assessments. Refer to the direct testimony of Jennifer Spricigo (Exhibit JC-5).

<u>Adjustment 7 – Gain on Sale:</u> Reflects the return to ratepayers of 50% of the net gain on the disposition of property recorded in a liability account over a 5-year period relating to the sale of Allenhurst property in Docket EM18020193. The basis of this calculation is consistent with the methodology the Board approved in its prior orders: (1) order dated November 14, 2005, for the sale of JCP&L's Bernardsville Commercial Office (Docket EM04111473); (2) order dated December 5, 2005 for the sale of JCP&L's Belford Property (Docket EM04101073); and order dated December 21, 2005 for the sale of the Lakewood property (Docket EM04040229).

Adjustment 8 – Rate Case Expenses: Reflects the estimated expense associated with base rate proceedings. Refer to the direct testimony of Jennifer Spricigo (Exhibit JC-5).

Adjustment 9 – Retiree Benefits: Reflects an amortization over a four-year period for JCP&L's incremental OPEB costs associated with the expanded retiree eligibility criteria retroactive to January 1, 2015 as addressed in BPU Docket No. EO17080870.

Adjustment 10 – Pension and OPEB: Reflects the adjustment for pension (Adjustment No. 10) and OPEB (Adjustment No. 10(a)), as supported in the direct testimony of Tracy Ashton (Exhibit JC-6).

Adjustment 11 – Normalize Vegetation Management Expense: Reflects the adjustment to normalize the test year vegetation management expense. The adjustment is to address increases in vegetation management O&M due to the increases in vegetation management standards which occurred in 2016. The adjustment reflects the deferral of vegetation management expense in excess of 105% of the annual amount initially approved in the 2012 base rate case (see Adjustment 12 below). *See* direct testimony of Dennis Pavagadhi (Exhibit JC-7). JCP&L will continue to defer vegetation management expense consistent with the BPU's order in JCP&L's 2012 base rate case.

Adjustment 12 – Amortization of Vegetation Management Regulatory Asset: Reflects the amortization of deferred vegetation management expenses in excess of the 105% threshold established in the Company's 2012 base rate case. JCP&L witness Dennis Pavagadhi discusses vegetation management in his direct testimony (Exhibit JC-7).

Adjustment 13 – Annualize Depreciation Expense: Reflects the annualization of depreciation expense based upon the estimated net depreciable plant balance at June 30, 2020, and includes an additional depreciation expense amount attributable to the pension & OPEB delayed recognition depreciation expense, six months of additional distribution major capital projects and the JCP&L Reliability Plus Rider RP from July 1, 2020 through December 31, 2020. The depreciation rates applied in this adjustment utilize the results of the depreciation study conducted and supported by JCP&L witness John Spanos (Exhibit JC-14).

Adjustment 14 – Average Net Salvage: Reflect annual accrual expense for net salvage, which accrual rates were established based on 5-years of historical costs, which is consistent with BPU precedent, and as further described by the direct testimony of JCP&L witness John Spanos (Exhibit JC-14).

Adjustment 15 – Storm Damage Cost Amortization: Reflects the amortization of deferred storm costs of $102.4M, as of December 31, 2019 over a three-year period. This results in a pro forma adjustment of $76.86M. Please refer to the direct testimony of Mark A. Mader (Exhibit JC-3) for a discussion of the Company's storm damage cost amortization proposal.

Adjustment 16 – Service Company depreciation expense at JCP&L Rates: Reflects FirstEnergy Service Company depreciation expense applying JCP&L's depreciation rates as approved in JCP&L's 2012 base rate case (BPU Docket No. ER12111052) to allocated Service Company plant. JCP&L has conducted a new depreciation study as part of this base rate case. The calculation of depreciation in this adjustment is consistent with the methodology set forth in the direct testimony and depreciation study of JCP&L witness John Spanos (Exhibit JC-14). In addition, the allocation percentage of 14% was applied, which will be the Multi Factor-Utility & Non-Utility allocation percentage effective July 1, 2020. The use of the July 1, 2020 allocation change falls under the *Elizabethtown Water* "3-6-9" rule since July 1, 2020 falls one day after the end of the test year. Please refer to the direct testimony of Olenger Pannell (Exhibit JC-15).

Adjustment 17 – SERP/EDCP: Reflects the reduction to the income statement expense relating to the Supplemental Executive Retirement Plan and Executive Deferred Compensation Plan.

Adjustment 18 – Advertising: Removes advertising expenses that are considered promotional or institutional in nature. Refer to the direct testimony of Jennifer Spricigo (Exhibit JC-5).

Adjustment 19 – Other Corporate Cost Allocations: Is an adjustment to increase expenses to reflect certain additional corporate expenses. Refer to the direct testimony of Olenger Pannell (Exhibit JC-15).

Adjustment 20 – Reconciliation of the Amortization of EDITs: Reflects the reconciliation of the amortization of property-protected EDITs using ARAM as included in the regulatory asset in accordance with paragraph 21 approved in the Tax Cuts and Jobs Act 2017 proceeding in BPU Docket No. AX18010001.

Adjustment 21 – LED: Reflects the LED Regulatory Asset balance of $4,948 that is the remaining net book value of non-LED streetlights. The Company would include this balance along with future stranded non-LED remaining net book value amounts in the Regulatory Asset. The Regulatory Asset balance relates to the Street Lighting filing which was approved in the Company's 2016 Base Rate Case, BPU Docket Nos. ER16040383 and ET141101270. Refer to the direct testimony of Mark A. Mader (Exhibit JC-3), which addresses the proposed future recovery recovered through a Rider based on a rolling 5-year period.

Adjustment 22 – Production Related Regulatory Assets: Reflects a revised amortization of two production-related regulatory assets (Oyster Creek and TMI-1 design basic documentation studies). A portion of the subject regulatory assets has been previously approved by the Board for recovery over amortization periods that coincided with the facilities' operating license lives. Since JCP&L no longer owns these production facilities and, except for the Yards Creek pumped storage hydroelectric facility, is no longer in the generation business, the Company proposes to amortize the balance of the subject production-related regulatory assets over a three-year period to eliminate these assets from the balance sheet. The increase in amortization expense over the amount currently expensed in the test year is reflected in the amount of this adjustment.

<u>Adjustment 23-Service Company O&M</u>: Reflects an increase in Service Company O&M charged to the Company. The O&M increase of $3.7M resulted from the change in Service Company allocations charged to JCP&L due to the separation of FirstEnergy Solutions ("FES")/FENOC. Due to the fact that FES/FENOC will no longer be operating under FirstEnergy Corp. ("FirstEnergy") effective July 1, 2020, the Service Company allocation percentage will be increased to all remaining companies under FirstEnergy. Since this change occurs effective July 1, 2020 which is one day after the end of the test year, this adjustment would fall under the *Elizabethtown Water* precedent. Refer to the direct testimony of Olenger L. Pannell (Exhibit JC-15).

<u>Adjustment 24 – Investment Tax Credit Amortization:</u> Reflects the amortization of the distribution portion of the Investment Tax Credit ("ITC"). This adjustment is consistent with the Board's order in the Company's prior base rate cases.

<u>Adjustment 25 – Interest Synchronization-Tax on Long Term Debt:</u> Synchronizes the federal and state income tax savings associated with rate base, with the weighted cost of debt in the capital structure used to support rate base. This adjustment is consistent with Board orders in the Company's prior base rate cases.

Adjustment 26 – Income Taxes on Adjustments: Computes the effect on federal and state income taxes relating to the normalization adjustments 1 through 23.

Adjustment 27 – ARAM tax amortization: Computes an adjustment to test year income tax expense resulting from a comprehensive federal tax reform bill commonly known as the Tax Cuts and Jobs Act, enacted on December 22, 2017. Utilities book large reserves to account for deferred taxes resulting from the excess of accelerated tax depreciation over straight-line depreciation used for regulatory purposes. The reduction in the corporate tax rate generally creates excess reserve because previously recorded reserves assumed a 35 percent corporate tax rate, and a 21 percent rate produces less deferred taxes. This excess reserve amount or Excess Deferred Income Tax ("EDIT") was addressed in JCP&L's Tax Cuts and Jobs Act of 2017 proceeding in NJ BPU Docket No. AX18010001 and ER18030226. Per Paragraph 19 of the Order, the parties agreed that base rates would be adjusted to reflect the amortization of the property-related protected EDIT asset using the Average Rate Assumption Method ("ARAM"). Therefore, this adjustment serves to adjust JCP&L's base rate tax amount for the impact of the EDIT amortization net of tax.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

DIRECT TESTIMONY OF CAROL A. PITTAVINO ON BEHALF OF JERSEY CENTRAL POWER & LIGHT COMPANY

EDUCATIONAL AND PROFESSIONAL BACKGROUND

My name is Carol Pittavino and my business address is 800 Cabin Hill Drive, Greensburg, Pennsylvania, I am currently employed by FirstEnergy Service Company as a Rates Consultant of Rates and Regulatory Affairs Department – New Jersey, reporting to the Director of Rates and Regulatory Affairs. I am responsible for providing accounting, financial and analytical support for rate activities.

I graduated from Seton Hill University (then College) in May 2000 with a Bachelor of Science degree with a major in accounting. I earned my Pennsylvania Certified Public Accountant license in September 2003.

In August 2012, I was employed by JCP&L as a rates analyst. From November 2017 to January 2019, I held an Analyst position in the FirstEnergy Transmission Business Services area, while continuing to support Rates and Regulatory Affairs. In January 2019, I returned to JCP&L Rates and Regulatory Affairs. From October 2003 to September 2010 I was employed by Allegheny Energy, Inc. as a Senior Accountant in the Regulatory Accounting department. One of my primary responsibilities was FERC Form 1 preparation and analysis. I also performed General Accounting responsibilities and performed forecasting preparation for the regulated subsidiary entities owned by Allegheny Energy, Inc. In addition, I assisted the Rate Department with a Base Case filing as well as prepared the revenue requirement calculation on transmission line construction projects.

I was employed at United Health Group from October 2010 to July 2012 as a Senior Accountant. I was responsible for the oversight and accounting functions of two Medicaid Managed Care Organizations.

From May 2001 through September 2003 I was employed at S.R. Snodgrass as a Senior Accountant. S.R. Snodgrass is a regional public accounting firm which performs external and internal audit services for their clients. I functioned as an external auditor assisting in the drafting and inspection of the financial records of clients, which ultimately resulted in issuing an opinion on the authenticity of their financial records.

From June 1985 through April 2001, I was employed for the First National Bank of Herminie. I held various positions when I was employed by the bank. I progressed through all aspects of branch operations which resulted in Branch Manager. I transferred into the finance department as an Accountant and functioned in this capacity until the bank was acquired by The First National Bank of Pennsylvania in April 2001.

JERSEY CENTRAL POWER & LIGHT COMPANY
Pro Forma Statements of Net Utility Operating Income for the Twelve Months Ended 6/30/20
Normalized and Adjusted to Reflect the Effect of Known Major Changes and Proposed Rates

Line No.		Unadjusted Total Company (a) (1)	Non-Distribution Adjustments (b) (2)	Unadjusted Distribution (3)	Normalization Adjustments (4)	Pro Forma Present Rates (5)	Additional Revenue to Achieve Return (6)	Requested Pro Forma Proposed Rates (7)
1	Electric Retail Sales	$ 1,657,712,583	$ (1,105,095,727)	$ 552,616,855	$ (9,748,087)	$ 542,868,768	$ 186,945,938	$ 729,814,706
2	Sales for Resale	30,861,432	(30,861,432)	-				
3	Total Electric Sales	$ 1,688,574,015	$ (1,135,957,159)	$ 552,616,855	$ (9,748,087)	$ 542,868,768	$ 186,945,938	$ 729,814,706
4	Other Operating Revenue	108,694,583	(93,151,484)	15,543,099	(268,082)	15,275,018		15,275,018
5	Total Revenue	$ 1,797,268,598	$ (1,229,108,643)	$ 568,159,954	$ (10,016,169)	$ 558,143,786	$ 186,945,938	$ 745,089,724
			-					
6	O&M - Production	$ 905,397,899	$ (905,397,899)	$ -	$ -	$ -		$ -
7	O&M - Transmission	31,923,079	(31,923,079)	-	-	-		-
8	O&M - Distribution	162,675,860	(68,859,000)	93,816,859	12,218,682	106,035,541		106,035,541
9	O&M - Customer Accounts	37,497,368	(7,214,037)	30,283,331	-	30,283,331		30,283,331
10	O&M - Customer Service	117,982,985	(107,014,623)	10,968,363	-	10,968,363		10,968,363
11	O&M - Sales Expense	56,383		56,383		56,383		56,383
12	O&M - A&G	126,711,917	(31,090,453)	95,621,464	(15,592,658)	80,028,806		80,028,806
13	Subtotal Operation & Maintenance	$ 1,382,245,492	$ (1,151,499,092)	$ 230,746,400	$ (3,373,977)	$ 227,372,423	$ -	$ 227,372,423
			-					
14	Depreciation & Amortization	$ 177,475,443	$ (48,792,377)	$ 128,683,066	$ 25,777,280	$ 154,460,346		$ 154,460,346
15	Regulatory Debits	62,550,503	(36,874,617)	25,675,886	82,287,862	107,963,748		107,963,748
16	Regulatory Credits	(97,478,122)	84,932,699	(12,545,423)	(101,996)	(12,647,419)		(12,647,419)
17	Taxes Other Than Income	11,399,506	(1,842,178)	9,557,328	345,139	9,902,467		9,902,467
18	Accretion Expense	9,380,189		9,380,189		9,380,189		9,380,189
19	Total Operating Expenses	$ 1,545,573,011	$ (1,154,075,565)	$ 391,497,446	$ 104,934,308	$ 496,431,754	$ -	$ 496,431,754
20	Operating Income Before Income Taxes	$ 251,695,587		$ 176,662,508	$ (114,950,477)	$ 61,712,031	$ 186,945,938	$ 248,657,969
21	Income Taxes	$ 31,767,925		$ 49,659,831	$ (55,228,851)	$ (5,569,020)	$ 52,550,503	$ 46,981,483
22	Net Utility Operating Income	$ 219,927,662		$ 127,002,677	$ (59,721,626)	$ 67,281,051	$ 134,395,435	$ 201,676,486

(a) Includes July to December 2019 actuals and forecasted January to June 2020 income statement.
(b) Consists of revenues and expenses related to transmission operations and reconciling revenue and expense items.

JERSEY CENTRAL POWER & LIGHT COMPANY
Summary of Test Year Normalization/Annualization Adjustments

Adjmt. No.		Revenue (1)	O&M (2)	Depreciation (3)	Amortization (4)	Taxes (5)	Total (6)
1	Revenue Normalization Adjustment	(10,067,197)					
2	Tariff Fee Adjustments	51,028	-		-		
3	Interest on Customer Deposits		1,104,116				
4	Annualize Salary and Wage Rate Increases at 3%		4,511,619				
4(a)	Savings Plan - Company Contribution for S&W Increase		135,349				
4(b)	FICA Tax on annualized S&W Increases					345,139	
5	Reclass Amortization of Net Loss on Reacquired Debt		638,187				
6	BPU & Rate Counsel Assessments		(425,441)				
7	Return Net Gain on Sale of Property				(101,996)		
8	Rate Case Expenses		156,039				
9	OPEB Settlement				1,187,500		
10	Pension		(25,638,726)				
10(a)	OPEB		7,176,427				
11	Normalize Vegetation Management Expense		5,808,721				
12	Amortization of Vegetation Management Regulatory Asset				2,894,215		
13	Annualize Depreciation Expense			17,988,446			
14	Average Net Salvage			7,788,834			
15	Storm Damage Cost Amortization				76,863,146		
16	Service Company Depreciation Expense at JCP&L Rates		1,710,308				
17	SERP/EDCP		(1,181,606)				
18	Advertising		(924,095)				
19	Other Corporate Cost Allocations		147,821				
20	ARAM Amortization				131,215		
21	LED				-	-	
22	Production Related Regulatory Asset Amortization				1,211,786		
23	Service Company O&M		3,407,305				
24	Investment Tax Credit Amortization					(97,625)	
25	Interest Synchronization - Tax on Long Term Debt					(17,527,360)	
26	Income Taxes on Adjustments					(32,312,579)	
27	Tax Reform Amortization					(5,291,287)	
	Total Adjustments	(10,016,169)	(3,373,977)	25,777,280	82,185,866	(54,883,712)	59,721,626

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 1

Adjustment to retail distribution revenue for weather normalization.

Electric sales (distribution) revenue 12ME June 2020	$	552,616,855	(a)
Weather-normalized distribution revenue		542,549,658	
Adjustment to total revenue	$	(10,067,197)	
Electric sales (distribution) revenue 12ME June 2020	$	552,616,855	
Weather normalized distribution revenue (based on billing determinants)		542,868,768	
Adjustment to retail revenue	$	(9,748,087)	
Adjustment to retail revenue	$	(9,748,087)	
Misc adjustments to other operating revenue		(319,110)	
Adjustment to total revenue	$	(10,067,197)	

(a) Reference schedule CAP-1, column 3, line 1.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 2

Adjustment to other operating income to reflect proposed fee changes in Tariff Part III - Service Classifications.

	Test Year Other Oper Rev (1)	Current Fee (2)	No. of Occurrences (1)/(2)=(3)	Proposed Fee (4)	Estimated Annual Revenue (3)x(4)=(5)	Adjmt to Other Revenue (5)-(1)
Return Check Charge	$ 204,137	$ 12.00	17,011	$ 15.00	$ 255,165	$ 51,028
Total Adjustment to Other Operating Revenue						$ 51,028

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 3

Adjustment to reclassify and annualize interest on customer deposits.

Forecasted customer deposits balance at 06/30/2020	$ 47,386,955	
Interest rate 2020	2.33%	(a)
Annualized interest on customer deposits	$ 1,104,116	

(a) Based upon the average yield on new six month Treasury Bills for the 12-month period ending September 30, 2019.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 4, 4(a) and 4(b)

Adjustment (4) reflects annualized salary and wage ("S&W") rate increases (WRI) effective November 1 and May 1 for bargaining and non-bargaining employees, respectively. Additional adjustments for the impact of the S&W increase was applied to the savings plan 4(a) and FICA tax 4(b).

	Total straight-time labor cost		
	Bargaining	Non-Bargaining	Total
Annualized S&W cost with WRI	$ 60,639,348	$ 25,413,821	$ 86,053,169
12 months ending June 2020 test year amount	$ 57,444,194	$ 24,097,357	$ 81,541,550
Adjustment No. 4	$ 3,195,154	$ 1,316,464	$ 4,511,619

Total savings plan - Company contribution for annualized Salary & Wage Increase *			
	Bargaining	3%	$ 95,855
	Non-Bargaining	3%	$ 39,494
Adjustment No. 4(a)	TOTAL		$ 135,349
Total FICA tax on annualized S&W Increase **			
	Bargaining	7.65%	$ 244,429
	Non-Bargaining	7.65%	$ 100,710
Adjustment No. 4(b)	TOTAL		$ 345,139

* Company contributes 50 cents per dollar up to 6%.
** Federal Insurance Contribution Act "FICA"-Social Security rate of 6.2% plus 1.45% Medicare.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 5

Adjustment to reclassify the amortization of net loss on reacquired debt from interest charges to operation expense.

Amortization of loss on reacquired debt at 6/30/2020	$	877,378
Amortization of gain on reacquired debt at 6/30/2020		(19,716)
Amortization of net loss on reacquired debt	$	857,662
Distribution plant allocation		74.41%
Distribution net loss on reacquired debt	$	638,187

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 6

Adjustment to NJBPU and Rate Counsel Assessments based on weather-normalized test year revenues.

	NJBPU	RPA	Total
Gross revenues from intrastate sales			$1,774,993,134 (a)
Assessment rate	0.2311%	0.0553%	
Total assessment	$ 4,102,009	$ 981,571	$ 5,083,580
Test year accrued amount	4,483,645	1,025,376	5,509,021
Adjustment to assessment expense	$ (381,636)	$ (43,805)	$ (425,441)

(a) Amount will be adjusted to reflect the revenue requirement approved by the BPU.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 7

Gain on the Sale of Utility Property to be shared 50% with shareholders in accordance with prior BPU Orders

		at 6/30/2020
Gain on Sale of Assets	$	(1,019,956)
50% Sharing	$	(509,978)
Amortization in years		5
Annual amortization	$	(101,996)
Expense in test year		-
Adjustment to test year	$	(101,996)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 8

Adjustment to reflect amortization of expense associated with various rate and regulatory proceedings

Estimated rate case expense for 2020 case:		
Legal fees and expenses	$	1,000,000
Consultant fees and expenses	$	154,310
Court reporter fees	$	3,000
Duplication	$	24,000
Public notices	$	65,000
Postage/messenger service	$	2,000
Total	$	1,248,310
50/50 Sharing	$	624,155
Amortization period in years		4
2020 base rate case annual amortization expense	$	156,039
Total annual base rate case amortization	$	156,039

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 9

Adjustment to reflect amortization of expense associated with the OPEB retiree settlement.

OPEB liability concerning settlement	$	4,750,000
Total OPEB Liability	$	4,750,000
Amortization 4 years		4
Total Annual OPEB Retiree Amortization	$	1,187,500

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 10

Adjustment to Test Year pension expense to reflect actuarial gains/losses under the pre-2011 accounting methodology.

Line No.	Description	12 ME June 30 2020 Amount
1	Pension expense per books	$ 38,113,428
2	Remove test year pension M-t-M expense for actuarial gains/losses	$ (68,048,327)
3	Add test year pension expense for actuarial gains/losses using pre-2011 acctg methodology	$ 39,991,065
4	Adjustment to test year pension expense (Line 2 + Line 3)	$ (28,057,262)
5	Distribution allocation percentage based on 2018 distribution S&W	91.38%
6	Adjustment to test year pension expense to reflect actuarial gains/losses under the pre-2011 acctg methodology	$ (25,638,726)
7	Total requested distribution pension expense	$ 9,189,325

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 10(a)

Adjustment to Test Year OPEB expense to reflect actuarial gains/losses under the pre-2011 accounting methodology.

Line No.	Description	12 ME June 30 2020 Amount
1	OPEB expense per books	$ 2,869,574
2	Remove test year OPEB M-t-M expense for actuarial gains/losses	$ (1,824,284)
3	Add test year OPEB expense for actuarial gains/losses using pre-2011 acctg methodology	$ 9,677,673
4	Adjustment to test year OPEB expense (Line 2 + Line 3)	$ 7,853,389
5	Distribution allocation percentage based on 2018 distribution S&W	91.38%
6	Adjustment to test year OPEB expense to reflect actuarial gains/losses under the pre-2011 acctg methodology	$ 7,176,427
7	Total requested distribution OPEB expense	$ 9,798,644

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 11

Adjustment to address both the ongoing increased expense associated with new BPU vegetation management standards, and the test year level of spending above the amount the BPU approved in the Company's last base rate case.

	Vegetation Management Expense	
Total test year distribution vegetation management O&M expense	$ 17,758,239	
Test year distribution vegetation management O&M expense less deferred amount	11,949,519	*
Adjustment to test year vegetation management O&M expense	$ 5,808,721	

* Amount approved in 2016 Base Rate case per BPU Docket No. ER16040383.
($11,380,494 X 1.05 = $11,949,519)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 12

Adjustment to reflect amortization of deferred distribution vegetation management expense per authorized approval in BPU Docket No. ER12111052.

Actual distribution vegetation management regulatory asset at 12/31/19	$ 9,660,907
Forecasted distribution vegetation management regulatory asset at 6/30/20	$ 1,915,953
Total estimated recoverable forestry regulatory asset	$ 11,576,860
Amortization 4 years	4
Total annual vegetation management amortization	$ 2,894,215

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 13

Adjustment to annualize depreciation expense net of cost of removal.

	Depreciation Expense
Distribution Plant:	
Annualized depreciation expense	$ 111,753,973
General plant allocated to distribution:	
Annualized GP depreciation expense	7,802,381
General Plant unrecovered reserve amortization	2,637,161
Total annualized depreciation expense	$ 122,193,515
Total annualized depreciation expense in test year	104,626,245
Adjustment to depreciation expense (403)	$ 17,567,269
Intangible plant allocated to distribution:	
Annualized IP amortization expense	$ 9,359,869
Test year IP amortization expense	8,815,151
Adjustment to test year amortization expense (404)	$ 544,718
Delayed Recognition Pension & OPEB	$ (1,545,534)
Add depreciation associated with post TY CAPEX	663,309
Add Rider RP Depreciation	758,683
Total	$ (123,542)
Total Depreciation and Amortization Adjustment	$ 17,988,446

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 14

Adjustment to net cost of removal allowance, based on accrual method, not included in depreciation rate.

Net average cost of removal/salvage (Distribution)	$	23,030,504
Net cost of removal/salvage accrual test year		15,241,670
Adjustment to the allowance for net COR/Salvage	$	7,788,834

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 15

Adjust amortization of deferred storm damage costs.

	Regulatory Asset Balance @ 12/31/2019
Other Storms	$ 289,620,885
2011 Hurricane Irene (a)	17,669,190
Total December 31, 2019 Balance	$ 307,290,074
3-Year Amortization	3
Annual Amortization	$ 102,430,025
Less amortization included in test year	25,566,879
Adjustment	$ 76,863,146

(a) Storm costs include deferred storm damages relating to storms, which were granted a separate recovery in BPU Docket No. ER12111052.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 16

Adjustment to recalculate First Energy Service Company depreciation using JCP&L's depreciation rates.

FIRSTENERGY SERVICE COMPANY

12 Months Ended June 30, 2020

	DESCRIPTION	BALANCE AT July 1, 2019	Depreciation on Beginning Balance	Depreciation on Plant Additions	Based on JCPL rates Total Depreciation	FECO Depreciation UI Planner FERC 403 Depreciation Exp	Difference
SERVICE COMPANY PROPERTY							
Account							
301	ORGANIZATION	49,344	0	0	0	0	0
303	MISCELLANEOUS INTANGIBLE PLANT	417,629,746	36,409,849	0	36,409,849	36,407,057	2,792
304	LAND & LAND RIGHTS	230,947					0
305	STRUCTURES AND IMPROVEMENTS	65,374,594	908,141	(121,503)	786,638	2,693,769	(1,907,132)
306	LEASEHOLD IMPROVEMENTS (1)	0	0	0	0		
307	EQUIPMENT (2)	138,805,687	6,936,688	157,524	7,094,212	8,185,751	(1,091,539)
308	OFFICE FURNITURE AND EQUIPMENT	167,978,724	30,835,299	2,347,412	33,182,711	17,437,196	15,745,515
309	AUTOMOBILES, OTHER VEHICLES AND RELATED GARAGE EQUIPMENT	2,128,404	90,040	22,439	112,479	275,409	(162,931)
310	AIRCRAFT AND AIRPORT EQUIPMENT	0	0	0	0	0	0
311	OTHER SERVICE COMPANY PROPERTY	0	0	0	0	0	0
	SUB - TOTAL	792,197,447	75,180,016	2,405,872	77,585,889	64,999,182	12,586,706
	Year 2020 allocation factor from SC00 to JCP&L for Depr Expense				14.87%	14.87%	
	2020 annual depreciation expense allocated to JCP&L				**$ 11,537,022**	**$ 9,665,378**	1,871,643
				Distribution allocation based upon Salaries and Wages			91.38%
				Distribution Service Company Depreciation			**$ 1,710,308**

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 17

Adjustment to remove SERP "Supplemental Executive Retirement Plan" and EDCP "Executive Deferred Compensation Plan" expense.

SERP & EDCP:		
JCP&L	$	(242,347)
Service Company		(1,050,698)
Total	$	(1,293,045)
Salary and wage distribution allocator		91.38%
Adjustment to remove SERP and EDCP	$	(1,181,606)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 18

Adjustment to remove advertising expenses relating to promotional, institutional or civic memberships.

		Amount
Informational or instructional advertising	$	72,490
12 Months-ending June 2020 TY Expense	$	996,585
Adjustment to remove advertising expense	$	(924,095)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 19

Other Corporate Cost Allocations

12 Months ended 6/30/2020	FERC Accounts	Amount	Retention	Multifactor allocation % to JC01 (MA1)	Test year amount allocated to JC01	S&W Alloc	JCPL Distribution
Audit fees	923.0	1,206,798	5%	14.11%	161,765	91.38%	147,821
		$ 1,206,798			$ 161,765		147,821

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 20

Adjustment to reflect amortization of expense associated with ARAM underrecovery.

ARAM underrecovery concerning TCJA:	
ARAM underrecovery	$ 524,862
Amortization period in years	4
Total Annual ARAM Amortization	$ 131,215

NOTE: ARAM underrecovery per BPU order.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 21

Adjustment relating to LED regulatory asset.

ARAM underrecovery concerning TCJA:	
LED Regulatory Asset	$ 4,948
Amortization period in years	$ -
Total LED amortization	$ -

Note:
Company not requesting recovery at this time.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 22

Adjustment to accelerate the amortization of production-related regulatory assets.

			6/30/2020
Balance of deferred Oyster Creek Design Basis Documentation costs			$ 2,701,657
Balance of deferred TMI-1 Design Basis Documentation costs			1,260,726
			$ 3,962,383
Amortization over 3 years			$ 1,320,794
Amortization in test year 2020	Oyster Creek DBD	$ 83,004	
	TMI-1 DBD	$ 26,004	109,008
Adjustment to amortization expense			$ 1,211,786

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 23

Adjustment to operations & maintenance expense due to corporate allocation change.

	6/30/2020
O&M	$ 3,728,721
Distribution S&W allocator	91.38%
Adjustment to expense	$ 3,407,305

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 24

Adjustment to include investment tax credit amortization.

Investment Tax Credit:		
FERC Account 411.40	$	(131,199)
Distribution plant allocator		74.41%
Adjustment for distribution investment tax credit	$	(97,625)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 25

Income taxes associated with synchronized interest on outstanding debt

Synchronized Cost of Debt at end of test year (a)		$ 62,352,756
State Corporate Business Tax	9.00%	(5,611,748)
Federal Income Tax	21.00%	(11,915,612)
Tax Adjustment		$ (17,527,360)

(a) Rate Base at end of test year		$ 2,598,923,793
Weighted cost of debt		
Cost of Debt	5.083%	
Long Term Debt capitalization ratio	47.20%	2.40%
Total synchronized cost of debt		$ 62,352,756

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 26

Effect of Applicable Adjustments on Income Taxes.

Adjustment No.			Effect on Taxable Income
1	Revenue Normalization Adjustment		$ (10,067,197)
2	Tariff Fee Adjustments		$ 51,028
3	Interest on Customer Deposits		$ (1,104,116)
4	Annualize Payroll Wage Rate Increases		$ (4,511,619)
4 (a)	Savings Plan match on Payroll Wage Increase		$ (135,349)
4 (b)	FICA tax on Payroll Wage Increase		$ (345,139)
5	Reclass Amortization of Net Loss on Reacquired Debt		$ (638,187)
6	BPU & Ratepayer Advocate Assessments		$ 425,441
7	Return Net Gain on Sale of Property		$ 101,996
8	Rate Case Expenses		$ (156,039)
9	OPEB Settlement		$ (1,187,500)
10(a)	Pension Smoothing		$ 25,638,726
10(b)	OPEB Smoothing		$ (7,176,427)
11	Normalize Forestry Maintenance Expense		$ (5,808,721)
12	Amortization of Forestry Regulatory Asset		$ (2,894,215)
13	Annualize Depreciation Expense		$ (17,988,446)
14	Average Net Salvage		$ (7,788,834)
15	Storm Damage Cost Amortization		$ (76,863,146)
16	Service Company depreciation expense at JCP&L Rates		$ (1,710,308)
17	SERP/EDCP		$ 1,181,606
18	Remove Advertising (promotional, institutional and civic)		$ 924,095
19	Other Corporate Cost Allocations		$ (147,821)
20	ARAM		$ (131,215)
21	LED		$ -
22	Production Related Regulatory Asset Amortization		$ (1,211,786)
23	Service Company O&M		$ (3,407,305)
	Taxable income for State income taxes		$ (114,950,477)
	New Jersey Corporate Business Tax at	9.00%	$ (10,345,543)
	Taxable income for Federal income taxes		$ (104,604,934)
	Federal income tax at	21.00%	$ (21,967,036)
	Total income taxes		$ (32,312,579)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 27

Base Rate ARAM Amortization

		Amount
Grossed-Up For Tax	Protected Property	(7,965,052)
Net of Tax	Protected Property	(5,726,076)
Grossed-Up For Tax	NOL	604,798
Net of Tax	NOL	434,789
ARAM Net of Tax Amount		(5,291,287)

JERSEY CENTRAL POWER & LIGHT COMPANY
Explanation of Adjustments Under Proposed Rates

			Additional Revenues To Achieve Return
Rate Base		$ 2,598,923,793	
Rate of Return (A)		7.76%	
Return Required		201,676,486	
Normalized Income		67,281,051	
Income Deficiency		134,395,435	
Tax Gross-up Factor		1.391014049	
Revenue Deficiency		$ 186,945,938	
Proposed Increase in Revenues			$ 186,945,938
State Corporate Business Tax	9.00%		16,825,134
Federal Income Tax	21.00%		35,725,369
Total Tax	28.11%		52,550,503
Effect on Operating Income			$ 134,395,435

(A) Required Rate of Return	Capitalization Ratio	Embedded Cost	Rate of Return
Long Term Debt	47.20%	5.083%	2.40%
Common Equity	52.80%	10.15%	5.36%
Total Rate of Return	100.00%		7.76%

JERSEY CENTRAL POWER & LIGHT COMPANY
Actual and Pro Forma Rates of Return for Test Year
Adjusted to Reflect the annualized Effect of Proposed Rates
and of Known Major Changes

Present Rates	
Actual plus forecast (6+6)	
Operating Income	$ 127,002,677
Net Investment in Rate Base	$ 2,598,923,793
Rate of return	4.89%
Pro Forma	
Operating Income	$ 67,281,051
Net Investment in Rate Base	$ 2,598,923,793
Rate of return	2.59%
Proposed Rates	
Pro Forma	
Operating Income	$ 201,676,486
Net Investment in Rate Base	$ 2,598,923,793
Rate of return	7.76%

JERSEY CENTRAL POWER & LIGHT COMPANY
Distribution Rate Base at End of Test Year

Line No.		Balance at 6/30/2020 (a)	Balance at 6/30/2020 (b)	Balance 12/31/2020 '(c)	Balance 12/31/2020 (d)	Total Rate Base
		(1)	(2)	(3)	(4)	(5) (Sum 1 to 4)
1	Total Electric Utility Plant in Service	$ 5,504,036,320	$ (68,892,010)	$ 30,013,986	$ 31,402,232	$ 5,496,560,528
	Deductions:					
2	Accumulated Provision for Depreciation	1,795,765,630	(12,716,844)	663,309	758,683	1,784,470,778
3	Accumulated Deferred Income Tax	1,117,838,777	(15,964,351)	129,929	325,301	1,102,329,656
4	Customer Advances for Construction (Net of Deferred Tax)	34,598,405				34,598,405
5	Customer Deposits	47,386,955				47,386,955
6	Customer Refunds	4,033,419				4,033,419
7	Excess Cost of Removal	87,758,072				87,758,072
8	Operating Reserves	10,699,965				10,699,965
9	Consolidated Tax Adjustment	20,787,390				20,787,390
		-				-
10	Total Deductions	$ 3,118,868,613	$ (28,681,195)	$ 793,238	$ 1,083,984	$ 3,092,064,640
	Additions:					
11	Unamortized Net Loss on Reacquired Debt	2,178,358				2,178,358
12	Net Operating Loss	22,826,438				22,826,438
13	Property Related Unprotected Amortization	32,052,681				32,052,681
	Total Additions	$ 57,057,477	$ -	$ -	$ -	$ 57,057,477
	Working Capital:					
14	Materials & Supplies Inventory	22,844,588				22,844,588
15	Cash Working Capital	114,525,841				114,525,841
16	Total Working Capital	$ 137,370,429	$ -	$ -	$ -	$ 137,370,429
17	Total Net Rate Base Investment	$ 2,579,595,612	$ (40,210,815)	$ 29,220,748	$ 30,318,248	$ 2,598,923,793

(a) Inclusive of Rider RP forecast in service through 06/30/2020

Capital Additions	65,607,683
Accumulated Provision for Depreciation	(614,298)
Accumulated Deferred Income Tax	(208,173)
Rider RP Deferred Cost of Removal	1,888,563
Net Rate Base	$ 66,673,775
Inclusive of Property Related Unprotected Amortization from 07/1/2019 through 12/31/2020	$ 32,052,681

(b) Pension & OPEB Delayed Recognition
(c) Major Reliability Projects forecast to be in service through 12/31/2020 (six months beyond the test year)
(d) Rider RP Projects forecast to be in service through 12/31/2020 (six months beyond the test year)

EXHIBIT JC-5

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony
of
Jennifer Spricigo

RE: O&M Adjustments

I. <u>INTRODUCTION AND SUMMARY OF TESTIMONY</u>

Q. Please state your name and business address.

A. My name is Jennifer Spricigo. My business address is 300 Madison Avenue, Morristown, NJ 07960.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company ("Service Company") as a Business Analyst in the Rates & Regulatory Affairs Department for Jersey Central Power & Light Company ("JCP&L" or "Company").

Q. Please describe your professional experience and educational background?

A. I am employed by FirstEnergy Service Company, and my title is Rates Analyst in the Rates & Regulatory Affairs Department for JCP&L. I report to Mark A. Mader, Director of Rates & Regulatory Affairs. My principal responsibilities are to provide accounting, financial and analytical support for Jersey Central Power & Light Company ("JCP&L"). My qualifications are set forth in detail in Appendix A to my direct testimony.

Q. Have you previously testified in proceedings before the Board of Public Utilities ("Board" or "BPU")?

A. No; I have not previously testified in a proceeding before the Board.

Q. Please describe the purpose of your direct testimony.

A. I am sponsoring certain normalization/annualization operations and maintenance ("O&M") expense adjustments to the test year ending June 30, 2020.

II. O&M RATE ADJUSTMENTS

Q. Please describe and summarize the contents of the schedules to your testimony.

A. My testimony includes five schedules, with supporting pages, one for each of the five adjustments to the test year O&M expense that I am supporting:

Adjustment 3 – Interest on Customer Deposits: Reflects the reclassification to operating expense of interest on customer deposits at the rate of 2.33% based upon the estimated customer deposit balance at June 30, 2020, which balance is a deduction from rate base. The calendar year 2020 interest rate is equal to the average rate on six-month Treasury bills for the 12-month period ending September 30, 2019 as approved by the Board on October 7, 2019. *See* Schedule JS-1.

Adjustment 5 – Reclassify Amortization of Net Loss on Reacquired Debt: Reflects the reclassification of the amortization of the net loss on reacquired debt from interest charges to operating expense reflected on a distribution basis. Under Generally Accepted Accounting Principles ("GAAP"), if debt is terminated or significantly modified, the Company must recognize, with a charge to income or expense, any gain or loss associated with the termination and any deferred issuance costs, in the period that debt is terminated or significantly modified. Deferred net unamortized gain/loss on reacquired debt occurs when there is a redemption or reacquisition of long-term debt and there exists remaining unamortized original debt expense or discounts and/or financing costs relating to the original debt issuance. The balance of the net gains/losses on reacquired debt is amortized in interest expense over the remaining original life of the debt. These costs are treated as regulatory assets for financial reporting purposes because they qualify as such under GAAP due to the approval of the Board to recover these deferred gains and losses. It is the practice of JCP&L and the Board to include this expense in the test year and this adjustment has been reflected in prior base rate proceedings in the same manner. *See* Schedule JS-2.

<u>Adjustment 6 – BPU and Rate Counsel Assessments:</u> Reflects a normalized level of Board and Division of Rate Counsel assessments. This adjustment is based upon the normalized test year revenues and 2020 actual assessment rates; however, the amount will be adjusted to reflect the revenue requirement approved by the BPU. *See* Schedule JS-3.

<u>Adjustment 8</u> – <u>Rate Case Expenses:</u> Reflects the estimated expense associated with base rate proceedings. This adjustment includes an estimated rate case amortization amount for this proceeding that will be updated throughout and at the conclusion of this proceeding. *See* Schedule JS-4.

<u>Adjustment 18 – Advertising:</u> Removes advertising expenses that are considered promotional or institutional in nature. *See* Schedule JS-5.

Q. How are your five adjustments incorporated into JCP&L's overall revenue requirement calculation in its base rate case filing?

I have provided my adjustments to JCP&L witness Carol. A. Pittavino, who is the Company's overall revenue requirements witness in this rate case. Please refer to Ms. Pittavino's testimony, Exhibit JC-4.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

EDUCATIONAL AND PROFESSIONAL BACKGROUND

My name is Jennifer Spricigo and my business address is 300 Madison Avenue, Morristown, New Jersey. I am currently employed by FirstEnergy Service Company as a Rates Analyst of the Rates and Regulatory Affairs Department – New Jersey, reporting to the Director of Rates and Regulatory Affairs. I am responsible for providing accounting, financial and analytical support for rate activities.

I graduated from Seton Hall University in May 1992 with a Bachelor of Science degree with a major in accounting. I earned my Master of Business Administration from California Coast University in September 2008.

In August 1992, I was employed by JCP&L as an Accountant in the General Accounting Department. I worked in the Accounting Department for many years performing General Accounting responsibilities including FERC Form 1 preparation, forecasting and monthly closings. I also worked in the Tax Department for FirstEnergy Co. as a Senior Tax Analyst. My responsibilities included Federal and State Tax return preparation, implementation of Tax Software and FERC Form 1 preparation. In June 2018, I transferred into the JCP&L Rates Department. I am responsible for providing accounting, financial and analytical support for rates activities.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 3

Adjustment to reclassify and annualize interest on customer deposits.

Forecasted customer deposits balance at 06/30/2020	$ 47,386,955	
Interest rate 2020	2.33%	(a)
Annualized interest on customer deposits	$ 1,104,116	

(a) Based upon the average yield on new six month Treasury Bills for the 12-month period ending September 30, 2019.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 5

Adjustment to reclassify the amortization of net loss on reacquired debt from interest charges to operation expense.

Amortization of loss on reacquired debt at 6/30/2020	$ 877,378
Amortization of gain on reacquired debt at 6/30/2020	(19,716)
Amortization of net loss on reacquired debt	$ 857,662
Distribution plant allocation	74.41%
Distribution net loss on reacquired debt	$ 638,187

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 6

Adjustment to NJBPU and Rate Counsel Assessments based on weather-normalized test year revenues.

	NJBPU	RPA	Total	
Gross revenues from intrastate sales			$1,774,993,134	(a)
Assessment rate	0.2311%	0.0553%		
Total assessment	$ 4,102,009	$ 981,571	$ 5,083,580	
Test year accrued amount	4,483,645	1,025,376	5,509,021	
Adjustment to assessment expense	$ (381,636)	$ (43,805)	$ (425,441)	

(a) Amount will be adjusted to reflect the revenue requirement approved by the BPU.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 8

Adjustment to reflect amortization of expense associated with various rate and regulatory proceedings

Estimated rate case expense for 2020 case:		
Legal fees and expenses	$	1,000,000
Consultant fees and expenses	$	154,310
Court reporter fees	$	3,000
Duplication	$	24,000
Public notices	$	65,000
Postage/messenger service	$	2,000
Total	$	1,248,310
50/50 Sharing	$	624,155
Amortization period in years		4
2020 base rate case annual amortization expense	$	156,039
Total annual base rate case amortization	$	156,039

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 18

Adjustment to remove advertising expenses relating to promotional, institutional or civic memberships.

	Amount
Informational or instructional advertising	$ 72,490
12 Months-ending June 2020 TY Expense	$ 996,585
Adjustment to remove advertising expense	$ (924,095)

EXHIBIT JC-6

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony
of
Tracy M. Ashton

Re: Pension and OPEB Expense

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Tracy M. Ashton, and my business address is 76 South Main Street, Akron, Ohio 44308.

Q. By whom are you employed and in what capacity?

A. I am Assistant Controller, Corporate of FirstEnergy Corp. ("FirstEnergy") and a number of its subsidiaries.

Q. What are your educational and professional qualifications?

A. My qualifications are set forth in Appendix A to my testimony.

Q. Please describe your duties as assistant controller, corporate.

A. I am responsible for ensuring the accounting records of FirstEnergy and its subsidiaries are maintained in conformity with generally accepted accounting principles ("GAAP") and regulatory requirements, including the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USofA"). In addition, I am responsible for disbursements to vendors; external financial reporting; accounting research in connection with proposed business transactions; and cost analysis and accounting classification of construction projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain and support the level of pension and other post-employment benefits ("OPEB") expense Jersey Central Power & Light Company ("JCP&L" or "Company") is requesting for recovery in its base rate case filed with the Board of Public Utilities ("Board" or "BPU"), and to discuss related rate base adjustments.

Q. Please summarize your testimony.

A. My testimony discusses the following adjustments to pension and OPEB expense: (1) remove the 2019 pension and OPEB mark-to-market losses of $68 million and $1.8 million, respectively, recorded by JCP&L; and (2) include, for ratemaking purposes, the recalculated amount of the test-year pension and OPEB expense by amortizing the net accumulated actuarial loss over future periods. Based on these adjustments, JCP&L is requesting inclusion of $9.2 million of annual pension expense and $9.8 million of annual OPEB expense as part of the calculation of its revenue requirement in this base rate case.

To support the proposed level of pension and OPEB expense to be recovered in base rates, my testimony will provide background on the accounting for pension and OPEB costs under GAAP, including the two accounting methods prescribed by GAAP for the accounting of actuarial gains and losses – one of the six components of pension and OPEB costs. Finally, I will provide support for the adjustments necessary to determine the appropriate level of test year pension and OPEB expense for JCP&L, as well as the adjustments associated with the capitalized pension and OPEB costs in rate base.

II. JCP&L'S PENSION ACCOUNTING AND RATEMAKING

Q. How are pension and OPEB costs derived under GAAP?

A. Pension and OPEB costs consist of six components:

1. Service cost – Represents the actuarial present value of benefits attributed by the plan's benefit formula to services performed by employees during the reporting period.
2. Interest cost – Annual interest on the present value of the benefit obligations (liability) at the beginning of the year, using the same rate as the discount rate used to compute the present value of the obligations.

3. Estimated return on plan assets – Represents the estimated return on plan investments by applying the expected long-term rate of return to beginning-of-year plan asset balances.
4. Prior service cost amortization – Represents amortization, over the average remaining service period of employees, of changes to the benefit obligations due to plan amendments.
5. Actuarial gain/loss – Represents the net gain or loss resulting from a change in the value of plan assets and benefit obligations due to experience which differs from assumptions used to estimate the value of end-of-year plan asset and benefit obligation balances. Such differences can be related to the return on plan assets, changes in the discount rate used to calculate the present value of benefit obligations, and other assumptions such as mortality rates. As further described below, companies recognize actuarial gains and losses immediately in earnings ("mark-to-market accounting") or through delayed recognition whereby actuarial gains and losses are recorded in accumulated other comprehensive income ("AOCI"), a component of equity, and amortized into earnings over a future period.
6. Amortization of net transition asset or obligation – This component no longer applies to JCP&L because all transition assets and obligations have been fully amortized.

As noted in the description of cost component 5. above, companies have the option to recognize the earnings effect of actuarial gains and losses immediately or through delayed recognition. For companies that apply immediate recognition, the full amount of actuarial gains and losses are recognized in earnings immediately. For companies that apply delayed recognition, actuarial gains and losses are captured in AOCI and amortized over a future period. Therefore, the difference in the two "options" is simply a matter of timing with respect to earnings recognition with the delayed recognition method producing a less volatile level of gains or losses.

Q. What are actuarial gains and losses under GAAP?

A. Actuarial gains and losses represent the net gain or loss resulting from a change in the value of plan assets and benefit obligations due to experience which differs from assumptions used to estimate the end-of-year plan asset and benefit obligation balances.

In the case of plan assets, the difference between the actual return on plan investments during the year compared to the estimated return on plan investments (cost component 3. above) represents an actuarial gain (if the actual return is higher than the estimated return) or actuarial loss (if the actual return is lower than the estimated return) This component simply adjusts the expected return on plan assets in a given year to the actual return on plan assets in that year.

In the case of benefit obligations, a change in the assumed discount rate that measures the benefit obligation at the beginning of the year to the end of the year will result in an actuarial gain (if the actual discount rate is higher at the end of the year than the assumed discount rate at the beginning of the year) or an actuarial loss (if the actual discount rate at the end of the year is lower than the assumed discount rate at the beginning of the year). The present value of benefit obligations may also be affected by changes in assumed future payouts due to mortality experience that differ from assumed mortality rates, changes in assumed wage increases (in the case of pension costs), and changes in assumed health care inflation rates (in the case of OPEB benefits). If the present value of benefit obligations increases due to changes in actuarial assumptions, an actuarial loss will be incurred; conversely, if the present value of benefit obligations decreases due to actuarial assumption changes, an actuarial gain will be recognized. Actuarial gains or losses on plan assets are netted against actuarial gains or losses on benefit obligations to determine the net actuarial gain or loss for the plans for a given year.

Q. Please explain JCP&L's book accounting for pension and OPEB expense.

A. JCP&L's test year pension and OPEB expense is calculated in accordance with GAAP and is shown in Schedules TMA-1 and TMA-2, corresponding to Line 1 of Exhibit JC-4, Schedule CAP-2 (6+6), pages 11 and 12. In December of each year, FirstEnergy and its subsidiaries (including JCP&L) record actuarial gains or losses on their pension and OPEB plans to earnings through a mark-to-market adjustment (immediate recognition).

Q. What adjustments have been made to pension and OPEB expense?

A. Effective December 31, 2011, FirstEnergy and its subsidiaries (including JCP&L) made a one-time election to adopt mark-to-market accounting (immediate recognition) for their pension and OPEB plans ("Accounting Change"). As a result of the Accounting Change, JCP&L records a mark-to-market adjustment for actuarial gains or losses immediately to earnings in December of each year.

However, for ratemaking purposes in this base rate filing, JCP&L has removed the effect of this mark-to-market adjustment from GAAP pension/OPEB expense and replaced it with actuarial gains or losses calculated under the delayed recognition methodology. This calculation is consistent with the manner in which JCP&L calculated pension/OPEB costs in its 2016 base rate case.

Q. How were the adjustments and test year pension and OPEB expense calculated?

A. There are several steps to the calculation. First, the fiscal year 2019 net actuarial loss recorded by JCP&L is subtracted from the per-books level of expense. Then, under my direction, the Company's actuary calculated the amount of amortization of the accumulated net actuarial loss that would have been included in pension and OPEB expense under the delayed recognition methodology. An adjustment was then made representing the amount of amortization of the accumulated net actuarial loss calculated under the delayed recognition methodology.

Please refer to the Direct Testimony of Carol A. Pittavino (Exhibit JC-4), Schedule CAP-2 (6+6), pages 11 and 12, for the detailed calculations of the adjustments and proposed test year pension and OPEB expense, respectively.

Q. What level of pension and OPEB expense is JCP&L proposing to include in base rates?

A. The calculation results in an annual distribution pension expense of $9.2 million and an annual OPEB distribution expense of $9.8 million, which includes all applicable components of pension and OPEB expense discussed above, as shown in Exhibit JC-4, Schedule CAP-2 (6+6), pages 11 and 12, respectively.

Q. Will the emergence of FirstEnergy Solutions ("FES") from bankruptcy impact the amount of pension/OPEB expense that will be requested?

A. It may. Upon FES' emergence from bankruptcy, FirstEnergy will perform a remeasurement of the pension and OPEB plans, which may affect the level of pension and OPEB expense for the six months ended June 30, 2020. If FES exits bankruptcy during the test year of this matter, JCP&L will provide updated schedules when the adjustments to pension and OPEB expense are known.

Q. Are there any additional justifications for JCP&L's pension and OPEB expense methodology?

A. JCP&L has included pension and OPEB expense in its income statement for ratemaking purposes using the delayed recognition method. Under this methodology, pension and OPEB mark-to-market expense is amortized over a future period. The effect of the delayed recognition methodology is to amortize the mark-to-market expense over a period of approximately 11 years. Expenses in the income statement have a dollar for dollar impact on the Company's revenue requirement. Use of the delayed recognition methodology is designed to reduce the volatility in the level of pension and OPEB costs from year-to-year resulting from JCP&L's election to record actuarial gains and losses on a mark-to-market basis, and instead recognize the impact of actuarial gains and losses on JCP&L's pension and OPEB costs over future periods (delayed recognition). The adjustment is beneficial to JCP&L's ratepayers because reducing the volatility of actuarial gains and losses lessens the fluctuation of retail rates.

Q. Does the Company make a similar adjustment to the capitalized portion of pension and OPEB costs?

A. No. With respect to capitalized pension and OPEB costs, JCP&L has previously included the capitalized portion of pension and OPEB costs in rate base in the year the expense occurs using the immediate recognition method. As described further below in my testimony, JCP&L is proposing an adjustment to rate base to reflect the delayed recognition method for the capitalized portion of pension and OPEB mark-to-market costs.

Q. Does the use of the immediate recognition method result in greater additions to rate base each year?

A. No, it does not. As you can observe in Schedule TMA-3, Attachment B, to my testimony, about half of the time, 3 out of 7 years, immediate recognition results in reductions to rate base. Actuarial gains and losses are largely impacted by market performance, which are not predictable.

Q. Is JCP&L proposing any other adjustments related to pension and OPEB costs?

A. Yes. JCP&L is proposing a reduction to rate base of $40.2 million. This consists of a reduction to capitalized pension costs in rate base of $39.1 million, and a reduction to capitalized OPEB costs in rate base of $1.2 million.

Q. Do these rate base adjustments follow the Financial Accounting Standards Board ("FASB") Accounting of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost, as amended on January 1, 2018?

A. Yes. JCP&L (and FirstEnergy) adopted the FASB Accounting Standards Update ("ASU") 2017-07 on January 1, 2018, which amended certain accounting rules addressing the presentation for pension and OPEB service and non-service costs for income statement purposes. Upon adoption, JCP&L (and FirstEnergy) revised its capitalization policy regarding pension and OPEB costs to only capitalize a portion of service costs. All remaining pension and OPEB costs are recognized in earnings. This practice is consistent with the FASB's amended accounting rules as well as the FERC's USofA.

Prior to JCP&L's adoption of ASU 2017-07 on January 1, 2018, all pension/OPEB costs (including the mark-to-market adjustment) were subject to capitalization under JCP&L's then-current capitalization policy – resulting in a portion of each mark-to-market adjustment from 2011 through 2017 being capitalized into rate base. JCP&L has included an adjustment to rate base to address the timing differences between the calculation of pension and OPEB expense and rate base under the immediate and delayed recognition methodologies for the portion of pension/OPEB costs capitalized in rate base during the period 2011-2017. The appropriate rate base adjustment is reflected in this case.

Q. Why is it necessary to make an adjustment to rate base to adjust for the timing differences of the immediate recognition and the delayed recognition methodologies?

A. The difference in the delayed recognition methodology and the immediate recognition methodology is a matter of timing of the recognition of pension and OPEB costs. With the accounting change in 2018, all pension and OPEB costs are to be expensed, except for a portion of current period service costs, which are to be capitalized. Therefore, to properly reflect pension and OPEB expense in the income statement beginning in 2018, JCP&L must adjust the pension and OPEB costs recognized in rate base between 2011 through 2017 to eliminate the timing differences between the recognition of pension and OPEB cost in rate base and the recognition of pension and OPEB expense in the income statement.

Q. Please explain how the adjustment was calculated.

A. The effect of the calculation is to adjust rate base to the level of capitalized pension and OPEB costs under the delayed recognition method instead of the immediate recognition method.

First, for the period January 1, 2011 through December 31, 2017, the Company compared the amounts of capitalized actuarial gains/losses as calculated by its actuary under the delayed recognition methodology to the amounts of capitalized actuarial gains/losses actually recorded under the immediate recognition method for regulatory purposes (See Schedule TMA-3, Attachment B for pension and Attachment D for OPEB). Referring to Schedule TMA-3, Attachment B, capitalized actuarial gains/losses under the delayed recognition methodology are shown in Column C. Column D reflects the Company's per books actuarial gains/losses capitalized in rate base using the immediate recognition methodology. The result in Column E is the difference between capitalized actuarial gains/losses under the delayed recognition methodology and the capitalized actuarial gains/losses recorded under immediate recognition.

Schedule TMA-3, Attachment C, calculates annual and cumulative book and tax depreciation for each annual capitalization adjustment. The results from the book and tax depreciation tables are used in the calculation of the associated accumulated deferred income taxes (ADITs) on the bottom of Schedule TMA-3, Attachment C, for pension and on Schedule TMA-3, Attachment E, for OPEB.

Schedule TMA-3, Attachment A, summarizes the calculation of the decrease to rate base for capitalized pension costs of $39.1 million. The resulting rate base adjustment at June 30, 2020 on Schedule TMA-3, Attachment A, for capitalized OPEB costs is a decrease to rate base of $1.2 million. The total adjustment results in a decrease to rate base of $40.2 million.

Q. Why does the adjustment only cover the period from January 1, 2011 through December 31, 2017?

A. This adjustment covers the period from the effective date of JCP&L's accounting election to report pension and OPEB expense for GAAP purposes using the immediate recognition methodology, which began on January 1, 2011, through the adoption of the FASB Accounting Standards Update 2017-07 on January 1, 2018. This is the period JCP&L capitalized pension and OPEB actuarial gains/losses using the immediate recognition method.

Q. Does this calculation have to be made in future base rate cases?

A. Yes. The calculation should be made until the rate base adjustment is $0 or is otherwise determined to be immaterial.

IV. CONCLUSION

Q. Please summarize your direct testimony.

A. JCP&L's proposed adjustments to test year pension and OPEB expense are appropriate to: (1) eliminate the impact on JCP&L's rates of the mark-to-market accounting for pension and OPEB costs used for financial reporting purposes; and (2) appropriately reflect pension and OPEB costs for ratemaking purposes by amortizing net actuarial losses over future periods. In addition, JCP&L's adjustments related to capitalized pension and OPEB costs accurately reflect the timing differences between the immediate and delayed recognition methodologies in rate base.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Appendix A

Experience and Education

My name is Tracy Ashton and my business address is 76 South Main Street, Akron, Ohio 44308. I am employed by FirstEnergy Service Corporation as Assistant Controller, Corporate. I am responsible for ensuring that the financial and accounting records of FirstEnergy and its subsidiaries are maintained in conformity with generally accepted accounting principles and regulatory accounting requirements. I am also responsible for disbursements to employees, tax authorities and vendors; external financial reporting; accounting research in connection with proposed accounting standards and proposed business transactions; and cost analysis and accounting classification of construction projects.

From May 2008 to May 2019, I served in various position within the finance organization including manager of Financial Reporting and Technical Accounting and Director of Business Planning and Performance, prior to being promoted into my current role. From 2003 to 2008, I was with Deloitte & Touche, LLP where I served in various client service positions.

I received a Bachelor of Business Administration degree in Accounting from Kent State University. I am a licensed certified public accountant in Ohio. In addition to this testimony, I have provided expert testimony before the Public Utilities Commission of Ohio for the Ohio Significantly Excessive Earnings Test, Docket # 19-1338-EL-UNC.

JERSEY CENTRAL POWER & LIGHT COMPANY
Pension Normalization

Adjustment to Test Year pension expense to reflect actuarial gains/losses under the delayed recognition accounting methodology.

Line No.	Description	12 ME June 30 2020 Amount
1	Pension expense per books [(a)]	$ 38,113,428
2	Remove test year pension M-t-M expense for actuarial gains/losses [(a)]	$ (68,048,327)
3	Test year pension credit excluding M-t-M for actuarial gains/losses [(a)]	$ (29,934,899)
4	Add test year pension expense for actuarial gains/losses using delayed recognition accounting methodology [(a)]	$ 39,991,065
5	Total test year pension expense (Line 3 + Line 4) [(a)]	$ 10,056,166
6	Distribution allocation percentage based on 2015 distribution S&W	91.38%
7	Total requested distribution pension expense (Line 5 x Line 6)	$ 9,189,324
8	Total distribution pension expense without M-t-M adjustment (Line 1 x Line 6)	$ 34,828,051
9	Reduction in requested distribution pension expense due to M-t-M adjustment (Line 8 - Line 7)	$ 25,638,726

(a) - Represents legal entity (Distribution and Transmission) results

JERSEY CENTRAL POWER & LIGHT COMPANY
OPEB Normalization

Adjustment to Test Year OPEB expense to reflect actuarial gains/losses under the delayed recognition accounting methodology.

Line No.	Description	12 ME June 30 2020 Amount
1	OPEB expense per books [a]	$ 2,869,574
2	Remove test year OPEB M-t-M expense for actuarial gains/losses [a]	$ (1,824,284)
3	Test year OPEB expense excluding M-t-M for actuarial gains/losses [a]	$ 1,045,290
4	Add test year OPEB expense for actuarial gains/losses using delayed recognition accounting methodology [a]	$ 9,677,673
5	Total test year OPEB expense (Line 3 + Line 4) [a]	$ 10,722,963
6	Distribution allocation percentage based on 2015 distribution S&W	91.38%
7	Total requested distribution OPEB expense (Line 5 x Line 6)	$ 9,798,644
8	Total distribution OPEB expense without M-t-M adjustment (Line 1 x Line 6)	$ 2,622,217
9	Increase in requested distribution OPEB expense due to M-t-M adjustment (Line 8 - Line 7)	$ (7,176,427)

(a) - Represents legal entity (Distribution and Transmission) results

Jersey Central Power & Light

Calculation of Rate Base Adjustment

Schedule TMA- 3 Attachment A

	Pension	OPEB	Total
Capitalized Costs	($66,996,742)	($1,895,268)	($68,892,010)
Accumulated depreciation	12,542,738	174,105	12,716,844
Accumlated Deferred Income Taxes	15,401,372	562,979	15,964,351
Increase / (Decrease) to Rate Base	($39,052,631)	($1,158,184)	($40,210,815)
Authorized Return on Rate base	9.16%	9.16%	9.16%
Adjustment to Revenue Requirement	($3,577,221)	($106,090)	($3,683,311)

JC Pension Actuarial (Gain) / Loss

Schedule TMA - 3 Attachment B

	A	B	C = A - B	D	E = C - D
	Delayed Recognition			Immediate Recognition	Capitalized Adjustment
	Total	Income Statement	Capitalized	Capitalized	Increase / (Decrease)
2011	$26,415,000	$6,976,202	$19,438,798	$41,938,787	($22,499,989)
2012	$26,646,800	$11,220,967	$15,425,833	$34,172,525	($18,746,692)
2013	$28,781,700	$10,217,503	$18,564,197	$38,571	$18,525,626
2014	$26,888,400	$10,427,322	$16,461,078	$81,652,726	($65,191,648)
2015	$35,193,800	$13,451,070	$21,742,730	$41,468,467	($19,725,737)
2016	$38,052,800	$15,160,236	$22,892,564	$3,067,499	$19,825,065
2017	$35,027,100	$14,935,555	$20,091,545	($725,088)	$20,816,633
				Total	($66,996,742)

JC Pension - Depreciation and Accumulated Deferred Income Taxes

Schedule TMA -3 Attachment C

Book Depreciation	
Deprec Rate 2010-2014	2.17%
Deprec Rate 2015 (blended)	2.00%
Deprec Rate 2016-2018	1.94%
2011-2017 Tax Rate	35.00%
2018-2020 Tax Rate	21.00%

	Capitalized Adjustment Increase / (Decrease)	Book Depreciation										
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
2011	($22,499,989)	$244,125										$244,125
2012	(18,746,692)	488,250	203,402									691,651
2013	18,525,626	488,250	406,803	(201,003)								694,050
2014	(65,191,648)	488,250	406,803	(402,006)	707,329							1,200,376
2015	(19,725,737)	488,250	406,803	(402,006)	1,414,659	197,011						2,104,716
2016	19,825,065	488,250	406,803	(402,006)	1,414,659	394,022	(192,303)					2,109,424
2017	20,816,633	488,250	406,803	(402,006)	1,414,659	394,022	(384,606)	(201,921)				1,715,200
2018	-	488,250	406,803	(402,006)	1,414,659	394,022	(384,606)	(403,843)	-			1,513,278
2019	-	488,250	406,803	(402,006)	1,414,659	394,022	(384,606)	(403,843)	-	-		1,513,278
6/30/20	-	244,125	203,402	(201,003)	707,329	197,011	(192,303)	(201,921)	-	-	-	756,639
											2011-2017	$8,759,543
											2018-2020	$3,783,196

	Capitalized Adjustment Increase / (Decrease)	Tax Depreciation - MACRS with Bonus Depreciation										
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
2011	($22,499,989)	$22,499,989										$22,499,989
2012	(18,746,692)	-	9,724,846									9,724,846
2013	18,525,626	-	676,662	(9,610,168)								(8,933,506)
2014	(65,191,648)	-	625,858	(668,682)	33,818,167							33,775,343
2015	(19,725,737)	-	578,992	(618,478)	2,353,093	10,232,726						12,546,333
2016	19,825,065	-	535,499	(572,164)	2,176,423	712,000	(10,284,252)					(7,432,494)
2017	20,816,633	-	495,381	(529,185)	2,013,444	658,544	(715,586)	(10,798,628)				(8,876,030)
2018	-	-	458,169	(489,540)	1,862,199	609,229	(661,860)	(751,376)	-			1,026,821
2019	-	-	423,863	(452,766)	1,722,689	563,466	(612,297)	(694,963)	-	-		949,992
6/30/20	-	-	418,239	(418,864)	1,593,284	521,253	(566,303)	(642,922)	-	-	-	904,687
											2011-2017	$53,304,481
											2018-2020	$2,881,500

Accumulated Deferred Income Taxes (ADIT)					
	A	B	C = B - A	D	E = C * D
	Depreciation				
	Book	Tax	Difference	Tax Rate	ADIT
2011-2017	$8,759,543	$53,304,481	$44,544,938	35.00%	$15,590,728
2018-2020	$3,783,196	$2,881,500	($901,696)	21.00%	($189,356)
Total	$12,542,738	$56,185,981	$43,643,243		$15,401,372

	A	B	C = A - B	D	E = C - D
	Delayed Recognition			Immediate Recognition	Capitalized Adjustment
	Total	Income Statement	Capitalized	Capitalized	Increase / (Decrease)
2011	$16,130,200	$4,568,073	$11,562,127	$13,558,928	($1,996,801)
2012	$16,846,900	$7,094,230	$9,752,670	$14,304,677	($4,552,007)
2013	$17,435,900	$6,189,744	$11,246,156	($1,902,234)	$13,148,390
2014	$15,504,700	$6,012,723	$9,491,977	$13,551,904	($4,059,927)
2015	$15,607,600	$5,965,225	$9,642,375	$11,953,689	($2,311,314)
2016	$15,714,500	$6,260,657	$9,453,843	$15,026,164	($5,572,321)
2017	$16,209,200	$6,911,603	$9,297,597	$5,848,885	$3,448,712
				Total	($1,895,268)

Book Depreciation	
Deprec Rate 2010-2014	2.17%
Deprec Rate 2015 (blended)	2.00%
Deprec Rate 2016-2018	1.94%
2011-2017 Tax Rate	35.00%
2018-2020 Tax Rate	21.00%

	Capitalized Adjustment Increase / (Decrease)	Book Depreciation 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
2011	($1,996,801)	$21,665										$21,665
2012	(4,552,007)	43,331	49,389									92,720
2013	13,148,390	43,331	98,779	(142,660)								(551)
2014	(4,059,927)	43,331	98,779	(285,320)	44,050							(99,161)
2015	(2,311,314)	43,331	98,779	(285,320)	88,100	23,084						(32,026)
2016	(5,572,321)	43,331	98,779	(285,320)	88,100	46,168	54,052					45,109
2017	3,448,712	43,331	98,779	(285,320)	88,100	46,168	108,103	(33,453)				65,709
2018	-	43,331	98,779	(285,320)	88,100	46,168	108,103	(66,905)	-			32,256
2019	-	43,331	98,779	(285,320)	88,100	46,168	108,103	(66,905)	-	-		32,256
6/30/20	-	21,665	49,389	(142,660)	44,050	23,084	54,052	(33,453)	-	-	-	16,128
											2011-2017	$93,465
											2018-2020	$80,640

	Capitalized Adjustment Increase / (Decrease)	Tax Depreciation - MACRS with Bonus Depreciation 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
2011	($1,996,801)	$1,996,801										$1,996,801
2012	(4,552,007)	-	2,361,354									2,361,354
2013	13,148,390	-	164,305	(6,820,727)								(6,656,422)
2014	(4,059,927)	-	151,969	(474,591)	2,106,087							1,783,465
2015	(2,311,314)	-	140,589	(438,959)	146,543	1,198,994						1,047,167
2016	(5,572,321)	-	130,028	(406,088)	135,541	83,427	2,890,642					2,833,550
2017	3,448,712	-	120,287	(375,584)	125,391	77,163	201,133	(1,789,019)				(1,640,629)
2018	-	-	111,251	(347,446)	115,972	71,385	186,032	(124,481)	-			12,713
2019	-	-	102,921	(321,347)	107,284	66,023	172,101	(115,135)	-	-		11,847
6/30/20	-	-	101,555	(297,285)	99,225	61,076	159,173	(106,513)	-	-	-	17,231
											2011-2017	$1,725,286
											2018-2020	$41,791

Accumulated Deferred Income Taxes (ADIT)	A	B	C = B - A	D	E = C * D
	Depreciation				
	Book	Tax	Difference	Tax Rate	ADIT
2011-2017	$93,465	$1,725,286	$1,631,821	35.00%	$571,137
2018-2020	$80,640	$41,791	($38,849)	21.00%	($8,158)
Total	$174,105	$1,767,077	$1,592,972		$562,979

EXHIBIT JC-7

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Dennis L. Pavagadhi

Re: Distribution Operations, Capital Expenditures, O&M Expenses and Proposed Changes to Tariff Appendix A Charges

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Dennis L. Pavagadhi. My business address is 300 Madison Avenue, Morristown, New Jersey 07962-1911. I also have an office at 101 Crawford Corner Rd. Building #1, Suite 1-511, Holmdel, New Jersey 07733, the Company's Central Region headquarters.

Q. Please identify your employer and describe your current position.

A. I am employed by Jersey Central Power & Light Company ("JCP&L" or "Company") as Director, Operations Services. In this capacity I report to the JCP&L Vice President, Operations. My responsibilities include leading the JCP&L's lines organization, the Engineering department, and the Claims department. My qualifications and experience are set forth in detail in Appendix A attached to this testimony.

Q. Have you previously testified in Board of Public Utilities ("Board" or "BPU") proceedings?

A. Yes. Most recently, in 2018 and 2019, I provided testimony in the Company's Infrastructure Investment Program ("IIP") filing in BPU Docket No. EO18070728 (the "JCP&L Reliability Plus Proceeding"). In addition, I provided pre-filed testimony in in *I/M/O the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Services, and for Approval of Other Proposed Tariff Revisions in Connection Therewith* ("2016 Base Rate Filing") at BPU Docket No. ER16041383, which was settled prior to hearings. Earlier, I also testified in the Company's 2012 base rate filing in BPU Docket No. ER12111052. I have also testified on behalf of the Company in other proceedings such as before Land Use and Planning Boards for zoning and variance approvals for distribution and sub-transmission projects

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to provide support for the base rate case filing by addressing the capital investments and the operations and maintenance ("O&M") expenses associated with operating, maintaining and managing the electric distribution system, to provide safe, adequate and proper service to the Company's customers. In addition, in support of the recovery of the accumulated deferred storm damage costs, I also discuss the Company's robust storm process to address the storm and weather events that have impacted JCP&L's service territory and given rise to those significant deferred costs. Finally, I provide support for the proposed changes being made to some of the charges in Appendix A of the Company's Tariff and provide support for those proposed changes.

Q. Please summarize your testimony.

A. JCP&L has a very distinct service territory in terms of its size, topography and configuration (as two non-contiguous regions), which together are unique among New Jersey' electric public utilities, and which present challenges that can and do impact the reliability of system performance. The Company's over $1 billion in capital investment, including its IIP investments and capitalized storm costs, since January 1, 2016, and the $135 million of O&M expenditures in the July 1, 2019 to June 30, 2020 test year (the "Test Year"), reflect JCP&L's commitment to providing safe and reliable service to its customers within its large and diverse service territory. This commitment is met using a dedicated work force that carries out the Company's comprehensive inspection and maintenance ("I&M") programs and processes, including its relentless vegetation management program. Moreover, as the Company's experience suggests is increasingly necessary, JCP&L also deploys its dedicated work force, oftentimes together with human and other resources from across the large FirstEnergy holding company system and from other mutual assistance resources to which it has access, to implement its robust storm recovery and restoration process using its dynamic incident command system ("ICS") structure. The Company's storm processes and programs comply with industry standards and the increasing host of the Board's regulatory requirements, which are evolving to address the lessons-learned from the violent and/or intense weather systems that have left their mark on the State of New Jersey, generally, and on JCP&L's service territory, in particular. The Company's storm experience since 2016 has resulted in significant growth in the Company's storm cost deferral to over $300 million, which represents prudently incurred costs to prepare for, pre-stage, when necessary, and to carry out the storm recovery and restoration processes, and which the Company seeks to recover in this proceeding. Through its I&M program and storm process implementation and the overall professional management of its electric system, the Company meets the Boards system performance criteria. Finally, the Company's proposed changes to the Appendix A pricing in the Tariff are justified on the basis of updated analysis of the costs for providing the relevant materials and services to customers as set forth in Appendix A, which has not been updated since the Company's 2016 Base Rate Filing.

Q. How is your testimony organized?

A. My testimony is organized as follows:

II. JCP&L's ELECTRIC DISTRIBUTION SYSTEM

Q. Please describe JCP&L's electric distribution system.

A. I begin by noting that Company President, Mr. Fakult, in his overview testimony (Exhibit JC-2), has already described and explained the scope of the Company's service territory and the Company's electric system by which the Company provides electric distribution service to approximately 1.1 million residential, commercial and industrial customers, representing approximately 25% of the metered electric customers in New Jersey.

Q. Do you have anything to add?

A. Yes. Let me add some additional detail to Mr. Fakult's description. The Company owns, operates and maintains over 35,000 conductor miles of primary distribution circuits, over 1,800 circuit miles (5,469 conductor miles) of sub-transmission circuits, in excess of 340,000 JCP&L-owned poles and approximately 250,000 transformers. JCP&L owns, operates and maintains 339 substations, 244 sub-transmission circuits and 1,162 primary distribution circuits.

The JCP&L distribution system is mainly a 12.47 kV multi-grounded wye system. Circuits operating at this voltage make up about 55% of the distribution circuits throughout JCP&L. Other primary voltages include 4.16 kV wye, 4.8 kV delta, and 34.5 kV wye.

Q. Are there other aspects of the JCP&L's electric distribution system you would like to explain?

A. Yes. I would like to address some of the unique features of the Company's service territory. To begin, it is vast and diverse in terms of customer demographics and terrain. The territory encompasses 3,300 square miles, covering approximately 43% of New Jersey's land mass, in all or parts of 13[1] of New Jersey's 21 counties and 236 municipalities (or about 45% of all New Jersey municipalities). As described by Mr. Fakult, the service territory is made up of two non-contiguous regions. Electrically, this unique configuration means that the two regions are managed as one electric system but, technically, must be operated separately as a consequence of the non-contiguity. This imposes limits, which might not be present in a contiguous situation, on the Company's ability to engineer circuit ties as a component of managing system reliability. In addition, the load shift from winter to summer in the Central Region, especially at its shore communities (where and when the population significantly expands), are addressed differently from the Northern Region in the Company's planning criteria. The distance between the two regions also adds time to the process of providing inter-regional mutual assistance when such assistance is necessary.

[1] That is, (in alphabetical order) Burlington, Essex, Hunterdon, Mercer, Middlesex, Monmouth, Morris, Ocean, Passaic, Somerset, Sussex, Union and Warren Counties.

Forestation is another important feature of the service territory. New Jersey is a heavily forested State with forests covering about 40-45% of the land mass of the State.[2] To grasp the uniqueness of the JCP&L service territory, it helps to understand that New Jersey's

> "forested areas are not distributed evenly across the State. Sussex County is the most heavily forested (68 percent); Essex, Hudson, and Union Counties are the least forested. Generally, forests are concentrated in the northernmost portion of the State and in the Pine Barrens in Atlantic, Burlington, and Ocean, Counties in the south. Portions of the Pine Barrens also extend into the less forested counties of Camden, Cumberland, Cape May, and Gloucester."[3]

Indeed, the JCP&L service territory includes two distinct regions of New Jersey: the Northern Region, which includes the heavily-forested northwestern portion of New Jersey in Sussex, Hunterdon, Warren, Passaic, Morris, Somerset, Middlesex, Mercer, Essex and Union Counties; and the Central Region in the central coastal portion of the State, in Burlington, Monmouth, and Ocean Counties, which were further described in Mr. Fakult's direct testimony (Exhibit JC-2). The following figures present a graphic depiction of this kind of data:

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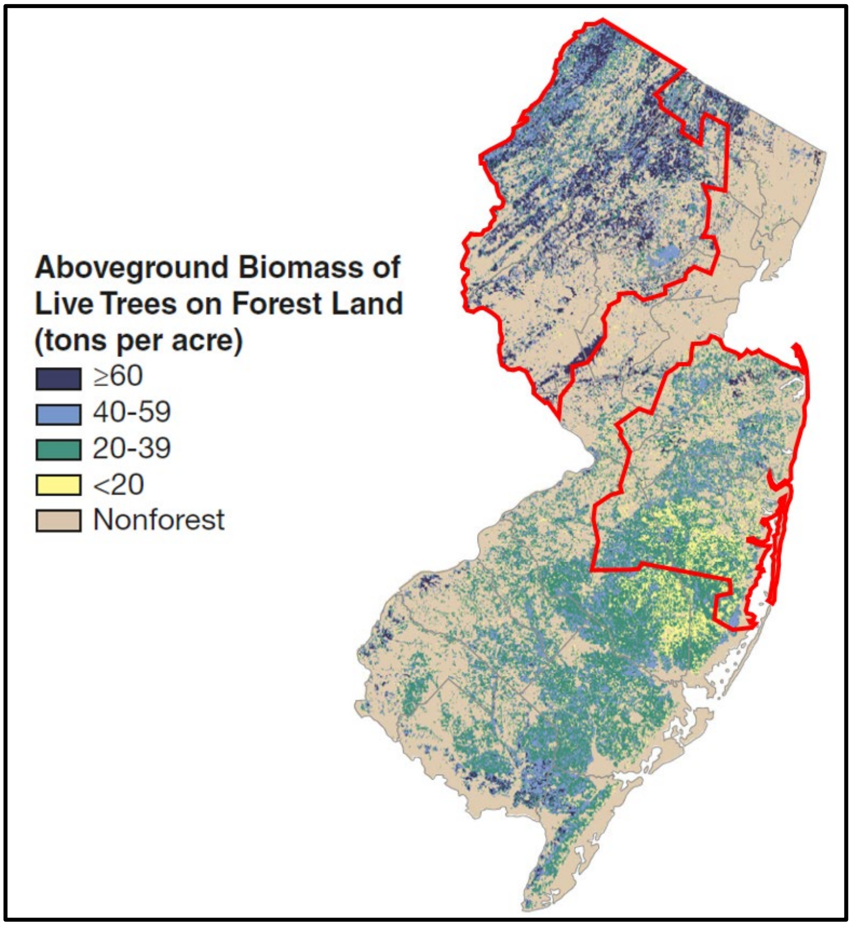
[2] Widmann, Richard H. 2005. Forests of the Garden State, Resource Bull. NE-163. Newtown Square, PA: U.S. Department of Agriculture, Forest Service, Northeastern Research Station, at p. 1. Found at: https://www.fs.fed.us/ne/newtown_square/publications/resource_bulletins/pdfs/2005/ne_rb163.pdf. **See**, also, Forests of New Jersey, 2018 found at: https://www.fs.usda.gov/treesearch/pubs/58739.
[3] Id. at p.4.

Figure 1[4]



Q. Is there any other feature of the service territory that you would like to explain?

A. Yes. The highest elevations in the State are found in northern New Jersey and specifically coincide with the Company's Northern Region, and which, as explained by Company witness, Mr. Workoff, a Company meteorologist (Exhibit JC-8), experiences approximately twice the snowfall and incidents of freezing rain as compared to the rest of New Jersey.

[4] Crocker, Susan J., et al, New Jersey Forests 2013, U.S. Forest Service, Resource Bulletin NRS-109, January 2017 at p. 15.

Q. What is the significance of this additional information regarding the scope and scale of the JCP&L service territory and its other unique characteristics such as elevation, coastal exposure, and forestation?

A. This information provides context helpful in understanding the relationship between the variable topography of the State and the challenges these features present to the operation of the electric system within the Company's expansive and diverse service territory. In addition, this information serves as a backdrop in considering the evolving views within New Jersey on the topic of "climate change."

Q. Can you elaborate?

A. Yes, I can. In this regard, it may help to refer to views expressed by Board President Fiordaliso in January 2018 when he stated:

> What climate change really means is extremes…... And we've noticed more severe storms, more variation in temperatures.[5]

I can also refer to the views of the current State administration. For instance, in June of 2019, Governor Murphy stated that "climate change and sea level rise affect us all, and as a coastal state, New Jersey is especially vulnerable to the impacts of global warming" as he announced New Jersey's return to the Regional Greenhouse Initiative ("RGGI").[6]

More recently, on October 29, 2019, the Governor also signed Executive Order No. 89 to establish a Statewide Climate Change Resilience Strategy, which will include, among other things, measures to address "long-term water and energy resource security" and

[5] Available at: https://morristowngreen.com/2018/01/14/combating-climate-change-is-a-moral-obligation-bpu-commissioner-tells-morristown-audience/.
[6] Available at: https://www.nj.gov/governor/news/news/562019/approved/20190617a.shtml.

"increased vulnerability to extreme temperatures."[7] Among, other things, Executive Order No. 89 states:

> the scientific community has reached an overwhelming consensus that due to increasing atmospheric levels of carbon dioxide and other greenhouse gases from human activities, the Earth is warming, and temperature increases are contributing to an increase in the frequency and intensity of severe weather events, precipitation, and wind damage, as well as rising sea levels;… (emphasis added).[8]

In establishing the Climate and Flood resilience Program, the Executive Order directs the newly established Chief Resiliency Officer within 180 days to:

> Develop a Scientific Report on Climate Change based on existing data and the best available science regarding the current and anticipated environmental effects of climate change in New Jersey, including but not limited to increased temperatures, sea level rise, increased frequency or severity of rainfall, storms and flooding, increased forest fires, and increased frequency and severity of droughts, anticipated by scientists at least through 2050; (emphasis added)[9]

In this regard, I also refer you to Mr. Workoff's testimony (Exhibit JC-8). From my perspective, consideration of the data about the JCP&L service territory's geographic expanse and diversity, the degree of its forestation relative to the rest of the State, and the State's increasing experience with, and concerns about, the impacts of climate change provide a useful perspective from which to consider the Company's investment of capital, O&M expenses, deferred storm costs, operations, maintenance and performance (including storm recovery and restoration), which I will be discussing herein.

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[7] Available at: https://www.nj.gov/governor/news/news/562019/approved/20191029a.shtml.
[8] Id., at p.1.
[9] Id., at p.2.

III. DISTRIBUTION OPERATIONS AND ORGANIZATIONAL SUPPORT SERVICES

Q. In Mr. Fakult's Testimony (Exhibit JC-2), he describes the JCP&L Distribution Operations organization. Do you have anything to add?

A. Mr. Fakult's description of the organization is complete and accurate and it is my privilege to be part of the organization and a part of its leadership team.

Q. With Mr. Fakult's organizational description as the background then, does JCP&L receive support from corporate organizations elsewhere in the FirstEnergy holding company system?

A. Yes. The Company receives support services from various FirstEnergy corporate departments within the Service Company. One significant source of this support comes from the FirstEnergy Service Company Distribution Support function, which also provides similar support services for key functions used by the other FirstEnergy utilities.

These services include administration of the outage management system, which is the system that tracks customer outage; employing a workforce development department to provide various training programs and materials to operating companies' staff; and employing the work management department that focuses on facilitating productivity improvements through the introduction of methods and technologies, such as the now fully deployed mobile data computing terminals used to enhance productivity and customer service of work crews. Although not directly relevant to my testimony in this distribution base rate proceeding, for a fuller perspective about the extent of the Company's operations, I'll mention that JCP&L also receives services through other Service Company functions to monitor and operate the JCP&L-owned bulk transmission system, which is operationally controlled by PJM Interconnection LLC, under the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Q. What other services does Distribution Support provide?

A. The Distribution Support organization has skilled engineers to provide a wide range of technical and training support, and a vegetation management department to provide distribution program oversight and transmission vegetation management expertise.

Distribution Support also establishes and maintains the baseline minimum standards for the I&M practices to which JCP&L and the other FirstEnergy utilities adhere with respect to these activities. JCP&L is able to take advantage of Distribution Supports' technical support and guidance where needed. This includes support services related to the execution of the Company's programs, coordination of best practices' discussions across the FirstEnergy system, and taking advantage of its large knowledge base, which assists in arriving at solutions for various system performance challenges. JCP&L is also able to take advantage of having Distribution Support employees readily available to provide assistance when severe weather strikes. This includes leadership and office support, as well as field support in roles such as hazard response.

Q. Does JCP&L get support from its affiliated FirstEnergy utilities?

A. Yes. Because of the size and structure of FirstEnergy, JCP&L has access to restoration personnel and other valuable resources from the nine other FirstEnergy utilities. This direct access to FirstEnergy workforce and equipment resources enhances JCP&L's ability to restore service to customers, particularly at times when mutual assistance resources are spread thin or are difficult to access in a short period of time. This latter assistance is typically arranged in the context of the Company's storm management process and under the leadership of the designated Incident Commander, if one has been designated for a particular event under the Company's ICS structure, in coordination with the Manager of Emergency Preparedness.

Q. Is there anything else that you think would help to better understand JCP&L's organizational structure?

A. JCP&L is not only committed to providing safe and reliable service, but it is also aligned with employees in the several states in which FirstEnergy operates to support the overall success of FirstEnergy. In this regard, just as JCP&L receives workforce and equipment support from its affiliate companies in times of storms and other emergencies, JCP&L provides similar assistance to its affiliate companies and other electric distribution companies ("EDCs") when the need arises and when JCP&L has the ability to do so (and after JCP&L customers have been restored).

IV. ELECTRIC DISTRIBUTION CAPITAL INVESTMENTS

Q. Can you briefly describe the capital budgeting process?

A. JCP&L follows a rigorous standardized FirstEnergy capital budgeting process. Capital requests by JCP&L are based on individual programs or projects identified by JCP&L business units and submitted in the capital allocation process, which includes three rounds of presentation and review, with significant technical review and input from knowledgeable corporate and affiliated FirstEnergy utility experts regarding the most appropriate use of capital. The corporate technical review process helps to provide a common perspective across all FirstEnergy utilities. The annual capital prioritization process includes an initial target spending level based on historical spend. Building from that starting point, the actual budget emerges through the iterative, structured and standardized process of three rounds of review to address and meet reliability and other JCP&L targets and objectives for the coming year.[10]

Q. Can you provide some insight into how the process works at JCP&L?

A. Yes. Each year JCP&L conducts a thorough review of all proposed capital projects. Potential projects are classified, prioritized and sub-prioritized. Mandatory projects are given the highest priority, generally followed by reliability, condition, and value-added projects, in that order. Priority rankings are confirmed for each project by a cross-functional peer review team from across FirstEnergy, to ensure appropriate consistency among the FirstEnergy utilities, as indicated above. This review process ensures that (i) the necessary engineering rigor regarding problem solving approach and project justification has occurred, (ii) the project scope and cost estimates have been thoroughly developed, and (iii) the anticipated benefits are accurately represented.

Q. How much has JCP&L invested in its distribution system since 2016?

A. JCP&L's total capital expenditure was $1.028 billion from January 1, 2016 through June 30, 2020. Approximately $162.9 million of these expenditures are related to capitalized storm costs and approximately $63.8 million for the IIP (*i.e.*, the JCP&L Reliability Plus program), which are further addressed in the testimonies of Mark A. Mader (Exhibit JC-3) and Carol A. Pittavino (Exhibit JC-4).

Table 1 below identifies the Company's total actual capital spending on its distribution system for the period January 1, 2016 – December 31, 2019 and the projected

[10] In making decisions regarding investment in discretionary capital (such as with respect to the Reliability Plus program discussed later herein), one of the factors that FirstEnergy considers is the cost recovery mechanisms available to its utilities.

spending during the first six months of 2020, which will be updated to actuals as the case proceeds.

Table 1

Year	2016	2017	2018	2019	January 1 - June 30, 2020
Capital Expenditures (millions)	$208.2	$191.0	$253.9	$255.4	$119.5

Q. Can you describe the capital improvements JCP&L has made to its system since 2016?

A. Yes. Since 2016, JCP&L has made many capital improvements to its system, including the following projects:

Barrier Island rebuild project – Following the devastating impact of Hurricane Sandy on the New Jersey Barrier Island, JCP&L initiated a project to reinforce its infrastructure serving the region that was predominantly undertaken with planning and engineering beginning in 2015, and implementation commencing in 2016 through completion in 2018. In addition to raising infrastructure by installing hundreds of new, taller poles, JCP&L safely repositioned the primary conductor from many areas on the Barrier Island to allow for the elevation of houses without dangerous encroachment into energized facilities. The scope of these projects also included: moving equipment, such as transformers, from less accessible back-lot locations to more accessible street locations; and increasing the height of the utility poles and replacing primary conductors with secondary conductors improving access to and the serviceability of, back-lot line sections. This work integrated improved restoration effectiveness into the design, planning and construction of JCP&L's distribution system. This initiative was completed in 2018.

Substation flood mitigation project – As part of its storm hardening efforts, JCP&L made improvements at several substations to mitigate the risk of flood damage. Depending on the unique circumstances of each location, different mitigation techniques were utilized, including various types of flood walls, raising equipment above historical flood levels, and installation of video feeds and flood sensors for real-time remote monitoring at 19 substations.

Manchester substation capacity project – As a result of significant load growth in Ocean County, JCP&L initiated a project to install an additional transformer and switchgear at its Manchester substation, which it expects to have in-service during 2020. The new transformer has a rating of 14 MVA and will be tapped directly to the 230kV transmission system, providing capacity for new load growth as well as operational flexibility, ultimately improving system reliability.

Distribution automation program – Since 2016, JCP&L has implemented automatic load transfer schemes, or loop schemes, at many locations on its distribution system. Reclosers equipped with microprocessor-based controllers and supervisory communication and data acquisition ("SCADA") communications, which detect loss-of-supply conditions and automatically operate to allow power to be restored via an alternate circuit, have been installed. These schemes not only improve the reliability of JCP&L's distribution system, but they also provide real-time and historical telemetry to system operators and engineers, which assists in both day-to-day operations and longer-term planning. As of the end of 2019, JCP&L has 104 automatic distribution circuit tie schemes in place. Of these 104, 63 also have SCADA control. Plans for installing SCADA control on the remaining 41 circuit tie schemes that do not yet have SCADA control are in progress. Such circuit tie schemes automatically transfer customers to an adjacent circuit in the event of a circuit lockout, which helps to reduce the number of customers affected from a sustained outage. Each automatic circuit tie scheme typically involves two different circuits.

Q. What are JCP&L's major categories of capital expenditures during the Test Year?

A. JCP&L's capital expenditures can mainly be broken into six major categories:

<u>Reliability capital expenditures</u> - Work identified by JCP&L's Engineering Department to improve reliability in targeted areas of the system is included under this category. This includes adding sectionalizing devices such as reclosers, fuses, TripSavers, and switches as well as other miscellaneous equipment including lightning arrestors, animal guards, or spacer cable insulators. These installations improve the ability of the Company's electric distribution system to avoid outages and, when an outage occurs, to reduce the impact, and in some cases, the duration of outages. Examples of capital reliability projects include the construction of the now in-service major circuit tie for the Furnace Brook Substation, conversion of a significant section of a circuit served by McGuire Substation to open wire construction, and implementation of a loop scheme to improve reliability on a circuit served by the Cozy Lake Substation.

<u>Condition-based expenditures</u> - These include expenditures associated with engineering or construction field assessments, inspections and testing that indicates an increased potential for a premature or near-term equipment failure. Replacement (such as with respect to underground cable, substation breakers and poles) is then planned before the equipment becomes non-functional. Examples of capital projects in this category include the ongoing flood mitigation and remediation being performed at Sandy Hook Substation and the remediation associated with JCP&L's I&M programs.

Storm-related capital repairs and forced line and substation work - This category includes installation of new plant to resolve an equipment-related issue. Plant may include items like poles, transformers, switches and reclosers that are replaced on an emergency basis after being damaged during a storm or due to an incipient condition which requires immediate line or substation remediation at one or more of JCP&L's 339 substations. Examples of capital work in this category include the replacement of a failed substation transformer bank at Riverdale Substation, replacement of switchgear at Manitou Substation, and replacement of a circuit breaker at Rosemont substation.

New Capacity – Distribution Planning Engineers carefully analyze the distribution system to identify potential system overloads. These overloads may occur on the distribution feeder or at the distribution substation. This analysis includes identification of forecasted load growth and potential thermal overloads and proactive action is then taken to avoid unplanned outages. Planning Engineers identify low cost solutions such as load transfers to solve the problem. After low cost solutions have been exhausted, additional feasible solutions are evaluated to identify a cost-effective solution. This can include circuit re-conductoring, new feeders, or new distribution substations. One of the most significant capital projects related to new capacity is the ongoing addition of a new modular substation transformer bank and switchgear at Manchester Substation. This will provide additional capacity for the growth in Lakewood and the surrounding municipalities.

New business-related capital expenditures – New business expenditures include investments to connect new residential, commercial and industrial customers to the JCP&L distribution system and include significant investments related to upgrading existing service connections for increased load. Some examples of new business capital projects include the ongoing installation of the Rand Substation which is scheduled to be in-service this coming Summer and associated distribution equipment as well as the installation of a new circuit at Englishtown Substation.

Vegetation Management – This category includes continuing effort to widen its vegetation management right-of-way ("ROW") clearance corridors around conductors by removing overhanging vegetation, where possible.

V. INFRASTRUCTURE INVESTMENT PROGRAM

Q. Earlier, you mentioned that the Company has an IIP; can you further explain?

A. Yes. The Board approved a stipulation of settlement for an IIP in its Order dated May 8, 2019 in BPU Docket No. EO18070728 in the JCP&L Reliability Plus Proceeding, briefly mentioned above.

Q. Can you briefly describe the JCP&L Reliability Plus program as approved by the Board?

A. Yes. The JCP&L Reliability Plus consists of the capital investment of up to $97.01 million in the Company's electric distribution system beginning on June 1, 2019 and continuing through December 31, 2020.

Q. What projects are included in the JCP&L Reliability Plus program?

A. The IPP includes 10 incremental projects in three categories with capital investment levels as shown in Table 2 as follows:

Table 2

Overhead Circuit Reliability and Resiliency	Two projects	$55.13 million
Substation Reliability Enhancement	Four projects	$16.12 million
Distribution Automation	Four projects	$25.76 million
Total	Ten projects	$97.01 million

Q. Have you begun to implement the JCP&L Reliability Plus program and if so, can you describe some of the programs covered by the JCP&L Reliability Plus program?

A. Yes. As of November 30, 2019, JCP&L has completed the following work on the proposed JCP&L Reliability Plus projects, which I mention here to provide a useful perspective on the overall scope of operational reliability-related work underway at the Company in addition to the standard work described above.

- **Lateral Fuse Replacement with TripSaver II:** A total of 295 TripSaver II project components have been installed and placed in-service. TripSaver II reclosers, which are installed to reduce sustained outages on laterals due to temporary faults, as would occur if a tree limb or animal momentarily contacted a power line. For example, consider an instance where a tree limb impacts the distribution line during a windstorm. If the distribution line is currently protected by a fuse, the fuse will operate causing an extended outage until a crew is dispatched and is able to replace the fuse. Conversely, if the distribution line is protected by a recloser, the recloser is programmed to automate the reset process, restoring service after the limb falls through the distribution line and the temporary fault is cleared. Many faults on the system are temporary in nature, and in such cases, the replacement of fuses with reclosers will reduce what would have been extended outages to momentary interruptions. TripSaver II reclosers are designed to restore customers in less than 90 seconds following a temporary fault, avoiding an extended outage that would have occurred with a fused lateral. The number of TripSaver II project components to be installed as part of the JCP&L Reliability Plus program is 786.

- **Zone 2 Enhancement Vegetation Management:** Enhanced vegetation management has been completed within Zone 2 on 59 circuits. This Zone 2 Enhanced Vegetation Management involves the removal of overhang on selected circuits in the portion of the circuit from the first protective device to the end of the three-phase portion of the circuit, utilizing the same vegetation methods and practices that are currently used in Zone 1. This enhanced vegetation management will reduce the potential for tree damage and resulting outages and road closures during severe weather events. The total number of circuits to have Zone 2 Enhanced Vegetation Management completed as part of the JCP&L Reliability Plus is 222.

- **Substation Enhanced Flood Mitigation:** The Company installed permanent flood walls and automatic flood gates at one substation. In 2020, JCP&L will install enhanced flood mitigation at one additional substation for a total of two substations. This equipment will enhance protection against flooding and storm surges at substations that experienced flooding in prior storms. In addition, the permanent flood walls and automatic flood gates will eliminate the time-consuming, labor-intensive task of closing substation entrances with temporary barriers prior to forecasted storms. Further, four high-capacity pumps were ordered and received in December 2019 and are ready for use to mitigate water intrusion into substations when needed. Four additional high-capacity pumps will be delivered in June 2020.

- **Substation Equipment Replacement (Switchgear):** The Company has replaced substation switchgear with vacuum circuit breakers at one substation. State-of-the-art equipment and technology installed in a planned programmatic manner to will avoid expensive emergency replacements, which can result in prolonged outages, including where replacement parts for failed equipment are unavailable. In total, JCP&L will replace switchgear at four substations as part of the JCP&L Reliability Plus program.

- **Mobile Substation Purchase:** Mobile substations increase the capability of the Company to effect emergency restoration in the event of substation equipment failure. The mobile substation will also be utilized to assist in construction of some of the projects in JCP&L Reliability Plus. For example, when the Company replaces substation transformers, it will need to use a mobile substation to service load while the substation transformer is being replaced. The Company has finalized the design specifications and has placed its purchase order for one mobile substation to be delivered in 2020.

- **Modernized Protective Equipment:** The Company has installed and placed in-service twelve Modernize Protective Equipment project components. This project will enhance system reliability by installing new relaying equipment, reflecting currently available technology, that will provide increased monitoring and protection capabilities. In addition, these new microprocessor-based relays can remotely provide fault information, which can be used by engineering and operations personnel to locate the cause of an outage. The total number of Modernize Protective Equipment project components to be completed as part of the JCP&L Reliability Plus program is 56.

- **Install SCADA Line Devices:** JCP&L will replace existing hydraulic and electronic reclosers with Elastimold electronic reclosers with Schweitzer SEL-651 relays (or equivalent) and SCADA control. State-of-the-art reclosers and controls enable real-time monitoring of the recloser status and system conditions (voltage, current, etc.). Also, these improvements will allow for remote control to open and close reclosers to connect and disconnect certain portions of the grid, which increase safety and reliability and decreases operational costs. The project will also reduce the duration of many customer outages caused by temporary faults by replacing fuses with reclosers. JCP&L has installed and placed in service a total of 103 project components. The number of SCADA project components to be completed as part of the JCP&L Reliability Plus is 258.

- **Circuit Protection and Sectionalization:** In this project, JCP&L will replace three-phase fuses on 4.8kV delta circuits with Elastimold electronic reclosers with Schweitzer SEL-651 relays (or equivalent) and SCADA control. In addition to the previously-stated benefits of replacing fuses with reclosers and the advantages of

SCADA control and monitoring, replacing 4.8kV three-phase fuses also enhances safety for employees and the public by ensuring that all three phases open for permanent faults, reducing potential exposure to backfeed. A total of 30 project components were completed as of November 30, 2019. The number of Circuit Protection and Sectionalization project components to be completed as part of the JCP&L Reliability Plus is 69.

- **Distribution Automation (Loop Schemes):** The Company will construct distribution automatic loop schemes with Elastimold electronic reclosers with Schweitzer SEL-651 relays (or equivalent) and SCADA control for real-time system monitoring and remote control capability. A total of eight project components have been constructed and placed in-service. This project will target areas with critical customers. The project will also enable a customer on an enhanced loop scheme that experiences an outage to be automatically transferred to an adjacent circuit to restore service. The number of Distribution Automation Loop Scheme project components to be completed as part of the JCP&L Reliability Plus program is anticipated to remain at 17.

- **Remote Terminal Unit ("RTU") Upgrades:** This project will install load and voltage monitoring points to gather data via SCADA at the distribution level where no such points or limited points currently exist, upgrading existing RTU's in substations when necessary. Such RTU upgrades include replacing the RTU itself and may involve replacing copper-based communications using superior technology, such as fiber, cellular or radio. JCP&L expects to install a total of six RTU's as part of JCP&L Reliability Plus program.

Q. Does the Company seek to recover costs for the JCP&L Reliability Plus program in this proceeding?

A. Yes. Please refer to the testimony of JCP&L witnesses Mark A. Mader (Exhibit JC-3) and Carol A. Pittavino (Exhibit JC-4).

VI. OPERATIONS AND MAINTENANCE EXPENDITURES

Q. Please describe JCP&L's O&M activities.

A. JCP&L's O&M expenses include the day-to-day activities of operating and maintaining the electric system in accordance with the Company's plans and engineering practices. This work is primarily conducted in the field by the Operations Services, Operations Support and Regional Operations Support groups, with support from the

External Affairs group (mentioned in Mr. Fakult's testimony (Exhibit JC-2). Each year, JCP&L develops its O&M budget based on the estimated costs of its annual I&M programs, identified O&M projects and service restoration expenses. Generally, the starting point for the annual O&M budget is the prior year's budget with escalation adjustments that include, but are not limited to: gross wage increases for bargaining and non-bargaining employees; changes to headcount for expected staffing levels, attrition, internal transfers, Power Systems Institute ("PSI") hiring plans and engineers. Also included are any changes in accounting rules and/or practices and major training initiatives, such as the safety training started in 2019 on life-changing events and critical controls where DEKRA, a world-class leader in safety, was brought in to educate and provide field coaching to all levels of JCP&L employees. Finally, JCP&L also considers any new or changing technical or operational requirements or practices, including but not limited to the costs associated with complying with Board Orders or new regulations. This includes the Board's twelve storm-related recommendations associated with the March 2018 storms,[11] in addition to the 96 recommendations under which the Company operates from the Hurricane Irene and Sandy Board Orders, as well as the Board's Order following the Bow Echo storm in 2015.

Similar to the capital allocation process, the O&M expenses are prioritized to ensure funds are directed to projects with the greatest benefits. Analytical data is also evaluated to predict new business activities based on economic indicators. Year-over-year variations in O&M work plans must be clearly identified and reviewed during the budget review process. Planning for the upcoming budget year begins at the start of the calendar

[11] See, I*/M/O The Board's Review of Major Storm Events of March 2018*, BPU Docket No. EO18030255.

year and continues through June, and the budget is ultimately finalized and approved in the September – October timeframe.

Q. Please discuss JCP&L's Test Year O&M expenditure.

A. For the twelve months ending June 30, 2020, JCP&L's electric distribution O&M expenses are projected to be over $135 million (*see* Schedule DLP-1, which shows the Company's actual O&M spending on distribution operations for the six months ending December 2019 and the projected spending during the first six months of 2020 (ending June 30, 2020), which will be updated to actuals as the case proceeds). Of this total, the largest portion of O&M expense is attributable to the extensive I&M programs associated with JCP&L's lines and substations as described here below.

Q. Can you elaborate on the Company's I&M programs?

A. Yes. The largest single I&M program expenditure is the Company's vegetation management or tree trimming program. This field work is performed primarily by outside contractors in compliance with BPU regulations requiring that all circuits be inspected and, if necessary, trees trimmed at least once every four years. I will discuss this in more detail later herein.

Also included in the Company's I&M programs are the annual I&M of distribution line capacitors and distribution line reclosers. Overhead lines and equipment are visually inspected on a five-year cycle and an infrared inspection is performed on a four-year cycle. JCP&L also performs an underground safety and security assessment on its underground equipment on a five-year cycle. JCP&L currently employs a ten-year inspection program for all wood poles.

The I&M program for equipment inside the Company's substations, where a large number of customers could be impacted by a failure, are designed and executed to reduce unplanned equipment outages and include general substation inspections as well as equipment-specific I&M. Visual inspections of all substations are conducted on a monthly basis and are an important part of JCP&L's asset life-cycle management approach. The protective relay program consists of periodic testing, with prescribed periodicities or number of operations, depending on the type of relay scheme and voltage level.

The substation transformer I&M program, which includes visual inspections, utilizes a periodic diagnostic approach to evaluate the condition of each of the Company's substation power transformers. The tests conducted include dissolved gas analysis, Doble power factor testing, dielectric and physical oil testing, and transformer turns ratio, at prescribed periodicities. The infrared testing (or thermography) program is also an integral part of JCP&L's substation maintenance program. This testing is performed on an annual basis at all JCP&L substations.

The Company's battery maintenance program utilizes a monthly inspection of all substation batteries, which supply DC control power to substation electrical equipment. The batteries are cleaned as required. Impedance tests are also performed on the batteries on an annual basis. The circuit breaker program (which includes visual inspections) utilizes a periodic diagnostic program that utilizes various testing methods at various frequencies to determine the condition of a circuit breaker based on the circuit breaker's unique operating characteristics. The tests conducted include Doble power factor testing, oil dielectric strength, on-line timing, moisture, high potential and contact resistance testing at prescribed periodicities.

The JCP&L underground I&M program has been created for the maintenance of underground ducted systems. The program includes oil screen tests, dielectric tests, manhole inspections, vault inspections, and oil switch inspections performed at prescribed periodicities.

Q. Is the Company up-to-date on the performance of its I&M programs?

A. Yes. As shown in Tables 3-5, the Company has performed all of its required line-related I&M program requirements for 2019. This was also true for each of 2016, 2017 and 2018.

Table 3

JCP&L Northern Region 2019

Company-Wide Program	Equipment	Inspection Frequency	2019 Target (Number of Inspections)	Number of Inspections Completed	% of Target Completed
Distribution	Capacitor – Banks[(a)]	Annually	2,220	2,220	100%
	Recloser – Sites[(b)]	Annually	621	621	100%
Transmission	Aerial[(c)]	Twice / year	2	2	100%
Sub – Transmission	Ground Line Poles[(d)]	Ten-Year Cycle	2,183	2,183	100%
Substation	General	Monthly	1,788	1,788	100%
	Critical (NERC/RFC) Relay Schemes	Five-Year Cycle	170	170	100%
	Infrared Inspections	Annually	149	149	100%
	Battery	Annually	162	162	100%

Table 4

JCP&L Central Region 2019

Company-Wide Program	Equipment	Inspection Frequency	2019 Target (Number of Inspections)	Number of Inspections Completed	% of Target Completed
Distribution	Capacitor – Banks[(a)]	Annually	2,717	2,717	100%
	Recloser – Sites[(b)]	Annually	682	682	100%
Transmission	Aerial[(c)]	Twice / year	2	2	100%
Sub – Transmission	Ground Line Poles[(d)]	Ten-Year Cycle	2,543	2,543	100%
Substation	General	Monthly	2,123	2,123	100%
	Critical (NERC/RFC) Relay Schemes	Five-Year Cycle	200	200	100%
	Infrared Inspections	Annually	177	177	100%
	Battery	Annually	178	178	100%

Table 5

JCP&L Company-wide 2019

Company-Wide Program	Equipment	Inspection Frequency	2019 Target (Number of Inspections)	Number of Inspections Completed	% of Target Completed
Distribution	Capacitor – Banks[(a)]	Annually	4,937	4,937	100%
	Recloser – Sites[(b)]	Annually	1,303	1,303	100%
Transmission	Aerial[(c)]	Twice / year	2	2	100%
Sub – Transmission	Ground Line Poles[(d)]	Ten-Year Cycle	4,726	4,726	100%
Substation	General	Monthly	3,911	3,911	100%
	Critical (NERC/RFC) Relay Schemes	Five-Year Cycle	370	370	100%
	Infrared Inspections	Annually	326	326	100%
	Battery	Annually	340	340	100%

In addition, I also want to mention that the Company is up-to-date on all other I&M programs, which do not appear in the above charts. For instance, the inspection regimen for the Morristown underground network is tracked separately and has been entirely completed each year during the 2016-2019 period.

Q. Can you explain your reference to the Morristown underground network?

A. Yes. JCP&L operates a single underground secondary network in Morristown. A secondary network is a highly reliable distribution system operating at 600 volts and below. The network is designed and operated to provide continuous supply to distribution load within the network via a mesh configuration of primary and secondary lines. The networked system can withstand a loss a one or more lines or transformers within the network – referred to as a single or double contingency event – without interruption of load.

Under a Board Order dating back to 2012 (*I/M/O The Board's Investigation into Reliability Issues Related to JCP&L's Morristown Underground System* in BPU Docket No. E011090526, Order dated March 12, 2012) the Company has implemented a quarterly reporting process regarding the Morristown underground network inspection data, test procedures and improvement plans, as well as training and communications protocols with the municipal governing body.

The absence of major interruptions or failures within the network since 2012 confirms the network has been properly maintained using JCP&L's methods and procedures. In addition, the relationship with Morristown is exceptionally strong and cooperative.

Q. Please describe other programs that, in addition to the I&M programs, are included within JCP&L's distribution O&M expense?

A. In addition to the I&M programs discussed above, and the vegetation management programs discussed below, also included within distribution O&M expense are work activities including, but not limited to, operating the two Distribution Control Centers ("DCCs"), which are responsible for controlling day-to-day line and substation operations, as well as maintaining the fleet of JCP&L vehicles and facilities, storm restoration, routine repairs, troubleshooting, mark-outs of underground facilities, meter and streetlight repairs, connecting and disconnecting active and inactive customers, discontinuances and restorations of customers, joint use related work (*e.g.*, transfers/make-ready), responding to police/fire emergency calls and customer complaints, investigating and processing claims for and against the Company, and rubber glove purchases.

VII. VEGETATION MANAGEMENT PROGRAMS

Q. Can you discuss JCP&L's spending for its distribution vegetation management program during the Test Year?

A. Yes. Table 6 below provides the Company's actual spending on distribution vegetation management program mileage for six months ending December 2019 and the projected spending during the first six months of 2020, which will be updated to actuals as the case proceeds. These amounts are broken out from the amounts set forth in Schedule DLP-1 and do not include the expenditures under the JCP&L Reliability Plus program. Please note that these amounts also include non-programmatic vegetation management costs such as planned spot trimming, and other unplanned trimming as well as vegetation management work related to small storms but do not include any transmission-related vegetation management spending.

Table 6

Year	O&M	Capital	Total
July to December 2019	$9,299,706	$9,779,813	$19,079,519
January to June 2020	$7,890,712	$8,781,167	$16,671,879
Total	**$17,190,418**	**$18,560,980**	**$35,751,398**

Q. Can you provide more details regarding the JCP&L distribution vegetation management program?

A. Yes. In general, the JCP&L distribution vegetation management program is designed to assist JCP&L in meeting its obligations to provide safe and reliable service to its customers through the use of effective vegetation management techniques that assist in the efficient and reliable operation of JCP&L's electric distribution system.

Vegetation along JCP&L's electric distribution circuits is inspected on a four-year cycle and, if necessary, such vegetation is removed, pruned or otherwise controlled. In addition, on a spot basis outside of the regular four-year cycle, the Company inspects and trims vegetation, as necessary or required as a result of the findings of various other Company maintenance programs such as thermography inspections, overhead line inspections, and the customers experiencing multiple interruptions ("CEMI") program. This allows JCP&L to address specific circuit and substation reliability issues or concerns, including for purposes of maintaining access, making repairs, restoring service and protecting the safety of the general public. Many states, including New Jersey, and utilities have adopted a four-year trimming periodicity, which strikes a balance between cost and reliability benefit.

Q. Please describe the standards applicable to the JCP&L distribution vegetation management program.

A. JCP&L's distribution vegetation management program is subject to, and complies with, the Board's requirements as set forth in the New Jersey Administrative Code ("N.J.A.C.") at N.J.A.C.14:5-9.1 through 5.9.10, entitled "Electric Utility Line Vegetation Management" (the "Board's VM Regulations"), as these regulations were amended effective August 15, 2015. In addition, consistent with the Board's VM Regulations at N.J.A.C.14:5-9.5, all vegetation clearing work is performed in compliance with ANSI Z133.1 and A-300 standards, as well as all applicable OSHA requirements.

Under this framework, the degree and type of vegetation clearance required for electric distribution lines to function effectively is dependent on: the voltage and height of the conductor; the type of tree, its growth rate and branching habit; the extent of, or potential for, vegetation to interfere with energized conductors; and the importance of the affected facilities in maintaining safe and reliable service.

Q. How is the Company's vegetation management work performed and administered?

A. The JCP&L Forestry department (comprised primarily of a manager, supervisor, and forestry specialists) utilizes external vegetation management contractors to perform this work. The completed trimming is inspected by JCP&L forestry specialists to ensure that the contracted quality standards and specifications are met.

Although the number of contract employees varies during the course of a year, at any given time there can be in excess of 450 contract and JCP&L employees conducting the JCP&L distribution vegetation management program.

Q. Please describe the mileage dimensions of the JCP&L electric distribution system.

A. In total, the JCP&L Forestry department maintains approximately 13,825 circuit miles of distribution circuits (including the "wye-configured" 34.5 kV facilities) as part of its distribution vegetation management program. On a pro-rata basis approximately one-quarter of this distribution mileage is addressed annually under the cyclical JCP&L distribution vegetation management program. In addition, spot trimming to address reliability and safety concerns or issues takes place as needed.

Q. Are the same number of miles subjected to vegetation management every year?

A. The annual circuit mileage varies due to such factors as circuit configurations and the geographic and municipal aspects of the circuits designated for vegetation management in any given year. These mileage allocations are reviewed periodically to further consider circuit and substation changes. Table 7 below illustrates the most recent information regarding the mileage to be trimmed for the JCP&L distribution lines during a specific year of a four-year cycle.

Table 7

Description	4 Year Cycle 2016/2020	4 Year Cycle 2017/2021	4 Year Cycle 2018/2022	4 Year Cycle 2019/2023	Total (circuit miles)	Average (circuit miles)
Distribution & Subtransmission	3,373	3,607	3,449	3,396	13,825	3,456

Q. Please describe JCP&L's service territory in terms of tree density.

A. As discussed earlier in my testimony, the entire JCP&L service territory is generally wooded and the northwestern part of the territory, located within the Northern Region, is one of the most heavily forested area in New Jersey, as depicted in Figures 1 and 2, above. Indeed, in the context of a recent storm experience and vegetation management, Board President Fiordaliso acknowledged the rural and heavily treed character of the JCP&L Service territory when (in what I assume was a reference to the Company's IIP vegetation management expenditures) he said:

> As you know, JCP&L has the territory that is rural, has a lot of trees, and so on. And they've given us a commitment that they are going to be spending considerably more money on vegetation management. And this [is] a priority as far as their territory is concerned.

(BPU Agenda Meeting, December 6, 2019 Tr. at pp.4-5)

Q. Is the Company following the Board's regulations in the conduct of its vegetation management program?

A. Yes. JCP&L's maintenance cycles are up-to-date and were completed annually on a timely basis for the period 2016-2019. I would like to add that, since January 1, 2016 and continuing through December 31, 2019, JCP&L continued removal of overhanging vegetation clearing requirement on the feeder main line from the breaker up to the first protective device (Zone 1 or Lock-Out Zone). Prior to that, beginning in approximately 2012, the Company started its own independent focus on Zone 1 vegetation, which was discussed in prior 2012 and 2016 rate cases. In 2015, the Board issued regulations requiring the current program (beginning in January 2016). See, N.J.A.C. 14:5-9.8 (b). In my experience, the number of tree-related interruptions resulting from feeder breaker lock-outs represents a substantial portion of the total tree-related outages, which provides support for the wisdom of the Board's regulations requiring the programmatic approach to Zone 1.

Q. Are there other aspects of the vegetation management program that you can describe?

A. Yes. I think it is worth mentioning that non-storm, tree-related outages that impact 500 or more customers or are greater than three hours in duration are required to be investigated by a Company forester, tracked by the Company and reported in the Company's Annual System Performance Report. The Company has fully complied with this requirement and the results of these investigations have been informative. For instance, Table 8 below, provides a summary of data from such investigations from the period 2016-2019:

Table 8

Year	# of Investigations	On ROW	Off ROW	Secondary Services	≥500 Customers %	≤500 Customers %; > 3 hrs.	< 10 Customers and > 3 hrs.
2016	1,089	13%	70%	16%	4%	96%	57%
2017	1,702	13%	71%	16%	7%	93%	61%
2018	1,789	15%	69%	16%	5%	95%	61%
2019[12]	1,470	11%	66%	24%	6%	94%	56%

This data provides a perspective, which I will describe more fully below, on the numbers and sources of tree-related incidents and their impact on reliability as well as a perspective on the Company's ability to prevent them.

Q. Would you describe the perspective this table provides regarding the sources of the outages?

A. Yes. Given the heavily forested character of the JCP&L service territory it may not be surprising, but this data confirms that off ROW trees continue to be a primary driver of the number of tree-related outages and the impact on reliability. When combined with outages caused by a tree falling on secondary wires, which impact a single customer (and are typically and mainly outside the ROW, and are the customer's responsibility, when they detach from the customer's premises, to have reattached), nearly 85% of the tree-related

[12] The Company's review of the 2019 year-end data is in progress and is approximately 80% complete; accordingly, although subject to change as of the date of this testimony, I think the reported amounts are directionally representative even if not final.

outages are unrelated to areas within the scope of the Company's control or responsibility relative to its vegetation management programs. A little further perspective regarding the sensitivities of customers and property owners regarding trees may be gleaned from the fact that even in the aftermath of Hurricane Sandy in 2012, property owners still continue to refuse the Company permission to remove hazard trees, which are structurally unsound trees on (assuming that the Company doesn't have specified legal rights otherwise, which is often the case) or off the ROW that could strike electric supply lines when they fail.

In 2019, the Company was denied permission to remove (in non-storm situations) on approximately 70 occasions (approximately 60 of which related to refusals to allow removal of ash trees). The Company was denied permission in 2018 on 9 occasions, in 2017 on 17 occasions, and in 2016 on 2 occasions. Although the Emerald Ash Borer ("EAB"), discussed below, appears to account for the much higher 2019 results as compared to prior years, the 2019 experience demonstrates the reluctance of property owners (where property owner permission is required) to allow for the removal of trees that threaten the distribution system.

Moreover, these statistics do not reflect the Company's anecdotal experience in storm situations where requests for permission to remove are more frequent and where refusals of removal are very prevalent. This prevailing attitude means that the Company is often left with only the ability to trim where it would be better from a reliability perspective to remove the tree and where both situations (*i.e.*, trimming and/or removal) may be subject to permission from the property owner.

Q. Do you have any observations to add regarding the Company's experience relative to vegetation management within its service territory?

A. Yes, I do. I have observed that, as a result of the Company's Zone 1 initiative, outages caused by trees on ROW and limb fall-ins from trees off ROW (as opposed to fallen off ROW trees themselves) have trended downward since 2014, as indicated in the table below.

Table 9[13]

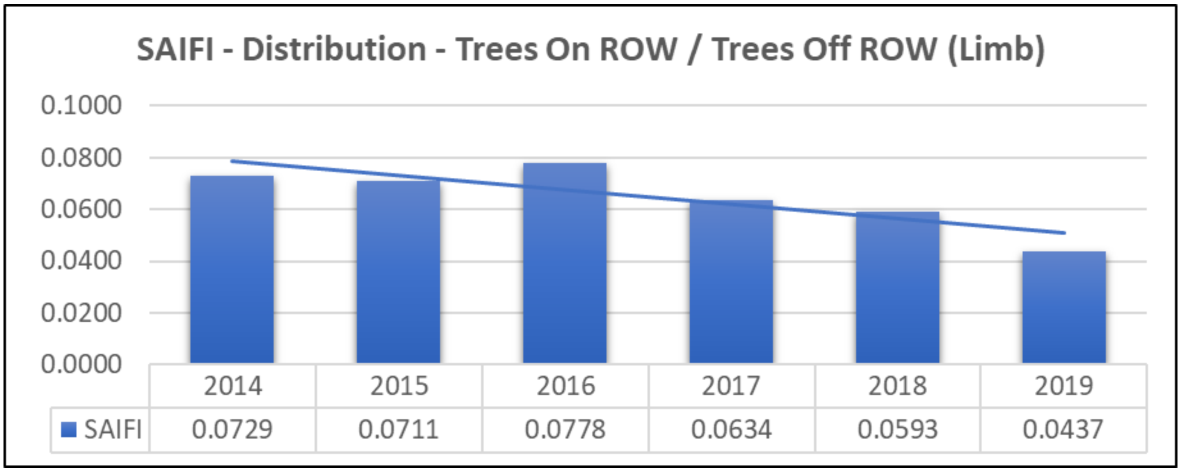
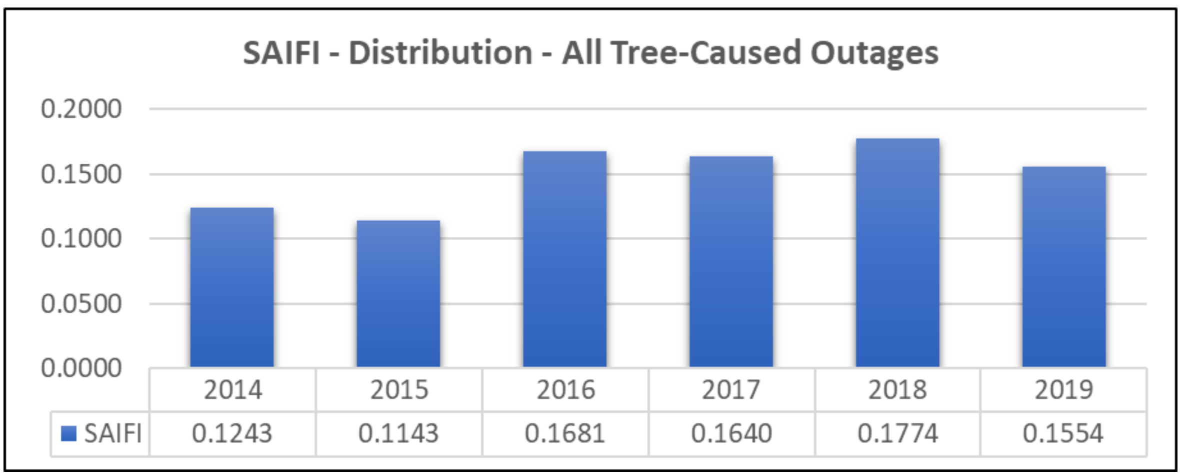


Table 10



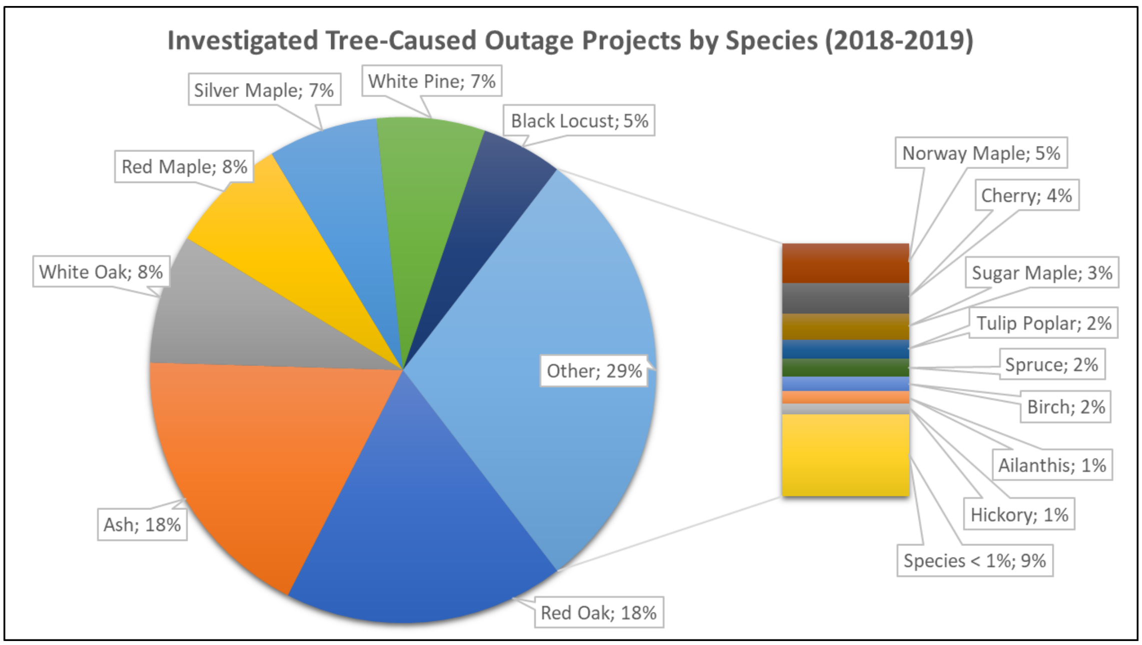
[13] I note that this chart introduces the term "SAIFI" for the first time in this testimony. SAIFI stands for System Average Interruption Frequency Index. SAIFI represents the average frequency of sustained (greater than five minutes in duration) interruptions per customer during the reporting period and is calculated as follows:

> **SAIFI** = total number of sustained customer interruptions per reporting period /
> total number of customers served per reporting period.

It should be noted that, while the overall trend for all tree-caused outages is unfavorable (as reflected in the SAIFI impact shown in Table 10 above), this can largely be attributed to decimation of off ROW ash trees as a result of the EAB, described below.

In fact, as shown in Table 11 below, ash trees are now tied for first as the leading cause of outages when ranked by species – causing 18% of investigated tree-related outages in the 2018-19 time period.

Table 11



Q. Please describe the EAB and its impacts.

A. The EAB is an invasive wood boring beetle, native to eastern Asia, that is highly destructive to the ash species. The larvae (the immature stage) feed on the inner bark of ash trees, disrupting the tree's ability to transport water and nutrients. Due to the lack of water transportation, EAB infested ash trees dry out rapidly, becoming brittle, and susceptible to failure. Once infected, it is just a matter of time before the ash tree will die. The EAB has been moving west to east, beginning in Michigan in the early 2000's, and was first identified in JCP&L's service territory in 2017.

Thousands of ash trees now pose a threat to JCP&L's facilities, causing outages that lead to decreasing reliability and increasing hazards for not only forestry workers but also line workers. According to the Davey Resource Group[14] the shear strength of ash wood undergoes a five-fold decrease after the tree is infested by the EAB. This increases the danger of simply working near ash trees.

Q. Has the Company undertaken additional distribution vegetation management efforts in order to support enhanced system reliability?

A. Yes. Beginning in 2018, the Company began allocating capital dollars to mitigate against the EAB by targeting removal of ash trees located within zones one and two. In 2018, this allocation was $4.6 million. In 2019 it was $6.0 million. In the Test Year, the allocation amounts to $5.6 million.

Q. What has been the result of this effort?

A. As shown on the following table, the evidence clearly recommends the continuation of efforts to target the ash tree. The Company's anecdotal experience is that EAB infiltration has increased and the Company's targeting efforts have likely prevented the impact on tree-related outages from being far worse.

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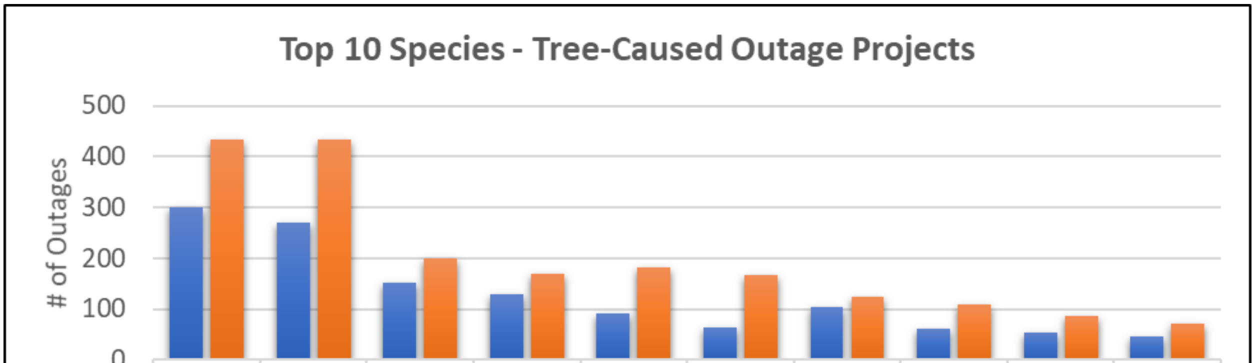
[14] As cited in: Invasive borer quickly turns ash trees into widowmakers, Paul Hetzler, October 22, 2017. Available at: https://blogs.northcountrypublicradio.org/allin/2017/10/22/invasive-borer-quickly-turns-ash-trees-into-widowmakers/

Table 12



	Red Oak	Ash	White Oak	Silver Maple	Red Maple	White Pine	Black Locust	Norway Maple	Cherry	Sugar Maple
2018	301	270	153	128	92	65	105	61	55	47
2019	433	433	199	169	183	167	125	109	86	72

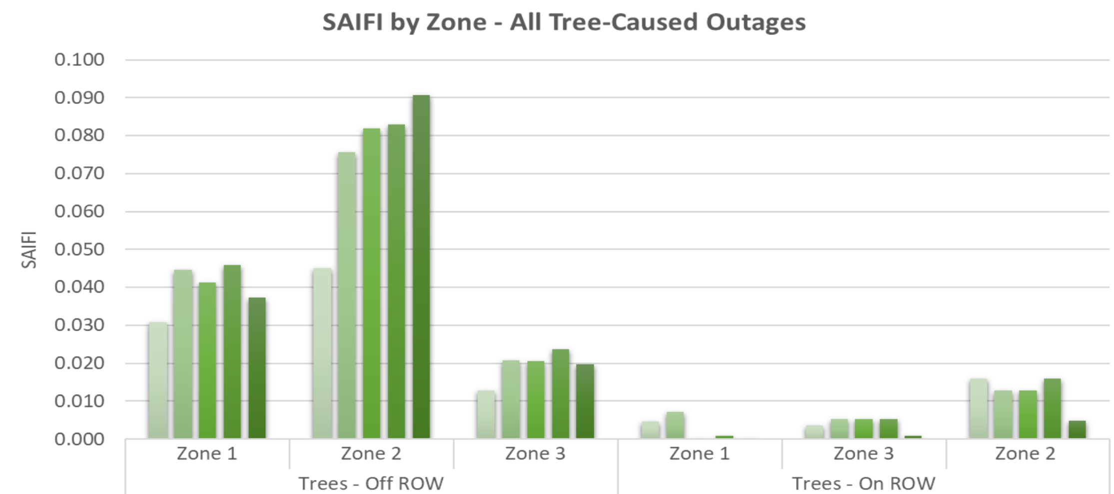
Q. Will work targeting removal of ash trees continue in 2020?

A. Yes. As part of JCP&L's four-year cycle, the Company will continue to target ash trees located within zones one and two, prioritizing those circuits that are performing poorer first in a cycle year and moving thereafter to the better performing circuits.

Q. Is there any other aspect of the Company's vegetation management program that you would like to discuss?

A. Yes. Earlier I made reference to vegetation management activities in both Zone 1 and Zone 2. I would like to revisit that briefly. As I explained, programmatically, from 2016 through 2019, JCP&L has completed conductor-to-sky overhang removal in Zone 1 (the circuit lockout zone) on all its distribution circuits. The Company believes that the benefits of that concerted effort are beginning to be evidenced statistically indicating that it has been a wise and effective approach for the Company to undertake (consistent also with the Board's regulations adopted in 2015). As displayed in the following table, the Company has seen a marked decrease in the SAIFI impact to customers from outages caused by tree-related outages in Zone 1 as compared to increased SAIFI impact to customers affected by tree-related outages in Zone 2 over the period 2016-2019.

Table 13



	Trees - Off ROW			Trees - On ROW		
	Zone 1	Zone 2	Zone 3	Zone 1	Zone 3	Zone 2
2015	0.031	0.045	0.013	0.005	0.004	0.016
2016	0.045	0.076	0.021	0.007	0.005	0.013
2017	0.041	0.082	0.021	0.000	0.005	0.013
2018	0.046	0.083	0.024	0.001	0.005	0.016
2019	0.037	0.091	0.020	0.000	0.001	0.005

This data gives us good reason to think that, over time, the similar additional focus on removal of overhanging vegetation clearance being given to Zone 2 through the Zone 2 Enhancement Vegetation Management component of the JCP&L Reliability Plus program (discussed above), will yield fruitful results relative to an improved customer reliability experience.

Q. Do you have any concluding remarks regarding the Company's vegetation management?

A. Although I will make reference to this discussion in later sections of this testimony, I can confidently say that that the Company has a very robust and forward-thinking vegetation management program that complies with or exceeds regulatory requirements. Consistent with President Fiordaliso's remarks this past December, the Company continues to focus on the unique heavily-forested and rural character of its service territory with a strong and demonstrable commitment to managing vegetation (within its rights to do so) in order to provide safe and reliable service.

I also believe that the Board was wise to drive for increased statistical data gathering and analysis (in the amendments to its regulations as adopted in 2015), which appear to be demonstrating an increasing impact of off ROW trees on reliability. Coupled with an appreciation of the limited rights that utilities, generally, and JCP&L, in particular, have to deal with such matters, the data gathering process will, hopefully, lead to the development of additional legislative or regulatory tools to assist in addressing such issues. In the meantime, the Company will continue to meet its commitments to attempt to reduce the impacts of vegetation within its densely forested service territory on the electric service experience of its customers. In turn, the Company requires full and timely recovery of its vegetation management program costs, as discussed by Mr. Mader and Ms. Pittavino in their direct testimony.

VIII. <u>STORM RESPONSE PROCESS</u>

Q. How does the Company address storms and emergency conditions impacting the electric system and its customers?

A. In response to such occurrences, JCP&L implements its very robust and comprehensive Emergency Plan for Service Restoration ("E-Plan") for storm response and management.

Q. Can you summarize and explain the E-Plan?

A. Yes. JCP&L utilizes the Incident Command System ("ICS") in its emergency response organization, adhering to the principles and high-level structures of the National Incident

Management System ("NIMS") framework as appropriately applied in an electric utility environment.

JCP&L's storm and emergency management process is characterized by detailed planning, regular training, internal communications, the utilization of affiliated and non-affiliated mutual assistance personnel to assist in response and restoration activities, information technology support, and internal and external stakeholder communication. The Company's E-Plan contains the storm and emergency planning and response activities which are used to conduct storm and emergency preparedness, response, and service restoration using the principles and structures of the ICS as the framework for these elements of JCP&L's storm and emergency response plan, in each instance, under the leadership of the designated Incident Commander.

The strategic objectives of the E-Plan are: (i) Emergency Response Organizational Awareness; (ii) Organizational Readiness; (iii) Effective Planning; (iv) Effective Mobilization & Logistics; (v) Effective Hazard Identification; (vi) Effective Hazard Assessment; (vii) Effective Restoration Management; (viii) Continuous Improvement; and (ix) Effective Communications.

Among other things, the Manager of Emergency Preparedness is responsible for creating and implementing a unified and cohesive storm and emergency response posture within JCP&L by partnering and consulting with JCP&L leadership and employees who are responsible for emergency planning and preparedness communications, training and operations. The position coordinates and maintains operational information and represents JCP&L's emergency operational status to the media, government, regulators, emergency management agencies, company executives and internal organizations. The Manager of Emergency Preparedness is also accountable to establish business relationships with internal/external customers, agencies, community emergency organizations, and public safety organizations consistent with carrying out the responsibilities of the position.

Q. Does the Company have an outage management system ("OMS")?

A. Yes. The Company uses the PowerOn OMS for outage management. The PowerOn OMS is an integral tool in the storm recovery and restoration process. Indeed, all FirstEnergy utilities utilize the same outage management system in concert with the E-Plan. This consistency of technology and process facilitates the use of additional DCC dispatchers from throughout the FirstEnergy footprint in the affected areas to provide assistance. It also allows for support efforts to be conducted from remote locations. I should add that FirstEnergy is also undertaking a corporate-wide initiative to replace the current OMS used by each of its ten electric distribution companies, including JCP&L. The OMS replacement is part of an overall Advanced Distribution Management System ("ADMS")[15] implementation and is projected to be operational for JCP&L by mid-2022.

Q. Is there a meteorological component to the E-Plan process?

A. Yes. Forecasting and timely response to forecasting data for purpose of planning, mobilization and overall readiness is extremely important to the E-Plan process and the triggering of the ICS structure. In this regard, not only does FirstEnergy rely on standard external resources for forecasts, it has also made a significant investment in developing its own internal forecasting capabilities by creating, staffing and operating an internal meteorological support function.

[15] An ADMS is a software platform that supports the full suite of distribution grid management and optimization. An ADMS includes functions that facilitate outage restoration and optimize the performance of the distribution grid.

This is a decision-based support service addressing the specific weather concerns of FirstEnergy. Because information from routine intelligence streams (*e.g.*, National Weather Service, The Weather Channel) does not necessarily or always address Company-specific weather concerns, the internal meteorological support provides FirstEnergy a value-added service in order to maintain a continuous and knowledgeable understanding of impending weather events.

The support service consists primarily of real-time monitoring, forecasting, and post-event analysis products for weather phenomenon of concern to FirstEnergy. Information is conveyed to weather-sensitive FirstEnergy business units and personnel through a blend of automated and manual methods including web-based notifications, email, text messages, and pager. Participation in storm conference calls occurs on an as-needed basis before and during significant weather events.

Q. Does the Company conduct training with respect to its E-Plan?

A. Yes, regularly. Among the many individual and group or functional training opportunities, the Company conducts an annual exercise, which incorporates ICS principles and promotes an enhanced understanding of ICS roles and responsibilities. This exercise is conducted each year with advance notice to Board Staff (and an invitation to attend and participate). Records of training are maintained in a Company database designed for such purposes.

Q. Does JCP&L participate in any mutual assistance organizations related to storm response?

A. Yes. JCP&L participates in the Regional Mutual Assistance Groups ("RMAG"), the Great Lakes Mutual Assistance ("GLMA"), the Southeastern Electric Exchange ("SEE") and the North Atlantic Mutual Assistance Group ("NAMAG"). JCP&L also participates in the New Jersey Consortium of Electric Companies ("NJC") which is a group of New Jersey electric distribution companies, municipal utilities, and cooperative utilities working to effectively and collaboratively share electric restoration resources when needed to respond to major outages within New Jersey. In addition, as a member of the Edison Electric Institute ("EEI"), JCP&L has access to operating personnel from utilities and contractors throughout the United States and Canada. In a large-scale event where many Companies are requesting mutual assistance, the EEI's National Response Event process can be activated by utilities when multiple RMAGs cannot adequately support the resource requirements of the requesting utilities. The Company also works directly with non-RMAG companies and contractors to secure resources when needed. In addition, as mentioned earlier, operating personnel from the other FirstEnergy utilities are available and willing to travel to New Jersey to assist in any emergency and storm restoration activities. DCCs throughout the FirstEnergy system coordinate all restoration activities and use the same FirstEnergy Manual of Operations for programmatic implementation. Training is provided annually to ensure compliance with programmatic and regulatory requirements.

Q. Does the Company's E-Plan comply with Board regulations and/or applicable orders?

A. Yes. The E-Plan has been designed to comply with all applicable rules and Board directives as well as applicable industry standards, and the Company is in compliance with all Board Orders, directives and regulations pertaining to such matters. Indeed, the E-Plan is utilized across the FirstEnergy utility system and is regarded internally and externally as a very robust approach to storm responses and restoration. For instance, EEI presents awards twice annually to member companies to recognize extraordinary efforts to restore power or for assisting other electric companies after service disruptions caused by weather conditions and other natural events.

During the period of 2016 through 2019, FirstEnergy was awarded the Emergency Recovery Award a total of seven times by the EEI. Further, during the same period, EEI also awarded FirstEnergy the Emergency Assistance Award a total of five times. In my estimation, these awards are well-deserved based upon the ongoing effective implementation of the well-designed E-Plan through the ICS structure, which has visible Company leadership support and endorsement and provides a resilient and scalable response framework that promotes stakeholder involvement in a comprehensive all-hazards approach to planning, preparedness, response, and restoration activities.

Q. How do the Board's Orders impact the Company's storm process that you have been describing?

A. First, let me say that I see the Board's various storm orders as showing an evolving understanding based on the lessons-learned from the New Jersey utilities' storm-related experience. Indeed, I think of the Board's review and Orders as a very formal lessons-learned process conducted in the regulatory forum. More specifically, the Board's storm orders have prompted or required changes, additions, adjustments and the use of new technologies or the application of existing technologies in new ways. In some cases, the Board's storm orders are the drivers of significant and substantial changes in how the Company and other EDCs design and implement their storm recovery and restoration processes as well as how they communicate it to their customers, including interactively on the web, and how they otherwise communicate it to public officials, in real-time. For instance, as I mentioned earlier, since 2013, in addition to the approximately 96 recommendations from the Hurricane Irene and Sandy Board Orders, and as well as the

Board's Order following the Bow Echo storm in 2015, the Board has required the Company or the Company and the other EDCs to comply with and to develop approaches to accomplishing twelve storm-related recommendations associated with the March 2018 storms. Logic tells us that just by virtue of the extensive number of requirements in recent years there are significant costs associated with development, implementation and continuing compliance with these orders that required changes to existing methodologies or the imposition of new requirements on an ongoing basis, many of which are very difficult to isolate, identify and quantify.

Q. Is the E-Plan fully implemented in response to each forecasted storm?

A. Yes. However, I should add that, by "fully" I mean to the extent indicated by the ICS planning and assessment for any particular storm, which is an iterative and data-driven process. In this regard, it may be helpful for me to describe in more detail the Company's experience and response with the major storm events of 2018 and 2019, which I do below.

Q. Before turning to the details of some of the major storm events of 2018 and 2019, and related to your referring to the ICS planning and assessment as an iterative process, are there occasions when pre-storm planning, marshalling of resources and even staging is undertaken but later not utilized or fully utilized?

A. Yes. As mentioned earlier, JCP&L relies on weather forecasts to start planning and assessing. As is commonly known, weather forecasts are very dynamic and fluid. They are subject to constant change. However, the element of timing and mobilization combined with the severity of the forecasted storm can require extensive and costly implementation actions in order to be properly prepared. A good example of this was the Company's experience with Tropical Storm/Hurricane Hermine in late August and early September 2016.

Q. Please explain.

A. Beginning Sunday, August 21, FirstEnergy meteorologists tracked potential tropical disturbances in the Atlantic Ocean. First, initial forecasts for this tropical event, later named Hurricane Hermine, initially indicated a threat to Florida. However, those initial forecasts changed and the tropical disturbance proceeded south of Florida Power & Light territory.

Next, Hurricane Hermine reformed in the Gulf of Mexico and FirstEnergy meteorologists continued to advise the Company to take a "cautiously watching" approach given the continued uncertainty in the weather models' forecast for the next 96-hour timeframe. Given the uncertainty of Hurricane Hermine's track, and, in preparation for a potential outage event, a storm conference call was held on Thursday, September 1 to obtain a status on all storm preparations.

The FirstEnergy meteorologists continued to monitor Hurricane Hermine and communicated the potential for a tropical event on the Eastern seaboard for Labor Day weekend. At 10:38 a.m. on September 1, the FirstEnergy meteorologists issued an advisory of a tropical event off the New Jersey coast. The Company's Outage Volume Model ("OVM") showed the potential for outages approaching the 600,000 customer-range. At this time, JCP&L intensified its storm preparations to a Level IV event and requested mutual assistance. JCP&L activated its flood mitigation plan and deployed elements of its back-up communications plan in preparation for the event. JCP&L mobilized line, forestry, staging site contractors, and arranged to move and moved corporate and affiliated FirstEnergy utilities' personnel to New Jersey on Friday, September 2 and Saturday, September 3 in preparation for a potentially devastating storm.

Indeed, then New Jersey Governor Christie issued Executive Order No. 204 on Saturday, September 3 declaring a State of Emergency for three New Jersey counties: Atlantic, Cape May and Ocean.

From there, Hurricane Hermine's path changed, and the impact time was changed to Sunday, September 4 at mid-afternoon for JCP&L's Central Region. In preparation, JCP&L opened its Emergency Command Center at 7:00 a.m. on Sunday, September 4. As Hurricane Hermine's path continued to turn further east, the impact to JCP&L was reduced. Ultimately, JCP&L released all remaining personnel and resumed normal operations at 9:30 a.m. on Monday, September 5.

I use this as an example of the extensive preparations and mobilization efforts that can be necessitated by reliable weather forecasts regarding acts of nature that are not subject to human control. With the benefit of hindsight and the opportunity to second-guess even before the coast was clear, the Governor's office was criticized for issuing the state of emergency order for the Labor Day holiday weekend, prompting the Governor to describe the situation in terms of being "damned if you do, and damned if you don't" and emphasizing that the Labor Day weekend population at the New Jersey shore swells by 900,000, creating a very serious potential public-safety concern.[16]

Objectively, good utility practice, and compliance with applicable Board Orders as well as, when applicable, the implications of a declared state of emergency, in the face of forecasted weather and other emergency events, have required, and will continue to require, extensive preparations and mobilization efforts and costs in order to assure that recovery

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[16] Philadelphia Inquirer, September 4, 2016.
Available at: https://www.inquirer.com/philly/news/new_jersey/20160905_Far-off_Hermine__near_hurricane_strength__ruins_Shore_s_Labor_Day_weekend.html

and restoration resources are positioned safely and ready for deployment when the dangerous weather has departed the area. To do so was, is, and will continue to be prudent, even if the predicted storm does not materialize as forecast.

Q. Can you provide a more recent example?

A. Yes. On Saturday, January 19, 2019, New Jersey Governor Murphy issued Executive Order No. 50 declaring a State of Emergency. According to the Executive Order, the National Weather Service forecasted that a major winter storm would impact New Jersey beginning on January 19, 2019, causing hazardous weather, including more than a foot of heavy, wet snow to parts of New Jersey, sleet, heavy and freezing rain, ice, bitter cold, sustained high winds, tidal and coastal flooding and main stream and river flooding. The National Weather Service issued storm warnings for a substantial portion of New Jersey, including a winter storm warning for the northern portion of New Jersey, and a winter storm watch throughout central New Jersey. Based on the weather forecast and similar past events, JCP&L's OVM predicted that JCP&L would experience over 100,000 customer interruptions. In advance of the storm, JCP&L secured 600 line contractors, 200 forestry contractors, 200 hazard responders and 130 damage assessors to assist with restoration efforts. Most of the line contractors came from Michigan; however, some arrived from as far away as Alabama, Florida, Illinois, Kentucky, New York, Ohio and Tennessee. JCP&L also opened a staging site at the Livingston Mall to quickly process, house and feed the expected contractors and to stage materials. Despite the weather forecast and the outage volume model prediction, JCP&L experience a relatively low number of customers (approximately 28,000) affected by this weather event.

IX. <u>2018 AND 2019 MAJOR STORM RECOVERY & RESTORATIONS</u>

Q. Can you discuss additional and more recent examples of the implementation of the Company's storm recovery and restoration processes?

A. Yes. I think several examples from the last two years (2018-2019) will help to further understand the extensive efforts undertaken to respond to major storms implementing the E-Plan using the ICS structure and an opportunity to demonstrate how JCP&L has prudently incurred the costs that were necessary in planning for, responding to, and replacing facilities and equipment damaged as a result of such storms and making permanent repairs. As I have discussed, the Company has properly utilized its robust E-Plan and ICS structure to address these major storms, meeting applicable industry and regulatory standards.

Q. Please describe the impact of Winter Storms Riley and Quinn ("Riley/Quinn") on the Company's system.

A. On March 2, 2018, Winter Storm Riley resulted in over 16 inches of wet snow in JCP&L's Northern Region and seven inches in JCP&L's Central Region. Accompanying the wet snow, JCP&L experienced wind gusts of more than 70 miles per hour ("mph"). This combination of devastating wind and heavy wet snow caused many trees and limbs to break causing tremendous damage to JCP&L's distribution system.

As JCP&L was engaged in the restoration efforts from Winter Storm Riley, a second winter storm, Quinn, moved into the service territory the morning of March 7, 2018. Winter Storm Quinn brought more high winds and additional wet, heavy snow. The Northern Region received up to an additional 13 inches and the Central Region received more than an additional 7 inches of snow. In addition, the Northern Region experienced wind gusts of up to 30 mph, and the Central Region of up to 40 mph. Riley/Quinn caused power outages that affected more than 526,000 of JCP&L's 1.1 million customers.

Q. Please describe the damage experienced during Riley/Quinn.

A. The damage resulting from trees was extensive. The high winds and snow load on trees brought limbs outside the overhead clearance onto the conductor, tripping breakers and taking down conductors. Also, healthy trees located outside the ROW fell into the conductors. The volume of street side trees also caused numerous road closures delaying and impacting JCP&L's response. The combination of Riley/Quinn caused damage to 2,507 crossarms, 805 poles, 517 transformers and nearly 363,000 feet of conductor. Through the hazard response process, JCP&L addressed approximately 19,000 trouble orders.

Q. Did JCP&L experience any complications during restoration efforts in regard to Riley/Quinn?

A. Yes, very much so. Electric utilities, including JCP&L, are dependent upon meteorological forecasts to determine potential outage impact and need for additional resources, both people and equipment. Decisions are made based on the information available. Planning becomes very difficult when weather forecasts change due to fast changing weather conditions, which in turn, change projected impact hours in advance of or even during an event, which is what JCP&L experienced in this event.

Regarding Winter Storm Riley, meteorological forecasts, two days in advance predicted the potential for high wind gusts in portions of New Jersey but did not forecast snow. One day in advance of Winter Storm Riley, meteorologists continued to predict high wind gusts but expanded the forecast to include snow in the northern-most portion of JCP&L.

Although participating in RMAG calls early on, JCP&L was confident it could adequately handle restoration with internal resources based on the current forecasts and did not request any additional resources. Early on March 2, Winter Storm Riley began impacting JCP&L. As the event progressed, forecasts were revised to include large amounts of snow across most of JCP&L's service territory. Because of the increase in the severity of the event, JCP&L immediately requested additional line workers to support restoration efforts. It was difficult early on to obtain additional resources as resources were unavailable through mutual assistance partners due to the wide geographic area impacted by the weather.

JCP&L was ultimately able to acquire more than 3,100 line workers, in addition to 360 JCP&L line workers, through contractor relationships and FirstEnergy affiliated resources. In total, approximately 7,000 FTEs worked to restore service to JCP&L's customers during Riley/Quinn.

Q. Were there other complications during restoration efforts in regard to Riley/Quinn?

A. Yes. Restoration efforts were hampered throughout the event due to the extensive damage from and during Winter Storm Riley in the form of trees, poles and wires. Deep snow, closing state, local, county roads and blocking access to locations, together with hazardous road conditions also made travel very difficult. Continuous high winds halted restoration activities across the entire JCP&L service territory for 11 hours beginning at 9:00 p.m. on March 2 as winds increased to over 40 mph, exceeding the threshold for bucket trucks to safety operate in the air.

Despite these challenges, by the end of day March 6, fewer than 25,000 customers impacted by Winter Storm Riley remained out of service. Beginning March 7, Winter Storm Quinn moved into JCP&L's service territory, bringing more high winds and additional wet, heavy snow. The effects of Winter Storm Quinn compounded the effects and damage previously caused by Winter Storm Riley. For instance, areas within the Northern Region impacted significantly during Winter Storm Riley were again impacted in Winter Storm Quinn. Additionally, restoration activities were stopped for nearly 16 hours in the Northern Region when road conditions were too hazardous for travel. In total, 27 hours (or greater than one day) were dedicated to employee and contractor safety precautions in order to ensure safe restoration.

Finally, as the event unfolded the changing dynamics of coordinated restoration efforts prioritized clearing more than 1,900 roadways to open roads blocked by electrical equipment and wires and restoring nearly 250 schools impacted by the event, necessarily causing additional delays in restoration to customers. Priority restoration was then given to customers who originally lost power in Winter Storm Riley.

Any one of these types of challenges on its own can be expected to cause delays in restoration. Combined, they create a very difficult hurdle to clear.

Q. How does Riley/Quinn compare to Hurricane Irene and the October 2011 snowstorm?

A. Riley/Quinn was the first event of its size experienced by JCP&L since Hurricane Sandy in 2012. Similar to Hurricane Irene and the October 2011 snowstorm, trees were the primary cause of the damage and customer outages in Riley/Quinn. Although similar to Hurricane Irene and the October 2011 snowstorm, Riley/Quinn resulted in more damage as evidenced by the number of pole and miles of wire replaced (Irene: 360 poles/47 miles vs. October 2011 snowstorm: 612 poles/136 miles vs. Riley/Quinn: 805 poles/69 miles respectively). Further, more line workers (2,080/3,100/3,400 FTEs respectively) as well as resources (4,700/5,700/7,000 FTEs respectively), in total, supported restoration efforts for Riley/Quinn.

Q. Did JCP&L experience any additional weather impacts in March 2018?

A. Yes. Approximately one week after JCP&L finished power restoration from Riley/ Quinn, Winter Storm Toby hit on March 21, 2018. The Northern Region experienced winds between 20 to 30 mph and received up to six inches of snow in some areas. The Central Region experienced winds between 30 to 40 mph and received up to twelve inches of snow in some areas. This storm event caused approximately 70,836 customer interruptions with 4,492 customer interruptions in the Northern Region and 66,344 customer interruptions in the Central Region and resulted in issuance of 183 crossarms, 47 poles, 27 transformers, and 19,152 feet (3.63 miles) of replacement wire. Similar to other events, much of the damage was caused by trees or limbs falling on circuits thereby causing poles to break. Nearly, 4,100 FTEs (approximately 1,900 line workers) worked to restore power to JCP&L's customers.

Q. Did JCP&L incur extensive capital costs and O&M expenses because of Riley/Quinn and Toby?

A. Yes. JCP&L incurred $59.1 million of capital costs and $133.2 million of O&M expenses specifically related to Riley/Quinn and Toby. By comparison, Hurricane Irene caused the Company to incur approximately $25 million of capital costs and $52 million of O&M expenses. 81% of the Riley/Quinn and Toby capital costs and 94% of the expense corresponded with the labor costs for both (i) JCP&L workers and FirstEnergy affiliated workers, and (ii) contractors who worked to restore service to JCP&L customers.

Q. You previously indicated that 2019 also was a difficult weather year. Please explain.

A. Yes. In 2019, the Northern Region and Central Region experienced a significant increase in major event days, as compared to the average annual number of major event days for period of 2016 through 2018. Major events, by regulation (N.J.A.C. 14:5-1.2, Definitions), include not only events impacting greater than 100,000 customers but also, the time related to providing mutual assistance, and the time associated with declared states-of-emergency. In my testimony below, I will further describe two major events impacting greater than 100,000 customers in 2019. This includes Winter Storm Quiana in February; and most recently, Winter Storm Ezekiel in December.

Q. Please describe the impact of Winter Storm Quiana on JCP&L's system.

A. On February 24 and continuing through February 28, 2019, JCP&L's service territory began to experience customer outages due to Winter Storm Quiana. Specifically, a strong, low-pressure system moved across New Jersey over a two-day period producing winds with maximum gusts of 60 mph.

Quiana, for which the Governor declared a state-of-emergency, caused approximately 110,755 customer interruptions with 75,036 outages in the Northern Region and 35,719 customer interruptions in the Central Region. There were over 900 outage orders associated with the 110,755 customers experiencing service interruptions throughout the JCP&L system. JCP&L activated its hazard process on February 25, 2019 to identify and make-safe hazard conditions and to assess system damage. JCP&L worked alongside county officials to implement its road opening process, and approximately 143 roads were opened. JCP&L next focused on restoring 22 schools impacted by Winter Storm Quiana. Winter Storm Quiana required the issuance of 218 crossarms, 81 poles, 62 transformers, and 34,053 feet (6.45 miles) of wire and cable. Requests were made through the RMAGs, FirstEnergy affiliated companies, outside contractors, and other New Jersey electric companies in order to obtain resources to expedite restoration. In total, 307 mutual assistance/contractor line workers were secured to support restoration efforts.

Q. Please describe the impact of Winter Storm Ezekiel on the Company's system.

A. The effects of Winter Storm Ezekiel resulted in ice and snow accumulation concentrated in the Northern Region over a three-day period from December 1 to December 3, 2019. In total the Northern Region received over a quarter of an inch of ice and over a foot of heavy wet snow. Due to freezing temperatures, the ice on the power lines was unable to melt before the wet snow started accumulating. Wind gusts upwards of 60 mph were recorded in the JCP&L Northern Region on December 2. The weather impact of Winter Storm Ezekiel was much greater than forecasted and caused much more damage than originally anticipated. In total, JCP&L experienced 138,141 customer interruptions with 128,949 customer interruptions in the Northern Region and 9,192 customer interruptions in the Central Region.

Q. Did JCP&L experience any complications with restoration during Winter Storm Ezekiel?

A. Yes. Many of the customer outages in the Northern Region were as a result of trees due to the additional weight from the ice and wet snow. Reports from the field in heavily treed areas of the Northern Region indicated that tree branches were breaking, and entire trees were falling due to the extra weight of the ice and wet snow. For the safety of the personnel working to restore customer outages, restoration to some areas was delayed as a result of the dangerous snow and ice conditions.

Q. Please describe the damage experienced and restoration efforts during Winter Storm Ezekiel.

A. To address the customer outages, JCP&L obtained additional line worker resources as early as December 2. In the end, JCP&L received assistance from its on-site contractors, off-site contractors, all nine FirstEnergy affiliated companies, as well as the other three New Jersey electric distribution companies, Public Service Electric & Gas, Atlantic City Electric and Orange & Rockland, totaling over 1,000 line workers. In total, JCP&L engaged more than 2,000 line, hazard, damage, forestry and other support personnel during Winter Storm Ezekiel. Winter Storm Ezekiel required the issuance of approximately 470 crossarms, 110 poles, 80 transformers, 390 cutouts, and 65,600 feet (12.4 miles) of wire and cable. Over 5,800 trouble orders and nearly 1,600 outage orders were generated.

Q. Was the E-Plan and ICS used with respect to each of the major events?

A. Yes. JCP&L implemented its E-plan and ICS for purposes of storm planning, recovery, and restoration at a level that corresponds to the severity of the forecasted and manifested event.[17]

Q. In your experience, has any of the damage or restoration times addressed during major events, been exacerbated by a failure of the Company to fully implement its I&M programs?

A. No. The Company's I&M programs were fully implemented during the years in question and did not contribute to the damage or cause any restoration delays. This would be particularly relevant with respect to our vegetation management programs.

[17] I note, however, that in the case of mutual assistance major events that more severely or exclusively affect another EDC's or an out-of-state utility's service territory, implementing ICS may not be necessary if the event is not directly impacting the Company's service territory.

X. DISTRIBUTION SYSTEM RELIABILITY PERFORMANCE

Q. Please discuss the reliability performance of JCP&L's distribution system.

A. Let me begin by saying the Company's annual reliability performance is described and discussed in great detail in the Annual System Performance Reports (collectively "ASPRs" and individually, each an ASPR) that are filed each May with the Board. The Company's ASPR for 2019 will be filed with the Board by May 31, 2020.

During the period 2016-2019, reliability performance in both the Northern and Central regions was better each year than the required minimum reliability standards for SAIFI and CAIDI. These standards were last established by the BPU in August 2015 (based on the Company's 2010-2014 average performance).

During the same 2016-2019 period, the Northern Region also performed favorably in 2016 and 2017 with respect to its SAIFI and CAIDI benchmarks and the Central Region also performed favorably with respect to its SAIFI benchmark in 2017 and its CAIDI benchmark in 2016. However, in 2018, while meeting or exceeding their respective minimum reliability requirements, neither region met its SAIFI and CAIDI benchmarks. While the 2019 ASPR will not be finally compiled, completed and filed with the Board until the end of May 2020, Table 14A and Table 14B below reflect a preliminary summary of the respective assigned benchmark and minimum standards in effect for 2019.

Table 14A

	CAIDI			
	Benchmark Reliability Level	Minimum Reliability Level	2018 Actual Minutes	2019 Actual Minutes
JCP&L Overall	N/A	N/A	120	113
JCP&L Northern	128	151	133	126
JCP&L Central	101	110	110	102

Table 14B

	SAIFI			
	Benchmark Reliability Level	Minimum Reliability Level	2018 Actual (Average Interruptions, per customer)	2019 Actual (Average Interruptions, per customer)
JCP&L Overall	N/A	N/A	1.18	1.20
JCP&L Northern	1.18	1.35	1.29	1.29
JCP&L Central	1.01	1.22	1.22	1.14

Q. Does JCP&L's performance comply with the BPU's regulatory requirements for reliability?

A. Yes. Despite the challenges, which I will discuss below, JCP&L's distribution system continues to meet the reliability standards that have been set by the BPU.

Q. Has the Company reviewed and considered the potential causes of the trend during this period of compliant reliability performance?

A. Yes. As explained in the Company's ASPR for 2018, JCP&L has experienced a relatively significant increase in the number of minor weather days in 2018 as compared to its review and analysis of the 2014 – 2017 annual average in both the Northern and Central Regions, of 42% and 27% respectively. In 2019, JCP&L also experienced an elevated number of minor weather days, with an increase in both the Northern and Central Regions of 22% and 19%, respectively, as compared with the 2014-2017 annual average.

Q. What do you mean by "minor weather days"?

A. JCP&L utilizes the concept of minor weather days to distinguish between a blue-sky day, where there is no or typical inclement weather and a major event, which the BPU defines in its regulations and which is excluded from the calculation of SAIFI and CAIDI. JCP&L utilizes the concept of minor weather days to indicate periods when either the entire service territory or specific operating districts experience adverse weather conditions that cause customer outages but do not reach the threshold to qualify as a major event.

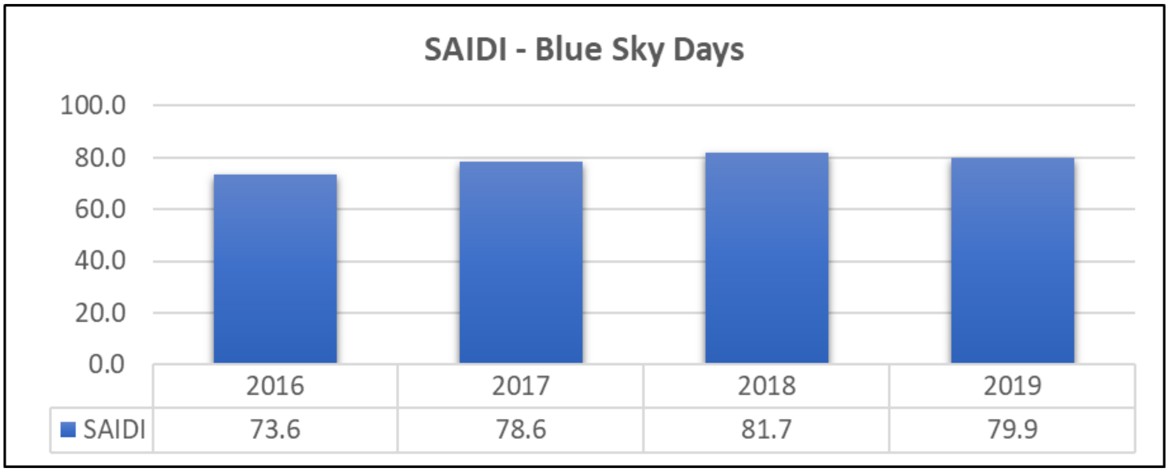
Q. Is a minor weather day just a subjective determination?

A. No. JCP&L has developed criteria for the designation that helps to distinguish the day from a blue sky day. The criteria for retrospectively designating the weather experience over a period of time as a minor weather day includes: (A) Winter precipitation, meaning (i) ice in the form of 0.25 inch or more of freezing rain within a 24-hour period; (ii) ice in the form of 0.10 inch or more of freezing rain combined with wind gusts of 15 mph or more; and (iii) snow in the form of four inches or more of snow within a 24-hour period (wet or dry snow); (B) Wind, meaning wind gusts are forecasted to be 40 mph or higher; and/or (C) Temperature, meaning the minimum temperature is at or below zero degrees Fahrenheit or at or above 90 degrees Fahrenheit.

Q. Why does the Company use the minor weather days concept?

A. It provides a context and a tool for better understanding the drivers of reliability performance. For instance, the Company's blue sky day SAIDI has remained relatively stable during the period of 2016 through 2019, as seen in the table below:

Table 15

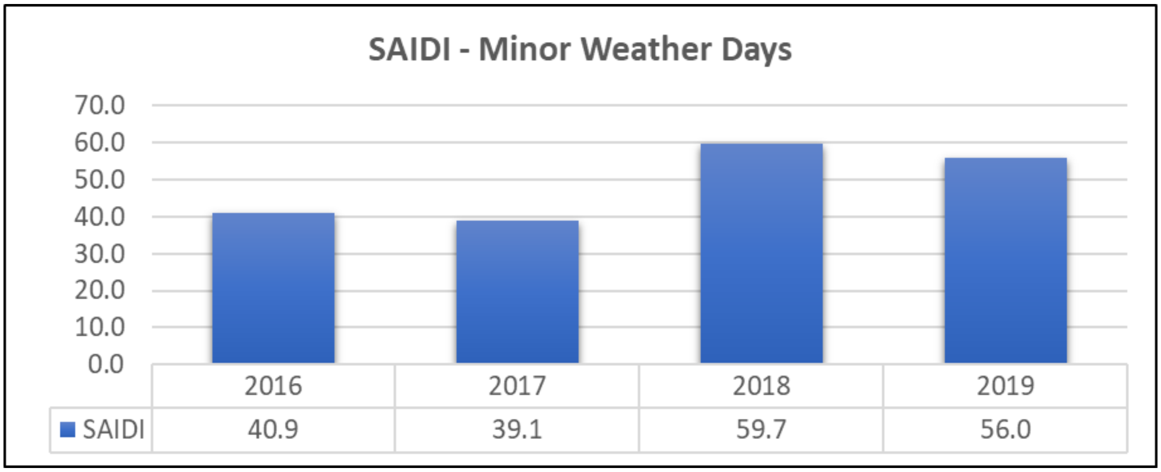


Let me explain that SAIDI means the "System Average Interruption Duration Index," which is calculated by dividing the sum of all customer outage durations by the number of customers served. Thought of another way, it is the product of multiplying CAIDI (Customer Average Interruption Duration Index) by SAIFI (System Average Interruption Frequency Index). SAIDI provides a picture of outage duration on the system. CAIDI depicts average outage duration per customer and SAIFI calculates the frequency of outages on a customer basis. By using SAIDI we can better consider overall system impacts under certain conditions.

Q. Compared to the blue sky day SAIDI, did you look at SAIDI for minor weather days?

A. Yes. JCP&L's minor weather day SAIDI has trended upward during the same period as shown in the next table below:

Table 16



The following tables illustrate the number of minor weather days JCP&L experienced during this time period as well as the SAIDI impacts per minor weather day.

Table 17

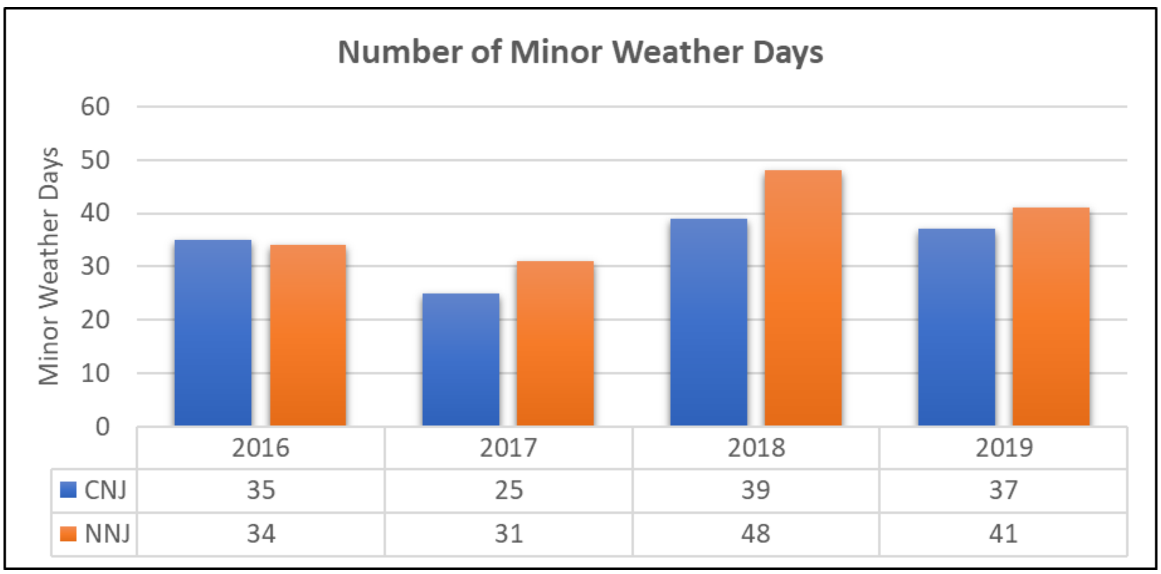
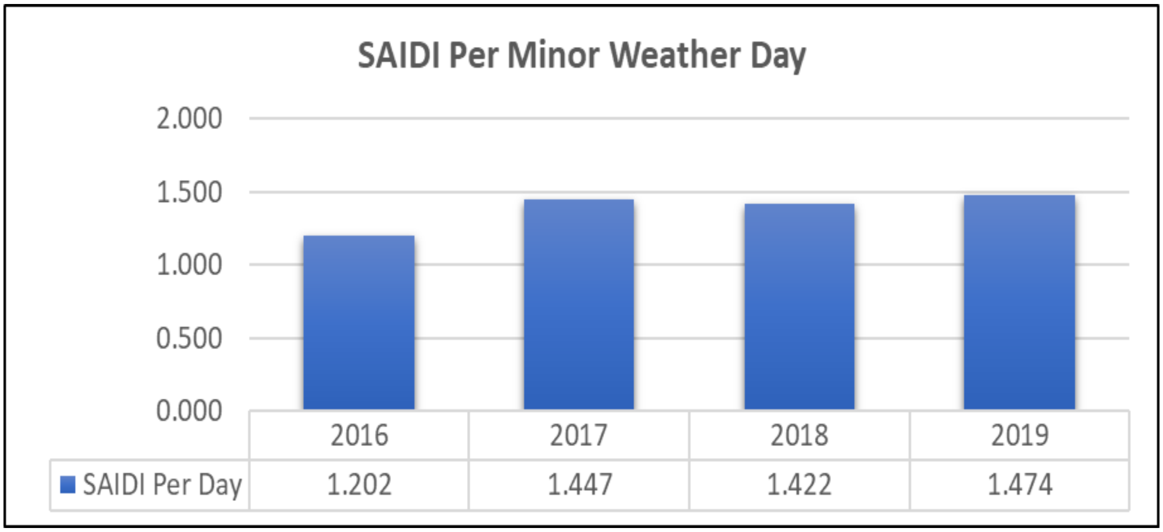


Table 18



Considered together, the data displayed in theses charts suggest that the increased SAIDI for minor weather days correlates with an upward trend in both the frequency and severity (as reflected in the SAIDI per day data) patterns of minor weather days since 2016.

Q. What does this correlation mean to the Company's reliability performance?

A. While not definitive, analytical correlations can help us to better understand the drivers of certain kinds of results. In this instance, the correlation appears to shed light on the Company's statistical reliability performance. Where Blue Sky SAIDI remains relatively flat through the period, the increasing trend relative to minor weather days, which also appears to track the trend line of an increasing number of major event days, indicates that the frequency of the occurrence and the severity of minor weather days (over which the Company has no control) negatively impacts reliability and does so significantly.

Q. How significantly?

A. The best way to show the significance, is to examine the contribution of these minor event days to the Company's SAIFI performance. SAIFI, which calculates average frequency of outages on a per customer basis, is a more sensitive indicator of a customer's experience.

Looking at the minor weather data for 2018, it appears that the SAIFI for minor weather days accounted for 33% (or 0.431 occurrences) of the Northern Region's total SAIFI and 28% (or 0.307 occurrences) of the Central Region's total SAIFI.

Looking at the minor weather data for 2019, it appears that the SAIFI for minor weather days accounted for 35% (or 0.449 occurrences) of the Northern Region's total SAIFI and 34% (or 0.386 occurrences) of the Central Region's total SAIFI in each case an increase over the 2018 experience.

Q. What is the significance of this data?

A. Again, this data provides perspective that confirms that a significant driver of the trend in the Company's reliability performance is weather that, while not rising to the level of being a major event, is more severe and occurring more frequently than what our experience has suggested is a more normal pattern of weather for our regions. The impacts of these events tend to demonstrate how a small number of non-reportable events can impact the reliability results. Even though these are not major events that can be excluded from the calculation of SAIFI, they have similar "beyond the Company's control" characteristics that are not likely to be reasonably addressed or mitigated by system or process adjustments because the minor weather days are unavoidable and data indicates we are experiencing more of them. I would also like to note that, in 2019, approximately 36% of customer-minutes of interruption incurred on minor weather days were caused by tree-related damage, increasing from approximately 31% in 2018. The Company, as part of the JCP&L Reliability Plus program as well as through its regular vegetation management program, continues to undertake significant efforts to mitigate tree-related damage to its system, planning to spend in total on vegetation management during the Test Year, as follows:

Table 19

Year	O&M	Capital	Total
July to December 2019	$9,867,527	$23,420,412	**$33,287,939**
January to June 2020	$7,890,712	$23,267,228	**$31,157,940**
TOTAL	**$17,758,239**	**$46,687,640**	**$64,445,879**

The following additional tables may further help to explain my point, these tables show the SAIFI contribution separated by the type of day (*i.e.*, blue sky, top ten minor weather day by SAIFI, and other minor weather days).

Table 20

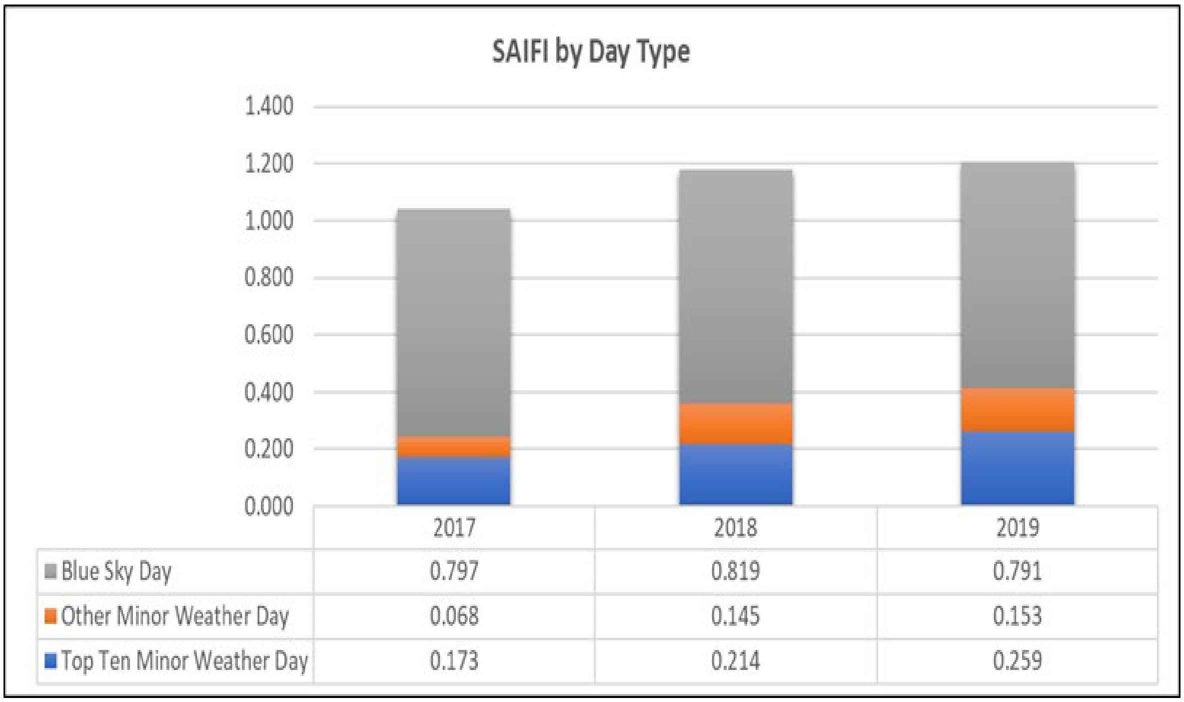
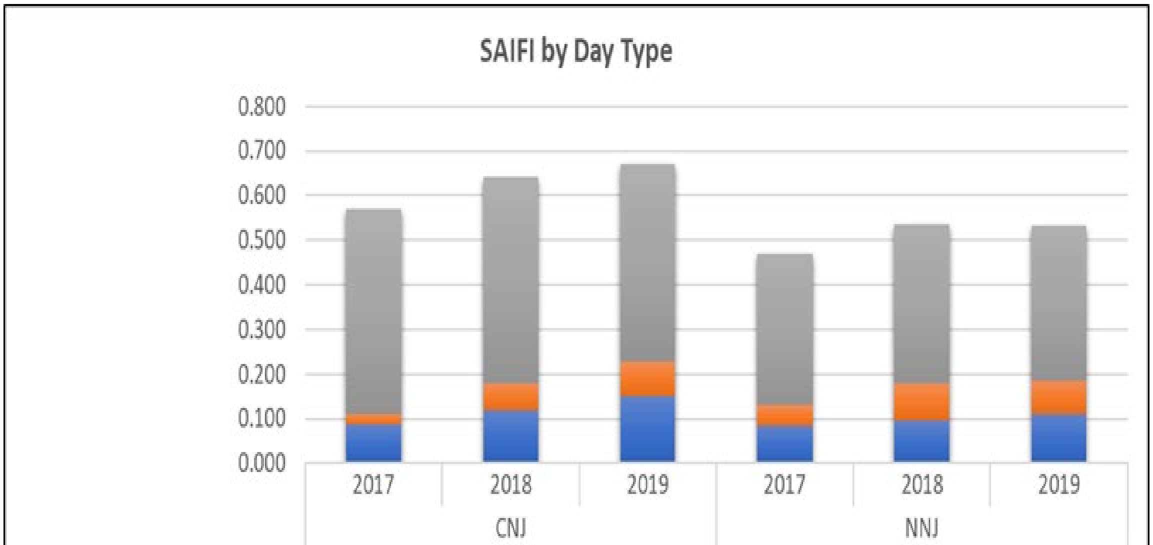


Table 21



	CNJ 2017	CNJ 2018	CNJ 2019	NNJ 2017	NNJ 2018	NNJ 2019
Blue Sky Day	0.457	0.462	0.443	0.340	0.357	0.348
Other Minor Weather Day	0.023	0.061	0.077	0.045	0.083	0.076
Top Ten Minor Weather Day	0.089	0.118	0.150	0.084	0.096	0.110

From these tables, one can see that SAIFI from minor weather days (blue + orange) has increased from 2017 through 2019, whether looking at the overall JCP&L experience (Table 20) or when separating the data out by regions (Table 21). Moreover, the contribution to overall SAIFI for the top ten minor weather days of each region (blue) has increased significantly each year, both absolutely and as a percentage of total SAIFI, suggesting that the severity of the non-excludable weather days has been increasing year-to-year.

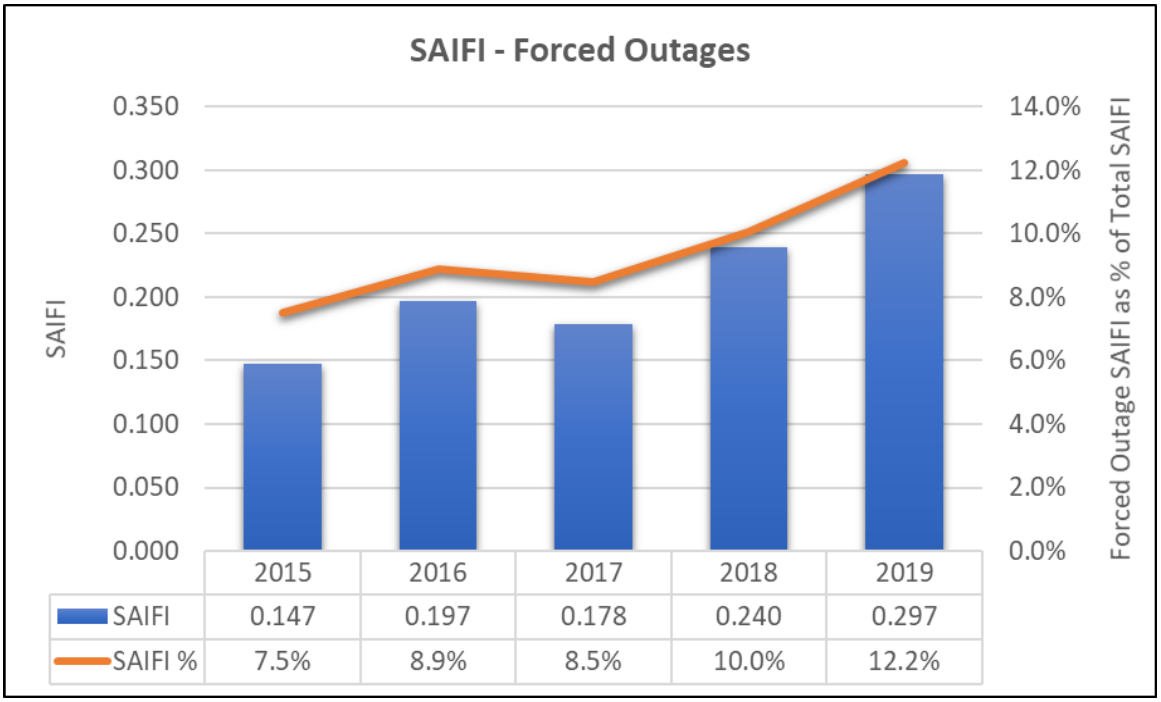
Q. Does the Company have any other insights regarding these changes?

A. Yes. I think the Company's experience should be considered in light of the available meteorological science, understanding and insights regarding the increasing frequency and intensity of the recent weather experience. In this regard, however, I would refer and rely on the testimony of one of FirstEnergy's in-house meteorologists, Mr. Thomas Workoff (Exhibit JC-8) for an explanation.

Q. Does the Company see any other changes that provide insight regarding its reliability performance?

A. Yes. JCP&L and all of FirstEnergy have put a premium on safety – that of its employees, its customers and the general public. In this context, I think it is relevant to mention that JCP&L has seen an increase in the condition that it characterizes as forced outages. This experience refers to situations where an outage condition or an electric system condition is not addressed while the system is energized. As a matter of enhancing the focus of our employees on safe work practices (particularly in the aftermath of a serious employee accident), the Company has worked with its line and substation employees to provide a wider-range of latitude within which to use their practical judgement in determining whether and when to work a line or substation condition in an energized or non-energized mode. JCP&L has subsequently noticed that this increased flexibility in favor of enhancing already-safe work practices has a pronounced impact on SAIFI as shown in the following table:

Table 22



Clearly, this step towards increased line and substation worker safety has a necessary, albeit adverse, impact on reliability performance.

Q. Do you have anything else to add?

A. Yes. I think, as I mentioned, earlier, that the combination of data about the JCP&L service territory's geographic dimensions and diversity, the degree of its forestation, and the rise of the impacts of weather provide a useful perspective from which to consider the Company's investment of capital, O&M expenses, deferred storm costs, operations, maintenance and performance (including storm recovery and restoration). The increasing impact of weather results in increased storm-related expense needing to be reflected in the Company's rates and requiring an increasing storm deferral. Anticipating that as storm activity increases, the deferral will grow, I think the operational evidence discussed in this testimony supports Mr. Fakult's observation (Exhibit JC-2) about the impact of deferral on cash-flow, and the proposal discussed by Mr. Mader (Exhibit JC-3) and Ms. Pittavino (Exhibit JC-4), as to a more appropriate form of real-time recovery and accelerated recovery of the deferred storm costs already incurred but not yet recovered.

XI. PROPOSED CHANGES TO TARIFF APPENDIX A ("Tariff Appendix A")

Q. What is Tariff Appendix A?

A. Tariff Appendix A is a schedule (in Part II of the JCP&L Tariff for Service) of applicable material unit costs used for purposes of calculating the charges to customers or developers for underground construction of various types.

Q. Have you prepared schedules in connection with this aspect of your testimony?

A. Yes, I have. Schedule DLP-2 provides the proposed form of the revised Appendix A containing the proposed changes I will discuss herein. Schedule DLP-3 provides the current version of Appendix A as it currently appears in the Tariff. Schedule DLP-4 shows the man-hour and vehicle rate calculation for 2020. Schedule DLP-5 provides labor and material overhead rates. Schedule DLP-6 contains a comparison of the current and proposed Appendix A pricing for an underground (URD) installation on a refundable and non-refundable basis.

Q. Please describe the changes that are proposed for Tariff Appendix A of the Tariff.

A. The Company is proposing to update certain charges to reflect current labor costs, material costs, and vehicle rates, with applicable overheads, and other modifications pertaining to Residential Electric Underground Extensions, also referred to as "URDs". In this regard, my testimony supplements and supports the testimony of Yongmei Peng submitted herewith (Exhibit JC-12). The proposed changes result in increased pricing for non-refundable URD installations ranging from 13%-19%, and a 28% increase for refundable installations.

Q. Please explain the basis for the Company's proposed modifications in Schedule DLP-2 related to Tariff Appendix A.

A. In Schedule DLP-2, all of the charges are being updated to reflect the Company's current costs. The methodology used to develop the updated charges was the same as the methodology used in the Company's compliance filing pursuant to the Board of Public Utilities Rule Adoption, Docket No. AX12070601, effective December 21, 2015.

Charges were developed for four average building lot categories by performing a regression analysis to derive the average charge for a building lot based on 26 example projects. Similar to prior filings, charges were also included for primary terminations, including the additional charge for "looping" primary cable in subdivisions with 25 or more single family homes, and the costs associated with installing fault indicators.

Q. Please discuss the changes to labor and vehicle rates.

A. The updated charges also reflect the current labor and vehicle rates for JCP&L with applicable overheads. Schedule DLP-4 through Schedule DLP-6, which were prepared by the Engineering department, demonstrate a significant increase in labor rates based on market rates over the course of the past five years. Over that time period, the direct average rate for a LC&M Chief/1st class has increased by approximately 26%. This overall increase reflects annual increases based on the applicable collective bargaining agreements. The vehicle rates have also been updated to use 2020 vehicle rate data, which reflects vehicle-related costs that have increased since the last revision to Tariff Appendix A in connection with the 2016 Base Rate Filing.

Q. Please discuss the changes to material costs.

A. The updated material costs found in Schedule DLP-4 through Schedule DLP-5, are based upon FirstEnergy standards, which are used for construction at JCP&L. The costs in Schedule DLP-4 and Schedule DLP-5 are derived from base units known as Compatible Units ("CUs"). CUs represent discrete job elements of material and/or labor needed for the loading, unloading, transportation and installation of the materials. CUs are combined to form the series of tasks that are required to complete a particular job, such as the installation of an electric service in a URD, which, in turn, allows for the computation of the costs for that particular job.

There are a number of reasons for the increased material costs. Since 2016, there has been a significant cost increase in base material items. Copper, aluminum, steel and products derived from oil (wire covering, insulating materials and other plastic compounds) have all experienced an overall increase since 2016.

Q. How did the Company calculate the new charges associated with updating man-hours?

A. The applicable man-hours associated with the various construction units have been updated since the Company's 2016 Base Rate Filing. The process of updating the construction units and their associated labor and material costs was started in November of 2019 using contractual labor rates. Updates were based on current FirstEnergy's Customer Request Work Scheduling System ("CREWS") software, which is discussed further below. Cost estimates are developed based on the design of the project after the appropriate CUs and/or macro units ("MUs") have been assigned to the particular line span and geographic points set forth on the work request ("WR").

Q. What is meant by the terms CUs, MUs and points and spans?

A. As mentioned earlier, the costs of a project are derived from base units known as CUs. The CUs represent discrete job elements of material and labor needed for the loading, unloading, transportation and installation of the material product(s). The CUs are combined to form a series of tasks required to complete a job such as the installation of a transformer and service. In other words, a CU is a standardized assembly that represents the labor tasks, vehicle/equipment hours, and materials required for a construction, maintenance, or operations activity. It may also include facility attributes, accounting information, and unit-of-property information.

An MU, by comparison, is two or more CUs grouped into a logical design or construction.

A point or span is the location where materials are installed, removed, or maintained and/or labor is performed as directed by a WR.

In addition, CREWS uses vouchers to identify additional costs associated with a WR, which may be condition sensitive (such as rocky sub-strata that requires special efforts, or the need in a particular municipality for police traffic control) that cannot be determined based on the CU.

The CUs, MUs and vouchers are put together on/in a point and span design in CREWS to develop an estimate of the costs for the project.

Q. What is CREWS?

A. CREWS is the scheduling system that JCP&L uses to develop cost estimates for construction projects. CREWS is a software tool used by designers to layout WRs and adds necessary vehicle, labor and applicable over-heads to provide project cost estimates.

Q. How are estimates of project cost developed in CREWS?

A. Points and spans, as described above, are used in CREWS designs to lay out the construction project. As the project design is developed an estimate of the costs of the project is also developed.

Q. Does the Company propose to eliminate any component of Tariff Appendix A?

A. Yes. JCP&L proposes to eliminate the Alternate Service Location Charge (*see* Schedule DLP-3 at "B. Additional Charges" at subpart "4."), which is currently applicable in URD Single Family Developments if the Developer chose to locate the point of attachment for a home's electrical service at a point that was not nearest to the transformer.

Beginning in 2018, all underground cable is required to be installed in conduit for reliability and maintenance purposes. With the conduit system, a secondary enclosure acting as a wire "pull box" for cable installation, is installed between every two houses. This allows flexibility to serve homes from either of two secondary enclosures, eliminating the need to charge for an Alternative Service Location Charge.

Q. Do the Company's proposed revisions to Tariff Appendix A add anything that was previously not included in Tariff Appendix A?

A. Yes. As shown in Schedule DLP-2, JCP&L proposes to include within Tariff Appendix A the applicable charge for the installation of LED streetlights in URD Single Family Developments. LED streetlights have been available since January 1, 2017 under Tariff Rider LED Street Lighting Service, which are applicable to overhead and underground installations. Although the applicable LED street lighting charges are currently charged to URD developers, the Company proposes to refer to such charges more specifically in Tariff Appendix A in order to avoid confusion and promote clarity as to the entire scope of charges that may be applicable to URDs.

XII. <u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes.

Appendix A

Experience and Qualifications - Dennis L. Pavagadhi

I am the Director, Operations Services at Jersey Central Power & Light Company, for whom I have worked for over 24 years. I am responsible for the work performed by JCP&L's 14 local line shops constructing, inspecting and maintaining the Company's distribution line plant, JCP&L's local Regional Engineering department, which performs distribution level system planning, reliability, design and project management functions, as well as the Company's Claims department. I have been in my current position since October 2019. Prior to my current position, I was the Director, Operations Support beginning in 2014. In that role, I was responsible for JCP&L's two Distribution Control Centers, Regional Work Managements, and the Substation Department at JCP&L.

Prior to 2014, I was the Manager of Engineering Services beginning in 2005. In that capacity, I was responsible for the distribution and sub-transmission planning, protection, new business and reliability engineering groups for the Morristown. In addition, I also managed the asset records, mapping, joint use, rights-of-way and project management groups within the engineering department. Prior to 2005, I was held various engineering and managerial positions at the Company.

Prior to joining JCP&L, I served as an engineer for Decision System Technologies at Picatinny Arsenal and John Brown Engineering & Construction. At Decision System Technologies, I designed defense systems. At John Brown Engineering & Construction, I designed various electrical and mechanical systems.

I am a licensed Registered Professional Engineer in New Jersey and Pennsylvania, and a Certified Energy Manager.

I hold a Bachelor of Science degree in Engineering from the New Jersey Institute of Technology, a Master of Science degree from the New Jersey Institute of Technology and a Master of Science degree in Management from the College of Saint Elizabeth.

JERSEY CENTRAL POWER & LIGHT
DISTRIBUTION-OPERATIONS & MAINTENANCE EXPENSE

12 MONTHS ENDING JUNE 2020

Line Item	FERC Acct	FERC Acct Desc	AMOUNT	
O&M - Distribution	580	OpSupervision&Engrg	89,279	
	581	LoadDispatching	1,283,749	
	582	StationExp	586,634	
	583	OvhdLineExpenses	1,386,851	
	584	UndergroundLineExp	3,370,232	
	585	StreetLighting	-	
	586	MeterExpenses	1,124,469	
	588	MiscDistributionExp	17,308,525	
	589	Rents	6,177,282	
	590	MaintSupervsn&Engrg	1,617,484	
	591	MaintStructures	119,074	
	592	MaintStationEquip	10,654,296	
	593	MaintOverhdLines	36,695,799	
	594	MaintUndergroundLine	3,597,029	
	595	MaintLineTransformer	350,274	
	596	MtcStreetLght&SigSys	3,006,789	
	597	MaintMeters	4,870,664	
	598	MaintMiscDistribPlt	1,578,429	
			93,816,859	(a)
O&M - Customer Accounts	901	Supervision	38,021	
	902	MeterReadingExpense	14,235,371	
	903	CustRcrd&CollectExp	14,453,393	
	904	UncollectibleAccts	119,609	
	905	MiscCustAcctsExp	1,436,938	
			30,283,331	(b)
O&M - Customer Service	907	Supervision	368,340	
	908	CustAssistExp	1,214,314	
	909	Info&InstrctAdverts	2,400	
	910	MiscCustServ&InfoExp	9,383,308	
			10,968,363	(c)
O&M - Sales Expense	911	Supervision	56,383	
	913	Advertising Expense	-	
			56,383	(d)
TOTAL DISTRIBUTION O&M			135,124,936	(e)

(a) Reference schedule CAP-1, column 3, line 8.
(b) Reference schedule CAP-1, column 3, line 9.
(c) Reference schedule CAP-1, column 3, line 10.
(d) Reference schedule CAP-1, column 3, line 11.
(e) Distribution O&M is exclusive of expenses associated with reconcilable riders and A&G expenses.

Appendix A - Unit Costs of Underground Construction
Single Family Developments

Appendix A - Residential Electric Underground Extensions
The Applicant shall pay the Company the amount determined from the following table:

A. Base Charges	Average Front Footage Per Lot			
1. Single Family	<= 125 Ft	126-225 Ft	226-325 Ft	>= 326Ft
Nonrefundable charge per building lot • With Applicant providing all trenching and road crossing conduits	$ 361.00	$ 428.00	$ 495.00	$ 881.00
Refundable deposit based on equivalent overhead construction	$ 828.00	$1,656.00	$2,484.00	$4,140.00

2. Lots requiring 1Φ primary extension

Without primary enclosure	$1,532.00
With primary enclosure	$4,236.44

3. Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 KVA, etc. — Charge to be based on differential cost according to unit costs specified in Exhibits I through III

B. Additional Charges

1. Street Lights - SVL

16 foot fiberglass pole with standard colonial post top luminaire	$ 365.00
16 foot fiberglass pole with ornate colonial post top luminaire	$1,026.00
30 foot fiberglass pole with cobra head luminaire on 6 foot bracket	$1,126.00
12 foot 9 inch ornate fiberglass pole with ornate colonial post top luminaire	$2,567.00
12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire	$3,234.00
- LED	
16 foot Fiberglass pole with colonial post top luminaire	$ 577.00
30 foot fiberglass pole with Cobra Head	$1,164.00
12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire	$2,118.00

2. Multi-Phase Construction $1.28 per added phase per foot

3. Pavement cutting and restoration, rock removal, blasting, difficult digging, and special backfill — At actual low bid cost with option of Applicant to contract for as limited by NJAC

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit I - Unit Costs of Underground Construction Single-Phase 15 kV

Item	Unit	Total Cost
1. Primary cable 1/0 aluminum	per foot	$ 3.86
2. Secondary cable 3/0 aluminum	per foot	2.48
350 MCM aluminum	per foot	5.02
500 MCM aluminum	per foot	8.09
750 MCM aluminum	per foot	11.04
3. Service - 200 amp and below	per foot	2.48
50 feet complete	each	614.14
4. Primary termination - branch	each	1,372.50
5. Primary junction enclosure - branch	each	2,703.80
6. Secondary enclosure	each	646.61
7. Conduit - 3 inch PVC	per foot	3.94
Conduit - 4 inch PVC	per foot	4.75
8. Street light cable - # 12 cu. duplex	per foot	2.93
9. Transformers - including fiberglass pad		
25 kVa – single-phase	each	2,616.27
50 kVa – single-phase	each	2,921.40
75 kVa – single-phase	each	3,305.99
100 kVa – single-phase	each	3,680.90
167 kVa – single-phase	each	4,386.08
25 kVa – single-phase Dual Voltage	each	3,035.23
50 kVa – single-phase Dual Voltage	each	3,299.85
75 kVa – single-phase Dual Voltage	each	4,093.62
10. Street light poles		
16 foot post top fiberglass pole	each	576.58
30 foot fiberglass pole	each	1,163.74
12 foot 9 inch ornate fiberglass pole	each	2,117.95
11. Street light luminaire – cobra head SVL	each	539.26
12. Post top luminaire – SVL		
50, 70, 100 & 150 watt colonial style	each	365.76
70 & 100 watt ornate colonial style	each	1,026.42
70 & 100 watt ornate acorn style	each	1,693.36
13. Primary splice – # 2 aluminum	each	188.84

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit II - Unit Costs of Underground Construction Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Primary cable – three-phase main feeder	per foot	$ 24.93
2.	Secondary cable - 4-wire 350 MCM aluminum	per foot	8.60
3.	Service cable - 4-wire 350 MCM aluminum	per foot	8.92
4.	Primary termination - main		
	# 2 aluminum three-phase	each	3,365.54
	1000 MCM aluminum three-phase	each	4,961.19
5.	Primary junction - main	each	4,660.04
6.	Primary switch - main		
	PMH-9	each	34,679.04
	PMH-10	each	30,136.80
	PMH-11	each	31,658.44
	PMH-12	each	38,639.32
7.	Conduit - 5 inch PVC	per foot	5.98
	- 6 inch PVC	per foot	7.40
8.	Transformers - including concrete pad		
	75 kVa three-phase	each	6,297.08
	150 kVa three-phase	each	6,980.84
	300 kVa three-phase	each	8,835.18
	500 kVa three-phase	each	10,988.05
9.	Primary splice – 15 kV three-phase cable	each	433.75

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit III - Unit Costs of Overhead Construction
Single and Three-Phase 15 kV

Item	Unit	Total Cost
1. Pole line (including 40 foot poles, anchors & guys)	per foot	$ 6.56*
2. Primary wire		
Single-phase – branch	per foot	2.58
Three-phase – main	per foot	12.08
3. Primary wire - neutral	per foot	2.42
4. Secondary cable		
Three-wire	per foot	5.16
Four-wire	per foot	8.45
5. Service		
Single-phase	each	244.60
Single–phase - 200 amp and below	per foot	2.49
Three-phase – up to 200 amp	per foot	4.02
Three-phase – over 200 amp	per foot	6.67
6. Transformers		
25 kVa – single-phase	each	1,453.17
50 kVa – single-phase	each	1,763.05
75 kVa – single-phase	each	2,273.13
100 kVa – single-phase	each	2,635.99
167 kVa – single-phase	each	3,073.14
3- 25 kVa – three-phase	each	3,818.97
3- 50 kVa – three-phase	each	4,748.61
3- 75 kVa – three-phase	each	6,404.91
3-100 kVa – three-phase	each	7,481.49
3-167 kVa – three-phase	each	8,792.94
7. Street light luminaire – cobra head SVL	each	577.38

* Pole line cost to be used = $6.56 / 2 = $3.28

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit III - Unit Costs of Overhead Construction

Single and Three-Phase 15 kV

Item	Unit	Total Cost
8. Street light luminaire – LED – Contributions		
Monthly Contribution Fixture charge of $2.92		
30 W Cobra Head	each	358.38
50 W Cobra Head	each	354.88
90 W Cobra Head	each	403.55
130 W Cobra Head	each	492.97
260 W Cobra Head	each	694.22
50 W Acorn	each	1,295.80
90 W Acorn	each	1,243.30
50 W Colonial	each	619.38
90 W Colonial	each	793.88
Monthly Contribution Fixture charge of $4.68		
30 W Cobra Head	each	209.20
50 W Cobra Head	each	205.70
90 W Cobra Head	each	254.37
130 W Cobra Head	each	343.79
260 W Cobra Head	each	545.04
50 W Acorn	each	1,146.62
90 W Acorn	each	1,094.12
50 W Colonial	each	470.20
90 W Colonial	each	644.70

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Unit Costs of Underground Construction
Single Family Developments

Appendix A - Residential Electric Underground Extensions
The Applicant shall pay the Company the amount determined from the following table:

A. Base Charges

1. Single Family	Average Front Footage Per Lot <= 125 Ft	126-225 Ft	226-325 Ft	>= 326Ft
Nonrefundable charge per building lot				
• With Applicant providing all trenching and road crossing conduits	$ 317.00	$ 370.00	$ 424.00	$ 743.00
Refundable deposit based on equivalent overhead construction	$ 648.00	$ 1,296.00	$1,944.00	$3,240.00

2. Lots requiring 1<I primary extension

Without primary enclosure	$1,412.00
With primary enclosure	$3,553.00

3. Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 KVA, etc. — Charge to be based on differential cost according to unit costs specified in Exhibits I through III

B. Additional Charges

1. Street Lights

16 foot fiberglass pole with standard colonial post top luminaire	$ 196.00
16 foot fiberglass pole with ornate colonial post top luminaire	$ 1,036.00
30 foot fiberglass pole with cobra head luminaire on 6 foot bracket	$ 919.00
12 foot 9 inch ornate fiberglass pole with ornate colonial post top luminaire	$ 2,216.00
12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire	$ 2,579.00

2. Multi-Phase Construction — $1.13 per added phase per foot

3. Pavement cutting and restoration, rock removal, blasting, difficult digging, and special backfill — At actual low bid cost with option of Applicant to contract for as limited by NJAC

4. Alternate Service Location Charge	<= 125 Ft	126-150 Ft	> 150 Ft
With Applicant trenching (Applicant provides 4" PVC conduits)	$ 781.00	$ 966.00	not applicable

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit I - Unit Costs of Underground Construction
Single-Phase 15 kV

Item	Unit	Total Cost
1. Trenching – sole use	per foot	$ 18.10*
2. Primary cable 1/0 aluminum	per foot	3.09
3. Secondary cable 3/0 aluminum	per foot	2.26
350 MCM aluminum	per foot	4.28
500 MCM aluminum	per foot	6.32
750 MCM aluminum	per foot	9.53
4. Service - 200 amp and below	per foot	2.26
50 feet complete	each	593.35
5. Primary termination - branch	each	1,186.67
6. Primary junction enclosure - branch	each	2,141.74
7. Secondary enclosure	each	461.91
8. Conduit - 3 inch PVC	per foot	2.71
Conduit – 4 inch PVC	per foot	3.78
9. Street light cable - # 12 cu. duplex	per foot	2.27
10. Transformers - including fiberglass pad		
25 kVa – single-phase	each	2,372.27
50 kVa – single-phase	each	2,712.84
75 kVa – single-phase	each	3,134.72
100 kVa – single-phase	each	3,507.62
167 kVa – single-phase	each	4,212.86
25 kVa – single-phase Dual Voltage	each	2,657.30
50 kVa – single-phase Dual Voltage	each	3,100.08
75 kVa – single-phase Dual Voltage	each	4,027.74
11. Street light poles		
16 foot post top fiberglass pole	each	414.78
30 foot fiberglass pole	each	933.78
12 foot 9 inch ornate fiberglass pole	each	1,594.42
12. Street light luminaire – cobra head	each	475.66
13. Post top luminaire		
50, 70, 100 & 150 watt colonial style	each	270.92
70 & 100 watt ornate colonial style	each	1,111.68
70 & 100 watt ornate acorn style	each	1,475.19
14. Primary splice – # 2 aluminum	each	133.85

* Joint trench calculation: 0.5 x 18.10 = $9.05

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit II - Unit Costs of Underground Construction
Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Primary cable – three-phase main feeder	per foot	$ 20.63
2.	Secondary cable - 4-wire 350 MCM aluminum	per foot	7.21
3.	Service cable - 4-wire 350 MCM aluminum	per foot	7.62
4.	Primary termination - main		
	# 2 aluminum three-phase	each	2,711.97
	1000 MCM aluminum three-phase	each	3,979.00
5.	Primary junction - main	each	3,866.48
6.	Primary switch - main		
	PMH-9	each	24,893.62
	PMH-10	each	23,973.64
	PMH-11	each	25,170.07
	PMH-12	each	29,774.23
7.	Conduit - 5 inch PVC	per foot	5.01
	- 6 inch PVC	per foot	5.77
8.	Transformers - including concrete pad		
	75 kVa three-phase	each	5,371.11
	150 kVa three-phase	each	6,860.58
	300 kVa three-phase	each	8,264.49
	500 kVa three-phase	each	10,688.83
9.	Primary splice – 15 kV three-phase cable	each	340.30

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit III - Unit Costs of Overhead Construction
Single and Three-Phase 15 kV

Item	Unit	Total Cost
1. Pole line (including 40 foot poles, anchors & guys)	per foot	$ 5.34*
2. Primary wire		
Single-phase – branch	per foot	1.96
Three-phase – main	per foot	9.82
3. Primary wire - neutral	per foot	1.85
4. Secondary cable		
Three-wire	per foot	4.07
Four-wire	per foot	6.60
5. Service		
Single-phase	each	196.00
Single–phase - 200 amp and below	per foot	2.00
Three-phase – up to 200 amp	per foot	3.09
Three-phase – over 200 amp	per foot	5.20
6. Transformers		
25 kVa – single-phase	each	1,358.02
50 kVa – single-phase	each	1,715.76
75 kVa – single-phase	each	2,471.51
100 kVa – single-phase	each	2,693.43
167 kVa – single-phase	each	3,625.21
3- 25 kVa – three-phase	each	3,657.43
3- 50 kVa – three-phase	each	4,730.65
3- 75 kVa – three-phase	each	6,994.46
3-100 kVa – three-phase	each	7,660.22
3-167 kVa – three-phase	each	10,455.56
7. Street light luminaire	each	490.13

* Pole line cost to be used = $5.34 / 2 = $2.67

Note: All charges are subject to taxes as provided in Section 3.14.

Jersey Central Power & Light
A FirstEnergy Company

EXHIBIT A

STANDARD MAN-HOUR RATE CALCULATION
2020 NEW JERSEY LINEMEN

Job # 221	Line Construction & Maintenance – Chief "B".............	$ 54.38/ hr
Job # 226	Line Construction & Maintenance – 1st Class..............	$ 52.13/ hr
		$106.51/ hr

Standard Rate per Man-Hour = $106.51 / 2 =.............................. $ 53.26/ man-hr
Line Crew Supervisor .... $ 7.78/ man-hr
Total Rate per Man-hour .... $ 61.04/ man-hr

Total Direct Labor Rate per Man-Hour.................................$ 61.04/man-hr

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Line Construction & Maintenance Rates are based upon actual averages for the current work force in New Jersey. These rates are slightly higher than the labor contract rates because of some personalized rates.

Line Crew Supervisor Rate is derived from JCP&L/FE's "market rate" base wage for this job classification. The "market rate" for this job is $ 129,500/year; based on 2080 hours available for work per year, this rate equals $62.26 per hour. A Line Crew Supervisor is responsible for four two-man crews, so one eighth of this rate is applied per man-hour.

VEHICLE RATES

Line Truck (WKTRK) Includes Class 4, Class 5, and Dump Truck..... $ 27.38/hour

WKTRK Rate per Man-Hour (2 man crew) = 27.38 ÷ 2 ....$ 13.69/man-hr

Jersey Central Power & Light
A FirstEnergy Company

EXHIBIT B

LABOR OVERHEAD RATE- 2020 NEW JERSEY LINEMEN

	LC&M Chief "B"	LC&M
BASE HOURLY WAGES	**$ 54.38**	**$ 52.13**

ACTIVITY LABOR RATES

PENSION SERVICES 27.81%
OPEB SERVICES........................ 2.69%

TOTAL ACTIVITY LABOR RATE 30.50%

BENEFITS & TAXES

FRINGE BENEFITS 26.75%
PAYROLL TAXES 8.80%
INCENTIVE COMPENSATION 6.00%

TOTAL BENEFITS & TAXES 41.55%

TOTAL LABOR OVERHEAD RATE 72.05%

MATERIAL OVERHEAD RATE

STORE HANDLING 68.60%

EXHIBIT C

Jersey Central Power & Light
A FirstEnergy Company

COMPARISON OF UPDATED APPENDIX A TARIFF CHARGES

Type Of Installation	Charges per Building Lot – Average Front Footage per Lot			
	< = 125 Ft	126 – 225 Ft	226 – 325 Ft	> = 326 Ft
Installation with Customer Providing All Trenching				
Non-Refundable Charges per Building Lot				
Current Charges	$317	$370	$424	$743
Revised Charges	$361	$428	$495	$881
Refundable Charges per Building Lot				
Current Charges	$648	$1,296	$1,944	$3,240
Revised Charges	$828	$1,656	$2,484	$4,140

EXHIBIT JC-8

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Thomas Workoff

Re: Meteorological Aspects of the JCP&L Service Territory

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Thomas Workoff. My business address is 341 White Pond Drive, Akron, OH, 44320.

Q. Please identify your employer and describe your current position.

A. I am employed by FirstEnergy Service Company. My responsibilities include weather forecasting, data retrieval and analysis, forensic meteorology, weather research, product development, and computer programming, amongst others. My qualifications and experience are set forth in detail in Appendix A attached to this testimony.

Q. Have you previously testified in Board of Public Utilities ("Board" or "BPU") proceedings?

A. No.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe Jersey Central Power & Light Company's ("JCP&L" or the "Company") service territory and the severe weather events that have impacted the Company's service territory over the period 2016-2019.

Q. Please summarize your testimony.

A. To begin, JCP&L's coastal location makes it more prone to powerful Atlantic coastal storms in the winter. This coastal location also is susceptible to impact from tropical weather systems - namely tropical storms and hurricanes. Additionally, it's mountainous terrain in northwestern New Jersey creates an elevated risk for high winds, locally heavy snow and freezing rain.

Secondly, the JCP&L territory has experienced a run of abnormal and extreme weather conditions over the past four years. Data indicates that periods of extreme annual rainfall and thunderstorm activity, as well as above-normal occurrences of damaging wind gusts, have occurred at various times during the 2016-2019 period.

Thirdly, it is prudent to expect that the abnormal and extreme weather can and will happen again; therefore JCP&L remains susceptible to more of these extreme weather events.

II. SERVICE TERRITORY

Q. Does JCP&L's service territory have any remarkable features that make it more susceptible to experiencing severe weather events?

A. Let me begin by saying that the testimony of Company Witness, Dennis L, Pavagadhi (Exhibit JC-7) provides an overview and discusses the Company's service territory, which I will not repeat here. As to remarkable features, JCP&L's coastal location makes it more prone to powerful Atlantic coastal storms in the winter—this creates an elevated risk for storms featuring strong winds and heavy snow. This coastal location also is susceptible to impact from tropical weather systems—namely tropical storms and hurricanes—which can bring extreme wind, rain and coastal flooding to JCP&L's territory. Additionally, it's mountainous terrain in northwestern New Jersey creates an elevated risk for high winds, locally heavy snow and freezing rain.

Q. Can you be more specific?

A. Yes. The highest elevations in the State are found in northern New Jersey and specifically coincide with the Company's Northern Region, which experiences, on average, approximately twice the annual snowfall and incidents of freezing rain as compared to the rest of New Jersey as indicated in the following figures:

Figure 1

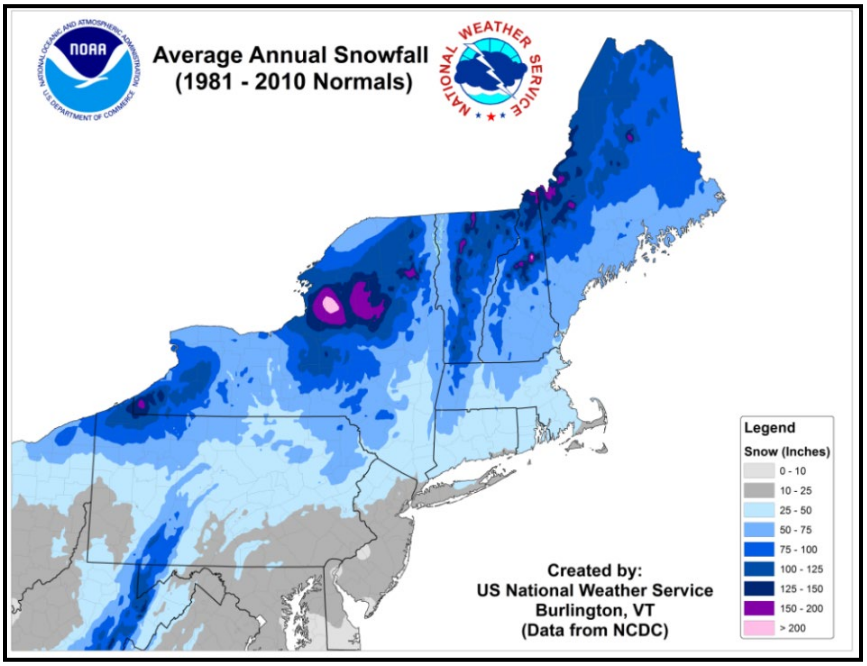
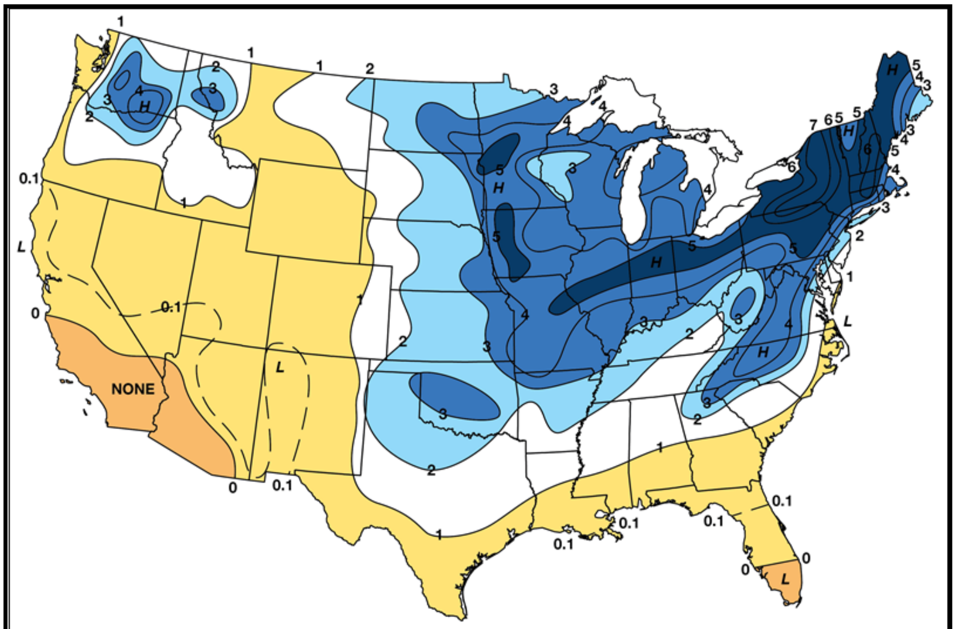


Figure 1[1] above shows that New Jersey's northwest corner (home to part of JCP&L's Northern Region) is prone to average annual snowfalls of at least twice the amount of any other part of the State.

[1] NOAA's National Weather Service, Burlington Forecast Office: https://www.weather.gov/btv/climate.

Figure 2



The average annual number of days with freezing rain, based on 1948-2000 data. *From Changnon and Karl, 2003.*

Figure 2[2] above shows the northwest corner of the State to be the area most affected by freezing rain as compared to the rest of the State. Northern New Jersey averages 3-5 days annually as compared to 1-2 for the rest of the State.

[2] Changnon, S. A., and T. R. Karl, 2003: Temporal and spatial variations of freezing rain in the contiguous United States. *J. Appl. Meteor.*, **42**, 1302–1316.

Figure 3

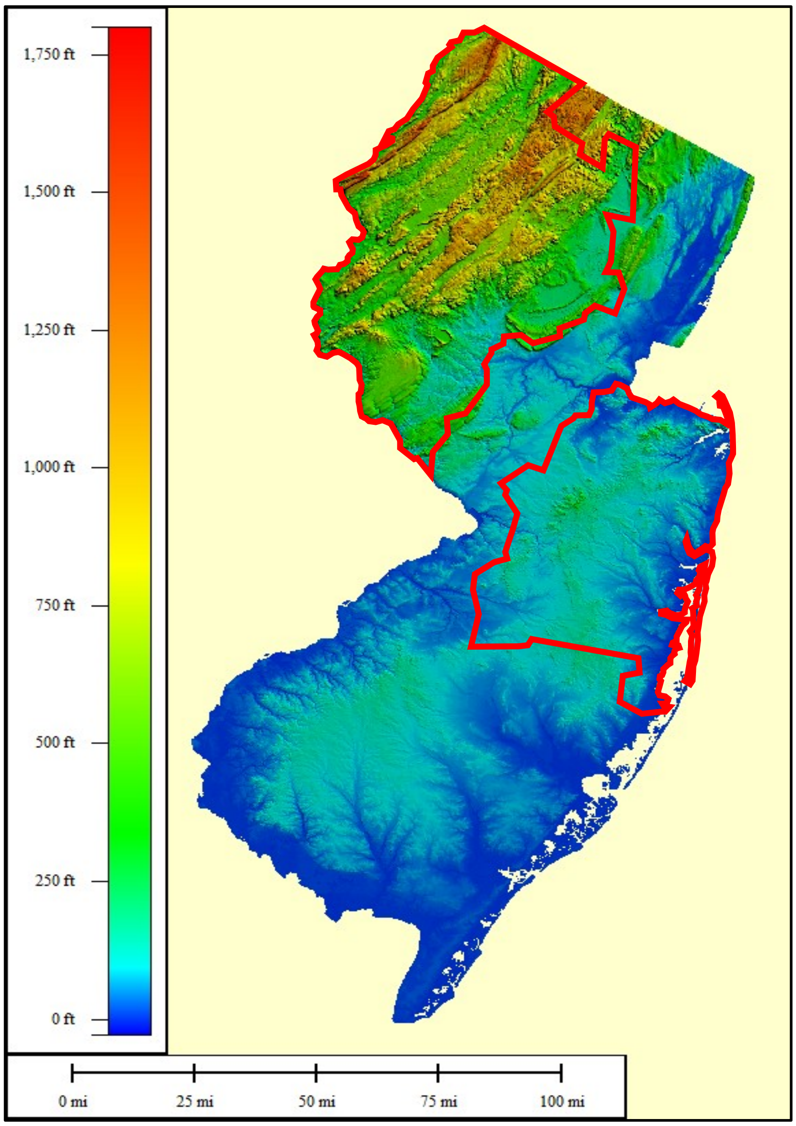

1,750 ft
1,500 ft
1,250 ft
1,000 ft
750 ft
500 ft
250 ft
0 ft
0 mi
25 mi
50 mi
75 mi
100 mi

Figure 3[3] above shows the very distinct elevation differences between northern New Jersey, particularly the northwest corner, as compared to the relatively low levels of the rest of the State.

In addition, in considering the Company's overall topography, I think it is important to recognize the heavily coastal nature of the Company's Central Region service territory, including some of New Jersey's barrier islands. JCP&L's service territory encompasses approximately 80 miles of New Jersey's 130 miles of Atlantic Ocean shoreline,[4] including approximately 20 miles of barrier island coastline. These areas are often the front line of exposure to seasonal coastal storms, including hurricanes and nor'easters, and their high winds, heavy rains, storm surge and concomitant flooding.

III. WEATHER EVENTS

Q. Has JCP&L's service territory experienced extreme or unique weather events over the past four years?

A. Yes. In March of 2018, JCP&L territories were impacted by four consecutive strong coastal storms over a span of just 19 days: Riley on March 2, Quinn on March 7, Skylar on March 12, and Toby on March 21. While strong coastal storms are a common occurrence during the winter the season, the occurrence of four intense cyclones over the same relative geographical area in such a short period of time is a unique set of events.

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[3] National Elevation Data Set from the US Geological Service. Available at: https://topocreator.com/ned-jpg/city_a/600/nj.jpg.

[4] Available at: https://stockton.edu/coastal-research-center/njbpn/geologic-hist.html

Q. In reviewing the past meteorological data for JCP&L's service territory have you noticed any weather-related abnormalities over the past four years that you would like to highlight?

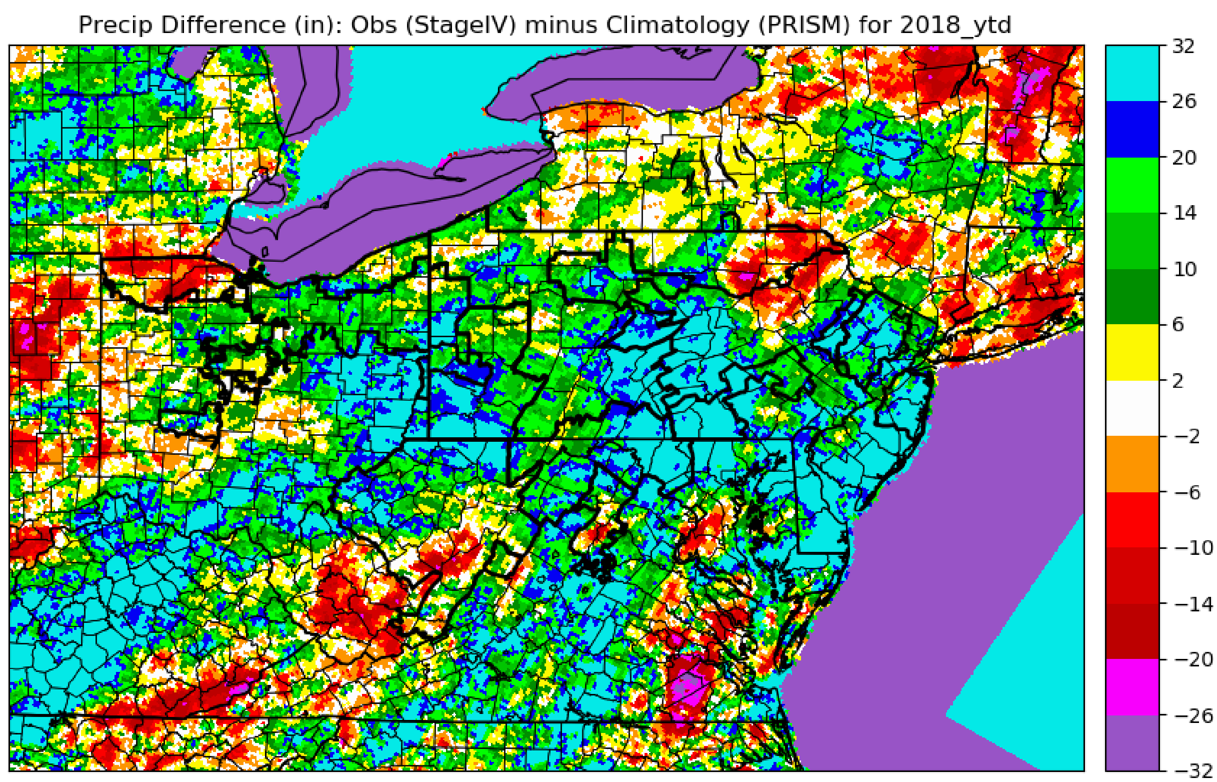
A. Yes. Weather data obtained from National Oceanic and Atmospheric Administration ("NOAA") and Oregon State University--data such as thunderstorm wind damage, days with wind gusts greater than forty mph, and total precipitation--can be reviewed to draw conclusions regarding recent weather patterns in JCP&L. Any of these criteria alone, (as well as ice and wet snow for which the data is not sufficiently available), or a combination of, can have a negative effect on JCP&L's service territory as evidenced during recent major weather events experienced. I note that, as mentioned previously, this conclusion does not address ice and wet snow, which also have significant negative impacts on service, because data available does not provide enough confidence to identify and track such elements with a satisfactory level of certainty.

From this data, we can conclude that the weather in the JCP&L service territory has been abnormally active over the past four years, as measured by different metrics. In fact, JCP&L has experienced extreme weather anomalies twice in the last 2 years alone. 2018 was an extremely wet year for JCP&L territories overall. Using annual precipitation data from NOAA and Oregon State University, Figure 4[5] below shows that many portions of JCP&L received more than 25 inches of precipitation above their normal yearly values. The higher levels of precipitation in 2018, in part, can be attributed to the heavy precipitation and abnormal snow events in March 2019, including Winter Storms Riley,

[5] NOAA Stage IV precipitation data acquired from: https://www.emc.ncep.noaa.gov/mmb/ylin/pcpanl/stage4/. PRISM 30 year (1981-2010) precipitation normals acquired from: http://www.prism.oregonstate.edu/.

Quinn, and Toby during which time upwards of 19 inches of snow impacted JCP&L, causing extensive damage to the Company's infrastructure.

Figure 4



In addition to the extremely wet 2018, in 2019 JCP&L's service territory received an extreme amount of severe thunderstorm activity and associated thunderstorm wind damage. According to NOAA data shown in Table 1A, the number of thunderstorm damage reports—which are used as a proxy to track thunderstorm damage, as thunderstorm wind gusts often occur away from standard meteorological observation stations—in the Company's service territory in 2019 was 261. To put that number in perspective, the average number of yearly damage reports for the 2000-2018 period is 43; the maximum number in the 2000-2018 period was 85, which occurred in 2012. The amount of thunderstorm damage reports in calendar year 2019 was more than three times the amount of any other year in the past two decades, and more than 5 times the 19-year average.

Table 1A

Year	2000-2015 Average	Max	2016	2017	2018	2019
Damage Reports	35	85	63	46	28	261
Damage Days	14.6	20	20	14	11	26

Additionally, JCP&L experienced a period of elevated damaging wind activity during the 2016-2019 timeframe. Table 1B uses NOAA CF6 data to show the amount of calendar days where peak wind gusts exceeded 40 mph at Trenton, NJ and Philadelphia, PA. We use Trenton and Philadelphia for this metric as they are the closest locations to JCP&L territory that have NOAA CF6 data available; CF6 data provide quality controlled daily measurements of peak wind speeds going to back mid-2004.

Table 1B

Year	2005-2015 Average	Max	2016	2017	2018	2019
Trenton	12	18	13	11	10	17
Philadelphia	22	29	30	26	19	28

As can be seen in Table 1B (separating the past four years (2016-2019) to compare to the average 2005-2015 values), three of the past four years have seen an above-average occurrence of days with 40+ mph wind gusts in Philadelphia, with two of the past four years above average in Trenton. 2016 also had the most days with 40+ mph peak winds during this period of record in Philadelphia.

Circling back to thunderstorm damage reports, Table 1A shows that there has been an abnormally high amount of damaging severe thunderstorm activity in JCP&L over the past four years. Three of the four years in the 2016-2019 period saw an above-average amount of wind damage reports, and as previously mentioned, 2019 saw nearly 5 times the average amount of reports. In addition to the number of damage reports, 2016 and 2019 both saw more frequent thunderstorm damage, as evidenced in Table 1A. There were an above-average number of days that featured a damaging wind report (referred to as a 'Damage Day') in the Company's service territory. These metrics provide evidence that JCP&L has seen an anomalous amount of damaging wind events over the 2016-2019 period.

IV. <u>FUTURE IMPACT</u>

Q. Do you have a professional view based on the weather patterns experienced by JCP&L over the past four years and your scientific knowledge regarding the susceptibility of the JCP&L service territory to similar weather events in the future, including with respect to a changing climate?

A. Yes. Because JCP&L has experienced these extreme events, it is prudent to expect they can and will happen again; therefore JCP&L remains susceptible to more of these extreme weather events.

Additionally, it is the consensus of the atmospheric and climate science communities that the climate is changing. Weather and climate are very different phenomena, however, and we do not have the ability, scientifically, to understand the possible impact that a changing climate has or will have on any individual weather events. That said, there is evidence that a changing climate could make extreme weather events—such as heavy precipitation, flooding, heat waves and cold outbreaks—more common.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

Appendix A

WORKOFF, THOMAS E

FirstEnergy Service Company
341 White Pond Drive
Akron, OH 44320
330-436-1475

EDUCATION

University of Illinois Urbana-Champaign
M.S. Atmospheric Science **2010**
Thesis: 'A study of the effect of Lake Erie on deep convective systems'

State University of New York: College at Brockport
B.S. Meteorology **2005**
Minor: Mathematics

PROFESSIONAL EXPERIENCE

FirstEnergy Service Corporation
Senior Scientist **2015-**
Weather forecasting, data retrieval and analysis, forensic meteorology, weather research, product development, computer programming, air quality policy

NOAA National Weather Service/I.M. Systems Group
Testbed Meteorologist **2011-2015**
Design, facilitate and execute weather forecasting research projects, acquire and development meteorological dataset and implement them into operational forecast environment, design and implement forecast training documents and exercises, write and present new research findings.

Midwestern Regional Climate Center
Service Climatologist **2010-2011**
Acquire and analyze meteorological and climate data for clients, conduct research on past hydrometeorological event.

University of Illinois Urbana Champaign
Research Assistant **2008-2010**
Design, execute and assist with meteorological research projects, mainly focusing on the Great Lakes region.

University of Illinois Urbana Champaign
Teaching Assistant **2006-2008**
Design and teach lectures and laboratory exercises for introductory weather classes at the undergraduate level.

WHAM-TV
Meteorologist **2004-2005**
Create and disseminate short and long-term weather forecasts.

RELATED EXPERIENCE

American Meteorological Society
Journal Editor **2010-**

Journal of Applied Meteorology and Climatology; Weather and Forecasting

NOAA Weather Prediction Center
2012-2015
Project Lead
Winter Weather Experiment (2012, 2013, 2014, 2015), Flash Flood and Intense Rainfall Experiment (2013, 2014), Atmospheric River Forecasting Experiment (2012)

American Meteorological Society
Member **2005-**

AMS Board of Private Sector Meteorologists
Member, Mentor **2018-**

PUBLICATIONS AND PAPERS

Workoff, T. E., D. A. R. Kristovich, N. F. Laird, R. LaPlante and Daniel Leins, 2011: Influence of the Lake Erie Over-Lake Boundary Layer on Deep Convective Storm Evolution. *Wea. Forecasting*, **27**, 1279–1289.

Barthold, F. E., T. E. Workoff, B. A. Cosgrove, J. J. Gourley, D. R. Novak, K. M. Mahoney, 2015: Improving Flash Flood Forecasts: The HMT-WPC Flash Flood and Intense Rainfall Experiment. *Bull. Amer. Meteor. Soc*., **96**, 1859-1866.

Moore, B. J., T. M. Hamill, E. M. Sukovich, T. Workoff, and F. E. Barthold, 2015: The utility of the NOAA reforecast dataset for quantitative precipitation forecasting over the coastal western United States. *J. Operational Meteor*., **3**, 133−144.

Baxter, Martin A., G. M. Lackmann, K. M. Mahoney, T. E. Workoff, T. M. Hamill, 2014: Verification of Quantitative Precipitation Reforecasts over the Southeast United States. *Wea. Forecasting*, 29, 1199–1207.

EXHIBIT JC-9

BEFORE THE

NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Joseph Dipre

Re: Capital Structure and Cost of Capital

DIRECT TESTIMONY OF JOSEPH DIPRE,
FIRSTENERGY SERVICE COMPANY, ON BEHALF OF JERSEY CENTRAL POWER & LIGHT COMPANY

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Joseph Dipre. My business address is 76 South Main Street, Akron, OH 44308.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company. My title is Sr. Advisor, Long Term Planning and Corporate Responsibility.

Q. What are your current responsibilities?

A. I am responsible for supporting finance-related activities including budgeting, forecasting, and financial planning. My responsibilities primarily focus on the regulated companies within the FirstEnergy system, including Jersey Central Power & Light Company ("JCP&L" or the "Company").

Q. Have you previously testified in proceedings before the Board of Public Utilities ("Board" or "BPU")?

A. Yes.

Q. Please describe your educational background and professional experience.

A. My educational background, qualifications, and work experience are set forth in Appendix A.

Q. What is the purpose of your direct testimony?

A. My testimony will describe and explain: (1) JCP&L's capital structure; (2) JCP&L's embedded cost of long-term debt; and (3) JCP&L's overall weighted average cost of capital.

Q. **Please summarize your testimony.**

A. I support JCP&L's actual capital structure, with goodwill removed, comprising 52.8% common equity and 47.2% long-term debt. I also support JCP&L's overall embedded long-term debt cost rate of 5.083%, and a weighted average cost of capital of 7.76%.

Q. **Please identify and describe the schedules to your testimony.**

A. I have attached to my testimony four Schedules, identified as follows:

Schedule JD-1 Capital Structures of FirstEnergy Corp. and JCP&L
Schedule JD-2 Recommended Capital Structure for JCP&L
Schedule JD-3 Embedded Cost of JCP&L's Long-Term Debt
Schedule JD-4 JCP&L's Weighted Average Cost of Capital
Schedule JD-5 Financial Credit Ratings

II. CAPITAL STRUCTURE

Q. **Why have you presented the capital structures both for JCP&L and FirstEnergy Corp.?**

A. I have included the capital structures for both FirstEnergy Corp. and JCP&L in Schedule JD-1 because it is a requirement contained in the Stipulation entered into by several parties including JCP&L, the Division of the Ratepayer Advocate (now the Division of Rate Counsel) and Board Staff in connection with the merger between FirstEnergy Corp. and JCP&L's former parent company, GPU, Inc., which was approved in the Board's Order dated October 9, 2001 in Docket No. EM00110870. The relevant provision of the Stipulation states as follows:

> JCP&L further agrees to file, in all future base rate cases, its case using two alternative capital structures. One of the alternatives will be a consolidated capital structure based on the capital structure that is maintained by FirstEnergy (the holding company). The second alternative will be a stand-alone JCP&L capital structure. The parties to future base rate cases will be free to argue for the benefits

of using either capital structure for ratemaking purposes or another alternative.

As I discuss in more detail below, I recommend that JCP&L's capital structure, with goodwill removed from the equity balance, be used in this case, rather than that of FirstEnergy Corp. or another alternative.

Q. Why should JCP&L's capital structure be used in this case?

A. The purpose of this rate proceeding is to determine the appropriate rates for the regulated entity, JCP&L. Those rates should be based on JCP&L's rate base, revenues and expenses, and should provide a fair rate of return that reflects the financial metrics of JCP&L, and not FirstEnergy Corp. FirstEnergy Corp. is a multi-utility holding company that also owns non-regulated businesses and its assets and liabilities, revenues and expenses are not being evaluated in this proceeding, nor is it relevant to make any assessment in this proceeding of FirstEnergy Corp.'s unique risk-return profile, which is separate and distinct from that of JCP&L. In addition, I have been advised that the Board's long-standing practice is to use the utility's own capital structure for rate making purposes, rather than that of its parent.

Q. Please describe what the projected capital structure of JCP&L will be on September 30, 2020.

A. JCP&L's projected capital structure of 31.1% debt and 68.9% equity on September 30, 2020 is shown in Schedule JD-1. Total debt for purposes of the capital structure to be utilized in this proceeding does not include the balances of short-term debt and securitized debt. Short-term borrowings are sources of liquidity and are not utilized to finance long-lived assets, such as those included in JCP&L's rate base.

Furthermore, I have been advised that the Board's practice is to exclude short-term debt from a utility's capital structure in the context of base rate cases. Securitized debt is excluded because the securitization bonds are not recognized as an obligation of JCP&L but have been issued by bankruptcy remote Special Purpose Entities.

Q. **Why are you proposing a capital structure at September 30, 2020, rather than at the end of the test year?**

A. The Board's long-standing practice regarding post-test year adjustments to capital structure is based on its decision in *In re Elizabethtown Water Company*, Dkt. No WR8504330 (Order dated May 23, 1985), at 2 ("*Elizabethtown Water*"). According to the Board's *Elizabethtown Water* precedent, where rate case filings include some historical and some forecast data, utilities are generally permitted to include in base rate requests known and measurable adjustments to the capital structure three months beyond the test year for rate base. In the application of *Elizabethtown Water* in this case, the capital structure at September 30, 2020 only differs from the end of the test year, at June 30, 2020, by the forecasted retained earnings.

Q. **Are you proposing an adjusted JCP&L capital structure?**

A. Yes. JCP&L recognizes that, because of the goodwill in its equity balance, its projected capital structure at 9/30/20 has an equity percentage that is outside the range typically approved for ratemaking purposes in New Jersey. Consistent with the Board's practice in the Company's 2012 and 2016 base rate cases, JCP&L made an adjustment to its equity balance to exclude its goodwill balance.[1] Therefore, JCP&L is proposing to use its actual capital structure as of 9/30/20, adjusted to remove goodwill from the equity balance. This results in a proposed capital structure of 47.2% debt and 52.8% equity, as reflected in Schedule JD-2.

Q. Has JCP&L achieved the target equity ratio the parties agreed to in the Company's 2016 base rate case settlement?

A. Yes, in fact, JCP&L has not only achieved the 45% equity ratio, but has surpassed it. The Company has achieved its current capital structure by the credit-supportive actions that began prior to the 2016 base rate case. The parent company of JCP&L, FirstEnergy Corp., contributed $645 million of equity to JCP&L between 2016 and 2018, allowing JCP&L to redeem $700 million of long-term debt over this period. JCP&L did not pay a dividend to FirstEnergy Corp. during the period of 2014 to 2018. In addition, JCP&L's qualified pension plan received contributions of $222 million since December 2016, thus helping to reduce its unfunded liability. These credit-supportive actions strengthened JCP&L's financial position and resulted in

[1] *See I/M/O the Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith*, BPU Dkt. No. ER 12111052 (Order dated 3/18/15 at p. 72), noting that the Company's capital structure "was impacted by such factors as acquisition premiums causing the equity ratio to be more than is required to maintain the financial integrity of the corporation." *See also I/M/O the Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith,* BPU Dkt. No. ER16040383 (Order dated 12/12/16), adopting a Stipulation of Settlement that states: "Paragraph 20: *The Parties agree that JCP&L will target a capital structure with an equity ratio of 45% (excluding goodwill and mark-to-market adjustments) by 2020."*

positive rating actions by all three credit rating agencies (Moody's, S&P, and Fitch). See Schedule JD-5.

Q. Do you believe that favorable regulatory treatment of storm-related costs contributes to JCP&L's credit ratings and lower debt costs?

A. Yes. The rating agencies observe and consider storm cost recovery in the evaluation of JCP&L's credit profile; especially in light of the severe weather that impacts JCP&L's service territory.

Q. Can you provide examples of comments by the rating agencies that illustrate the importance of favorable storm cost recovery as support for JCP&L's credit ratings?

A. Yes. Moody's has had two positive rating actions for JCP&L following the 2016 Base Rate Case, as reflected in Schedule JD-5. In its March 27, 2018 press release, Moody's made the following comments when it revised JCP&L's outlook to positive from stable:

> *"JCP&L's financial metrics have steadily improved over the last two years and we expect them to be maintained at these higher levels going forward" stated Jairo Chung, Moody's analyst. "The positive outlook considers constructive regulatory developments and rate case outcomes as well as declining debt levels that have contributed to improved cash flow to debt metrics" added Chung.*
>
> *"Also, the settlement included accelerated amortization and recovery of certain 2012 storm costs, a credit positive."*
>
> *"In March 2018, New Jersey experienced three significant winter storms, affecting JCP&L's services and operations. Although we expect some financial impact from the storms, we believe it will not be significant enough to have a material negative impact on JCP&L's long- term creditworthiness. Also, we expect a regulatory support for*

> *storm cost recovery based on the previous regulatory actions by the BPU."*

A year later, Moody's subsequently upgraded the ratings of JCP&L to Baa1 from Baa2 on March 27, 2019 and maintained its positive outlook. In its credit opinion, Moody's repeated its comment on regulatory support for storm cost recovery and provided this additional comment in its "Factors that could lead to an upgrade":

> **"***A rating upgrade could be considered if the financial profile remains strong, such that CFO pre-WC to debt is above 20% on a sustained basis. A rating upgrade could be possible if the regulatory environment in New Jersey becomes more constructive in a way that results in shorter regulatory lag and quicker cost recovery, with more consistent regulatory outcome."*

Q. **Are there any other comments you would like to make with regard to capital structure?**

A. Yes. I believe that it is vital that JCP&L maintains access to the capital markets on favorable terms. Setting a rate of return which is based on a capital structure that warrants solid investment grade ratings is necessary because it allows JCP&L to access the capital markets on favorable terms, to maintain its financial integrity and financial flexibility, and to fund investments in its distribution system that are necessary for safe, proper and adequate service. Customers, in turn, benefit from JCP&L incurring lower debt costs.

III. <u>COST OF CAPITAL</u>

Q. **Please describe the calculation of JCP&L's overall embedded cost of long-term debt.**

A. Schedule JD-3 contains the embedded cost schedules for JCP&L's long-term debt. The long-term debt schedule details each series of debt, the date of issuance, maturity, original amount issued and current amount outstanding. The issuance expenses (column 4) represent legal, underwriting and other miscellaneous costs associated with the issuance. The original amount issued plus any premium or minus any discount, reduced by any issuance expenses, results in the net proceeds. The embedded cost rate (column 7) is calculated by taking the net proceeds at the time of issuance and calculating the internal rate of return based on the coupon and the years to maturity. After the embedded rate is calculated for each individual series, the rates are weighted by taking the embedded rate multiplied by the adjusted amount outstanding (amount outstanding multiplied by the net proceeds ratio) and divided by the total adjusted amount of long-term debt outstanding. The embedded cost (column 8) is the embedded rate multiplied by the adjusted amount outstanding, which is calculated by multiplying the net proceeds ratio by the current amount outstanding. As shown on Schedule JD-3, these calculations produce an overall embedded long-term debt cost rate of 5.083%.

Q. How does the current long-term debt cost rate of 5.083% compare to the long-term debt cost rate approved in the Company's last rate case?

A. The long-term debt cost rate approved by the Board in JCP&L's last base rate case and currently reflected in base rates is 5.732%. The effect of the $250 million retirement in June 2017, the $150 million retirement in June 2018, the $300 million retirement in February 2019, and the $400 million issuance in February 2019 in aggregate result in a decrease of 64.9 basis points in the long-term debt cost rate.

This decrease translates into approximately $9.3 million reduction in annual revenue requirements that directly benefits customers as rates are set in this proceeding.

Q. **Please describe the calculation of the weighted average cost of capital?**

A. I have calculated JCP&L's weighted average cost of capital to be 7.76%. The calculation of the weighted average cost of capital is shown on Schedule JD-4. The calculation weights the cost of common equity and embedded cost of long-term debt by the adjusted ratemaking capitalization ratios. The cost of common equity is supported by the testimony of Dylan D'Ascendis in this filing (Exhibit JC-10). The adjusted ratemaking capitalization ratios are sourced from Schedule JD-2 and have been described earlier in my testimony. The embedded cost of long-term debt is sourced from Schedule JD-3 and has been described earlier in my testimony.

Q. **Does this conclude your direct testimony?**

A. Yes.

Joseph Dipre

PROFESSIONAL AND EDUCATIONAL BACKGROUND

I began my professional career at the Ducato and Kline CPA firm from July 1986 through December 1989, performing various accounting-related roles. My utility industry career began with Centerior Energy Corporation in December 1989 as a Tax Analyst in their Tax Department. In July 2004, I transferred to Centerior's Strategic Planning Department as a Financial Analyst performing similar duties in FirstEnergy's Business Planning Department. After several interim promotions, in October 2005 I was promoted to Manager of Financial Studies and Capital Planning. I have served in various finance-related positions including Sr. Advisor in the Treasury Department for approximately four years before accepting my current position in June 2015.

I am a graduate of the Defiance College with undergraduate degrees in Business/Accounting and Mathematics. I earned my CPA status from the State of Ohio in February 1994.

FirstEnergy Corp.
Capitalization

(in millions)		Pro Forma 9/30/2020	%
Total Equity		7,242	23.1%
Long-term Debt		23,594	75.2%
Securitized Debt		503	1.6%
Short-term Borrowings		39	0.1%
Total Capitalization	$	**31,379**	**100.0%**

JCP&L
Capitalization

(in millions)		Pro Forma 9/30/2020		As Adjusted		Adjusted as of 9/30/2020	%
Short-Term Borrowings		205		(205)		-	0%
						-	0%
Total Equity		3,660				3,660	68.9%
Long-term Debt		1,650				1,650	31.1%
Securitized Debt		13		(13)		-	0%
Total Capitalization	$	**5,528**	$	**(218)**	$	**5,310**	**100.0%**

Schedule JD-2

JCP&L
Capitalization

(in millions)	Adjusted as of 9/30/20	Exclude Goodwill	Adjusted as of 9/30/20	%
Total Equity	3,660	(1,811)	1,849	52.8%
Long-term Debt	1,650		1,650	47.2%
Total Capitalization	**$ 5,310**	**$ (1,811)**	**$ 3,499**	**100.0%**

JCP&L
Computation of Long Term Debt Embedded Cost
9/30/2020

Schedule JD-3

Debt Issue	Date of Issue	Date of Maturity	(1) Original Principal Amount	(2) Amount Outstanding	(3) Premium or (Discount) at Issuance	(4) Issuance Expenses	(5) Net Proceeds (1)+(3)-(4)	(6) Net Proceeds Ratio (5)/(1)	(7) Embedded Rate	(8) Embedded Cost (7)*(9)	(9) Adjusted Amount Outstanding (2)*(6)
6.40% Senior Notes	5/12/2006	5/15/2036	200,000,000	200,000,000	(1,216,000)	2,346,872	196,437,128	98.2186	6.536%	12,839,410	196,437,128
6.15% Uns Notes	5/16/2007	6/1/2037	300,000,000	300,000,000	(3,693,000)	327,220	295,979,780	98.6599	6.249%	18,496,143	295,979,780
4.70% Uns Notes	8/21/2013	4/1/2024	500,000,000	500,000,000	(2,595,000)	4,207,350	493,197,650	98.6395	4.865%	23,994,383	493,197,650
4.30% Senior Notes	8/18/2015	1/15/2026	250,000,000	250,000,000	(800,000)	2,113,488	247,086,512	98.8346	4.441%	10,972,171	247,086,512
4.30% Senior Notes	2/8/2019	1/15/2026	400,000,000	400,000,000	5,884,000	3,018,783	402,865,217	100.7163	4.180%	16,837,972	402,865,217
Sub - Totals				**$ 1,650,000,000**						**$ 83,140,079**	**$ 1,635,566,286**

Weighted Cost (8) / (9)

Weighted Cost of Long-Term Debt **5.083%**

Schedule JD-4

JCP&L
Weighted Average Cost of Capital

	Ratios	Embedded Cost	Weighted Average Cost of Capital
Total Equity	52.8%	10.15%	5.36%
Long-term Debt	47.2%	5.08%	2.40%
Total Capitalization	100.0%		7.76%

Schedule JD-5

Financial Credit Ratings

As of 1/08/20	Corporate Credit Rating			Senior Unsecured			Outlook		
	S&P	Moody's	Fitch	S&P	Moody's	Fitch	S&P	Moody's	Fitch
Jersey Central Power & Light	BBB	Baa1	BBB+	BBB	Baa1	A-	S	P	S

S = Stable
P = Positive
N = Negative

Ratings Actions since 2016 Base Rate Case:

S&P
- 8/06/17 revised ratings Outlook to "stable" from "negative"
- 3/28/18 upgraded Stand-Alone Credit Profile (SACP) to "bbb" from "bbb-"
- 4/23/18 revised ratings Outlook to "positive" from "stable"
- 8/27/18 upgraded Corporate Credit rating and Senior Unsecured rating to "BBB" from "BBB-"; Outlook changed to "stable"

Moody's
- 3/27/18 revised ratings Outlook to "positive" from "stable"
- 3/27/19 upgraded Corporate Credit rating and Senior Unsecured rating to "Baa1" from "Baa2"; maintained "positive" Outlook

Fitch
- 1/06/17 ratings on JCP&L was initiated
- 11/5/18 revised ratings Outlook to "positive" from "stable"
- 4/17/19 upgraded Corporate Credit rating to "BBB" from "BBB-"; upgraded Senior Unsecured rating to "BBB+" from "BBB"; maintained "positive" Outlook
- 11/08/19 upgraded Corporate Credit rating to "BBB+" from "BBB"; upgraded Senior Unsecured rating to "A-" from "BBB+"; Outlook changed to "stable"

EXHIBIT JC-10

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In The Matter of The Verified Petition of Jersey Central Power & Light Company For Review And Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Dylan W. D'Ascendis, CRRA, CVA
Director, ScottMadden, Inc.

Re: Jersey Central Power & Light Company

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I. INTRODUCTION

A. Witness Identification

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, NJ 08054.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Director at ScottMadden, Inc.

B. Background and Qualifications

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I offer expert testimony on behalf of investor-owned utilities on rate of return issues and class cost of service issues. I also assist in preparing rate filings, including, but not limited to, revenue requirements and original cost and lead/lag studies. I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I also hold a Masters of Business Administration from Rutgers University with a concentration in Finance and International Business, which was conferred with high honors. I am a Certified Rate of Return Analyst ("CRRA") and a Certified Valuation Analyst ("CVA"). My full professional qualifications are provided in Attachment A.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present evidence on behalf of Jersey Central Power & Light Company ("JCP&L" or the "Company") and recommend an allowed rate of return on common equity ("ROE") for its New Jersey jurisdictional rate base.

Q. HAVE YOU PREPARED SCHEDULES IN SUPPORT OF YOUR RECOMMENDATION?

A. Yes. I have prepared Schedules DWD-1 through DWD-8, which were prepared by me or under my direction.

Q. WHAT IS YOUR RECOMMENDED ROE FOR JCP&L?

A. I recommend that the New Jersey Board of Public Utilities (the "Board") authorize JCP&L the opportunity to earn an ROE of 10.15% on its jurisdictional rate base. The ratemaking capital structure and cost of long-term debt is sponsored by Company Witness Dipre. The overall rate of return is summarized on page 1 of Schedule DWD-1 and in Table 1 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	47.20%	5.08%	2.40%
Common Equity	52.80%	10.15%	5.36%
Total	100.00%		7.76%

III. SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDED COMMON EQUITY COST RATE.

A. My recommended common equity cost rate of 10.15% is summarized on page 2 of Schedule DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to JCP&L. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be <u>identical</u> in risk to any single company. Consequently, there must be an evaluation of relative risk between the company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from applying several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of a proxy group of 17 electric utilities ("Utility Proxy Group") whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a proxy group of six domestic, non-price regulated companies comparable in total risk to the Utility Proxy Group ("Non-Price Regulated Proxy Group"). The results derived from each are as follows:

<u>Table 2: Summary of Common Equity Cost Rates</u>

Discounted Cash Flow Model	8.26%
Risk Premium Model	9.66%
Capital Asset Pricing Model	8.58%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	<u>10.03%</u>
Indicated Cost of Common Equity Before Adjustments	9.60%
Size Adjustment	0.25%
Credit Risk Adjustment	0.06%
Flotation Cost Adjustment	<u>0.22%</u>
Indicated Cost of Common Equity after Adjustment	<u>10.13%</u>
Recommended Cost of Common Equity	<u>10.15%</u>

[1] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope").
[2] *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922) ("Bluefield").

The indicated common equity cost rate across these models was 9.60% before any Company-specific adjustments, which is the midpoint between the average result generated from my models and the highest model result. I then adjusted the indicated common equity cost rate upward by 0.25% and 0.06% to reflect the Company's smaller relative size and riskier bond rating, as compared to the Utility Proxy Group companies, and by 0.22% for flotation costs. These adjustments resulted in a Company-specific indicated common equity cost rate of 10.13%, which, rounded to 10.15%, is my recommendation.

Q. WHY DID YOU USE THE MIDPOINT BETWEEN YOUR AVERAGE MODEL RESULT AND YOUR HIGHEST MODEL RESULT AS YOUR INDICATED ROE BEFORE ADJUSTMENT?

A. As will be discussed in detail below, factors are currently causing the DCF and CAPM to understate the investor-required return. My recommendation to use the upper end of the range of my results is designed to mitigate that understatement.

IV. GENERAL PRINCIPLES

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATE OF 10.15%?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases. Consequently, marketplace data must be relied on in assessing a common equity cost rate appropriate for ratemaking purposes. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

A. <u>Business Risk</u>

Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks <u>generally</u> faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, emerging technologies including distributed energy resources, the vagaries of weather, and the like, all of which have a direct bearing on earnings. Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. Therefore, it is difficult to specifically and numerically quantify the effect of any individual risk on investors' required return, *i.e.*, the cost of capital. For determining an appropriate return on common equity, the relevant issue is where investors see the subject company as falling within a spectrum of risk. To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. <u>Financial Risk</u>

Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT IN DETERMINING A FAIR RATE OF RETURN.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (*i.e.,* failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (*I.E.*, INVESTMENT RISK)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (*i.e.*, total risk) faced by bond investors.[3] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

Q. DO RATING AGENCIES ACCOUNT FOR COMPANY SIZE IN THEIR BOND RATINGS?

A. No. Neither Standard & Poor's ("S&P") nor Moody's have minimum company size requirements for any given rating level. This means, all else equal, a relative size analysis must be conducted for equity investments in companies with similar bond ratings.

V. <u>JCP&L AND THE UTILITY PROXY GROUP</u>

Q. ARE YOU FAMILIAR WITH JCP&L'S OPERATIONS?

A. Yes. JCP&L serves approximately 1.1 million customers in 13 counties within northern, western, and east central New Jersey. JCP&L is not publicly-traded as they comprise an operating subsidiary of FirstEnergy Corp. ("FE" or the "Parent"), which operates in six states[4] and serves approximately six million customers and is publicly-traded under symbol FE.

Q. IN ITS ORDER IN *IN THE MATTER OF THE BUSINESS COMBINATION OF FIRSTENERGY CORP., PARENT COMPANY OF JERSEY CENTRAL POWER & LIGHT COMPANY, AND ALLEGHENY ENERGY, INC.*, THE BPU

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3 Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, e.g., within the A category, an S&P rating can by at A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, e.g., within the A category, a Moody's rating can be A1, A2 and A3.

4 FirstEnergy Corp., 2018 SEC Form 10-K, at 1, In addition to New Jersey, FE also serves customers in Ohio, Pennsylvania, West Virginia, Maryland, and New York.

DIRECTED THAT JCP&L, IN FUTURE RATE PROCEEDING S, "TO THE EXTENT REASONABLE . . . INCLUDE IN THE 'COMPARABLES' GROUP 'DISTRIBUTION ONLY' UTILITIES OR UTILITIES WITH THE MAJORITY OF THEIR ASSETS UNDER REGULATION, BUT MAY INCLUDE OTHER TYPES OF 'COMPARABLES' AS DEEMED APPROPRIATE BY ITS EXPERT ROE WITNESS." DID YOU MAKE AN ATTEMPT TO INCLUDE "DISTRIBUTION ONLY" UTILITIES IN THE ELECTRIC PROXY GROUP?

A. Yes. The electric and combination electric and gas utility industries are characterized by large holding company corporate structures, with many mergers and acquisitions having occurred since the deregulation of the late 1990s. Hence, most vertically integrated holding companies retained their generation operations in affiliated subsidiaries, separate and distinct from the "distribution only" regulated utility, when they restructured. As a consequence, most of the electric and combination electric and gas holding companies currently have both "distribution only" and "generation only" subsidiaries. Therefore, there are currently too few publicly traded electric or combination electric and gas companies which are "distribution only" meeting my selection criteria, making it impossible to select a proxy group of comparable utilities which are "distribution only."

Since it was not possible to select a group of publicly traded electric or combination electric and gas companies comparable to JCP&L which are entirely "distribution only" companies, I applied the selection criteria described below to choose the Electric Proxy Group.

Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE UTILITY PROXY GROUP.

A. The companies selected for the Utility Proxy Group met the following criteria:

(i) They were included in the Eastern, Central, or Western Electric Utility Group of *Value Line's Standard Edition*;

(ii) They have 70% or greater of fiscal year 2018 total operating income derived from, and 70% or greater of fiscal year 2018 total assets attributable to, regulated electric operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (*i.e.*, one publicly-traded utility merging with or acquiring another);

(iv) They have not cut or omitted their common dividends during the five years ended 2018 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted betas;

(vi) They have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and

(vii) They have *Value Line*, Zacks, or Yahoo! Finance consensus five-year earnings per share ("EPS") growth rate projections.

The following 17 companies met these criteria:

Table 3: Utility Proxy Group Companies

Company Name	Ticker Symbol
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
American Electric Power Co., Inc.	AEP
Avista Corporation	AVA
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Eversource Energy	ES
FirstEnergy Corp.	FE
IDACORP, Inc.	IDA
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Co.	POR
Xcel Energy, Inc.	XEL

VI. COMMON EQUITY COST RATE MODELS

A. Discounted Cash Flow Model

Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; *i.e.*, the total common equity return rate expected by investors.

Q. WHICH VERSION OF THE DCF MODEL DO YOU USE?

A. I use the single-stage constant growth DCF model in my analyses.

Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE CONSTANT GROWTH DCF MODEL.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of December 31, 2019, divided by the average closing market price for the 60 trading days ended December 31, 2019.[5]

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.

A. Because dividends are paid periodically (*e.g.* quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Schedule DWD-2 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

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5 *See*, Column 1, page 1 of Schedule DWD-2.

Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO THE UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF MODEL.

A. Investors with more limited resources than institutional investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.

A. As shown on page 1 of Schedule DWD-2, for the Utility Proxy Group, the mean result of applying the single-stage DCF model is 8.17%, the median result is 8.34%, and the average of the two is 8.26%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF. The DCF results should be viewed with caution, however, as the DCF model is currently understating the investor-required return.

Q. WHY IS THE DCF MODEL UNDERSTATING THE INVESTOR-REQUIRED RETURN AT THIS TIME?

A. Traditional rate base/rate of return regulation, where a market-based common equity cost rate is applied to a book value rate base, presumes that market-to-book ("M/B") ratios are at unity or 1.00. However, that is rarely the case. Morin states:

> The third and perhaps most important reason for caution and skepticism is that application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the market-to-book (M/B) ratio of a given stock exceeds unity. This was particularly relevant in the capital market environment of the 1990s and 2000s where utility stocks were trading at M/B ratios well above unity and have been for nearly two decades. The converse is also true, that is, the DCF model overstates that investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.[6]

As he explains, DCF models assume an M/B ratio of 1.0 and therefore under- or over-states investors' required return when market value exceeds or is less than book value, respectively. It does so because equity investors evaluate and receive their returns on the market value of a utility's common equity, whereas regulators authorize returns on the book value of common equity. This means that the market-based DCF will produce the total annual dollar return expected by

[6] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 434 ("Morin").

investors only when market and book values of common equity are equal, a rare and unlikely situation.

Q. WHY DO MARKET AND BOOK VALUES DIVERGE?

A. Market values can diverge from book values for a myriad of reasons including, but not limited to, EPS and DPS expectations, merger/acquisition expectations, interest rates, etc. As noted by Phillips:

> Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.[7]

In addition, Bonbright states:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, *whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market*. In short, market prices are beyond the control, though not beyond the influence of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it ... would result in harmful, uneconomic shifts in public utility rate levels. (italics added)[8]

Q. CAN THE UNDER- OR OVER-STATEMENT OF INVESTORS' REQUIRED RETURN BY THE DCF MODEL BE DEMONSTRATED MATHEMATICALLY?

A. Yes. Page 2 of Schedule DWD-2 demonstrates how my market-based DCF cost rate of 8.26%, when applied to a book value substantially below market value, will understate investors' required return on market value. As shown, there is no

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7 Charles F. Phillips, The Regulation of Public Utilities, Public Utilities Reports, Inc., 1993, at 395.

8 James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates (Public Utilities Reports, Inc., 1988), at 334.

realistic opportunity to earn the expected market-based rate of return on book value. In Column [A], investors expect an 8.26% return on an average market price of $71.62 for the Utility Proxy Group. Column [B] shows that when the 8.26% return rate is applied to a book value of $32.75,[9] the total annual return opportunity is $2.705. After subtracting dividends of $2.241, the investor only has the opportunity for $0.464 in market appreciation, or 0.65%. The magnitude of the understatement of investors' required return on market value using my 8.26% indicated DCF cost rate is 4.48%, which is calculated by subtracting the market appreciation based on book value of 0.65% from my implied expected growth rate of 5.13%.

Q. HOW DO M/B RATIOS OF THE UTILITY PROXY GROUP COMPARE TO THEIR TEN-YEAR AVERAGE?

A. The M/B ratio of the Utility Proxy Group is currently extraordinarily high compared to its ten-year average. As shown in Chart 1, below, since early 2016, the M/B ratios of the Utility Proxy Group have increased significantly over their ten-year average M/B ratio of approximately 1.65 times, respectively.

[9] Representing a market-to-book ratio of 218.69%.

Chart 1: M/B Ratios of the Utility Proxy Group Compared with Ten-Year Average[10]

The significance of this is that even though the ten-year average M/B ratio has always been different than 1.0x, the current M/B ratio is even further removed from 1.0x, further distorting DCF results.

B. <u>The Risk Premium Model</u>

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed.

10 Source of Information: Bloomberg Financial Services.

According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively), and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. PLEASE EXPLAIN HOW YOU DERIVED YOUR INDICATED COST OF COMMON EQUITY BASED ON THE RPM.

A. To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the Predictive Risk Premium Model ("PRPM") and the second method was a risk premium model using a total market approach. The PRPM estimates the risk-return relationship directly, while the total market approach indirectly derives a risk premium by using known metrics as a proxy for risk.

Q. PLEASE EXPLAIN THE PRPM.

A. The PRPM, published in the *Journal of Regulatory Economics,*[11] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility" or ARCH.[12] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility

[11] Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. "A New Approach for Estimating the Equity Risk Premium for Public Utilities", The Journal of Regulatory Economics (December 2011), 40:261-278.

[12] Autoregressive conditional heteroscedasticity; *See also,* www.nobelprize.org.

of prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (*i.e.*, the variance of historical equity risk premiums).

The inputs to the model are the historical returns on the common shares of each Utility Proxy Group company minus the historical monthly yield on long-term U.S. Treasury securities through December 2019. Using a generalized form of ARCH, known as GARCH, I calculated each Utility Proxy Group company's projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series[13] and a GARCH coefficient[14]. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[15] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 2.70%[16] to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury bond yield is a consensus forecast derived from *Blue Chip*[17]. The mean PRPM indicated common equity cost rate for the Utility Proxy Group is 10.14%, the median is 9.74%, and the average of the two is 9.94%. Consistent with my

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13 Illustrated on Columns 1 and 2, page 2 of Schedule DWD-3.
14 Illustrated on Column 4, page 2 of Schedule DWD-3.
15 Annualized Return = (1 + Monthly Return) ^12 - 1
16 *See,* Column 6, page 2 of Schedule DWD-3.
17 *Blue Chip Financial Forecasts ("Blue Chip")*, December 1, 2019 at page 14 and January 1, 2019 at page 2.

reliance on the average of the median and mean results of the DCF models, I relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 9.94%.

Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: 1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, 2) an equity risk premium based on the S&P Utilities Index, and 3) an equity risk premium based on authorized ROEs for electric utilities.

Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF 4.22% APPLICABLE TO THE UTILITY PROXY GROUP.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the second calendar quarter of 2021, and *Blue Chip's* long-term projections for 2021 to 2025, and 2026 to 2030. As shown on line 1, page 3 of Schedule DWD-3, the average expected yield on Moody's Aaa-rated corporate bonds is 3.68%. To derive an expected yield on Moody's A2-rated public utility bonds, I made an upward adjustment of 0.37%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds, in order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-

rated public utility bond yield.[18] Adding that recent 0.37% spread to the expected Aaa-rated corporate bond yield of 3.68% results in an expected A2-rated public utility bond yield of 4.05%. Since the Utility Proxy Group's average Moody's long-term issuer rating is A3/Baa1, another adjustment to the expected A2 public utility bond is needed to reflect the difference in bond ratings. An upward adjustment of 0.17%, which represents one-half of a recent spread between A2 and Baa2 public utility bond yields, is necessary to make the A2 prospective bond yield applicable to an A3/Baa1 public utility bond.[19] Adding the 0.17% to the 4.05% prospective A2 public utility bond yield results in a 4.22% expected bond yield applicable to the Utility Proxy Group.

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the beta-derived risk premium model are: 1) an expected market equity risk premium over corporate bonds, and 2) the beta coefficient. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 9, page 8 of Schedule DWD-3. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums and a Bloomberg-based equity risk premium. Each of these is described below.

18 As shown on line 2 and explained in note 2, page 3 of Schedule DWD-3.
19 As shown on line 4 and explained in note 3, page 3 of Schedule DWD-3.

Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2019 ("SBBI - 2019")[20] less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2018. Using holding period returns over a very long time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, *i.e.*, a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks was 11.62% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 6.08%.[21] As shown on line 1, page 8 of Schedule DWD-3, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.54%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in SBBI - 2019.[22] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in

[20] SBBI Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2018.
[21] As explained in note 1, page 9 of Schedule DWD-3.
[22] SBBI - 2019, at page 10-22.

estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.

A. To derive the regression-based market equity risk premium of 8.61% shown on line 2, page 8 of Schedule DWD-3, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK PREMIUM.

A. I used the same PRPM approach described above to the PRPM equity risk premium. The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate bonds during the period from January 1928 through December 2019.[23] Using the previously discussed generalized form of ARCH, known as GARCH, the projected equity risk premium is determined using Eviews© statistical software. The resulting PRPM predicted a market equity risk premium of 7.38%.[24]

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* DATA FOR YOUR RPM ANALYSIS.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 8 of Schedule DWD-3. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended January 3, 2020, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line*'s Standard Edition.[25]

The average median expected price appreciation is 48%, which translates to a 10.30% annual appreciation, and, when added to the average of *Value Line's* median expected dividend yields of 2.18%, equates to a forecasted annual total return rate on the market of 12.48%. The forecasted Moody's Aaa-rated corporate bond yield of 3.68% is deducted from the total market return of 12.48%, resulting

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[23] Data from January 1926 to December 2018 is from SBBI - 2019. Data from January 2019 to December 2019 is from Bloomberg.

[24] Shown on line 3, page 8 of Schedule DWD-3.

[25] As explained in detail in note 1, page 2 of Schedule DWD-4.

in an equity risk premium of 8.80%, as shown on line 4, page 8 of Schedule DWD-3.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON THE S&P 500 COMPANIES.

A. Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 14.57%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.68% results in a 10.89% projected equity risk premium.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON BLOOMBERG DATA.

A. Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for capital appreciation, identical to the method described above. The expected total return for the S&P 500 is 13.59%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.68% results in a 9.91% projected equity risk premium.

Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK PREMIUM FOR USE IN YOUR RPM ANALYSIS?

A. I gave equal weight to all six equity risk premiums based on each source - historical, *Value Line*, and Bloomberg - in arriving at an 8.52% equity risk premium.

After calculating the average market equity risk premium of 8.52%, I adjusted it by the beta coefficient to account for the risk of the Utility Proxy Group.

As discussed below, the beta coefficient is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Schedule DWD-4, the average of the mean and median beta coefficient for the Utility Proxy Group is 0.56. Multiplying the 0.56 average beta coefficient by the market equity risk premium of 8.52% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 4.77%.

Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A-RATED PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.56% and monthly Moody's A-rated public utility bond yields of 6.56% from 1928 to 2018 to arrive at an equity risk premium of 4.00%.[26] I then used the same historical data to derive an equity risk premium of 6.22% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly

[26] As shown on line 1, page 12 of Schedule DWD-3.

equity risk premiums from January 1928 to December 2019 to arrive at a PRPM-derived equity risk premium of 3.85% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 10.29% and 8.90% using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 4.05%[27], which resulted in equity risk premiums of 6.24% and 4.85%, respectively. As with the market equity risk premiums, I averaged each risk premium based on each source (*i.e.*, historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 5.03%.

Q. HOW DO YOU DERIVE AN EQUITY RISK PREMIUM OF 5.68% BASED ON AUTHORIZED ROEs FOR ELECTRIC UTILITIES?

A. The equity risk premium of 5.68% shown on line 3, page 7 of Schedule DWD-3 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A-rated public utility bonds. That analysis is shown on page 13 of Schedule DWD-3. Page 13 of Schedule DWD-3 contains the graphical results of a regression analysis of 1,158 rate cases for electric utilities which were fully litigated during the period from January 1, 1980 through December 31, 2019. It shows the implicit equity risk premium relative to the yields on A-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with

[27] Derived on line 3, page 3 of Schedule DWD-3.

financial literature on the subject.[28] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds . Given the expected A-rated utility bond yield of 4.05%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 5.68%, which is shown on line 3, page 7 of Schedule DWD-3.

Q. WHAT IS YOUR CONCLUSION OF AN EQUITY RISK PREMIUM FOR USE IN YOUR TOTAL MARKET APPROACH RPM ANALYSIS?

A. The equity risk premium I apply to the Utility Proxy Group is 5.16%, which is the average of the beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums of 4.77%, 5.03%, and 5.68%, respectively.[29]

Q. WHAT IS THE INDICATED RPM COMMON EQUITY COST RATE BASED ON THE TOTAL MARKET APPROACH?

A. As shown on line 7, page 3 of Schedule DWD-3, I calculated a common equity cost rate of 9.38% for the Utility Proxy Group based on the total market approach RPM.

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE PRPM AND THE TOTAL MARKET APPROACH RPM?

A. As shown on page 1 of Schedule DWD-3, the indicated RPM-derived common equity cost rate is 9.66%, which gives equal weight to the PRPM (9.94%) and the adjusted-market approach results (9.38%).

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[28] *See*, *e.g.*, Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at pages 11 to 12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at pages 33 to 45.

[29] As shown on page 7 of Schedule DWD-4.

C. <u>The Capital Asset Pricing Model</u>

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta coefficient (β). A beta coefficient less than 1.0 indicates lower variability than the market as a whole, while a beta coefficient greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the beta coefficient. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta\,(R_m - R_f)$$

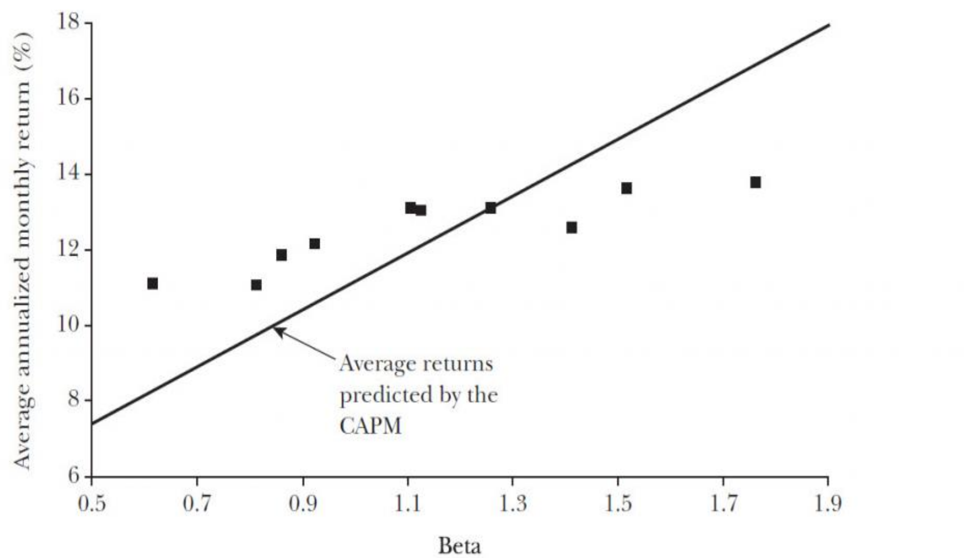
Where:
R_s = Return rate on the common stock
R_f = Risk-free rate of return
R_m = Return rate on the market as a whole
β = Adjusted beta coefficient (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have measured the extent to which security returns and beta coefficients are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the beta coefficient is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[30]

The ECAPM reflects this empirical reality. Fama and French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low." [31]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[32]

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30 Morin, at page 175.

31 Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004 at 33 "Fama & French".

32 Morin, at 175.

* * *

> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,\beta(R_M - R_F) + (1-x)\,\beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$[33]

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[34]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[35]

Clearly, the justification from Morin, Fama, and French along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

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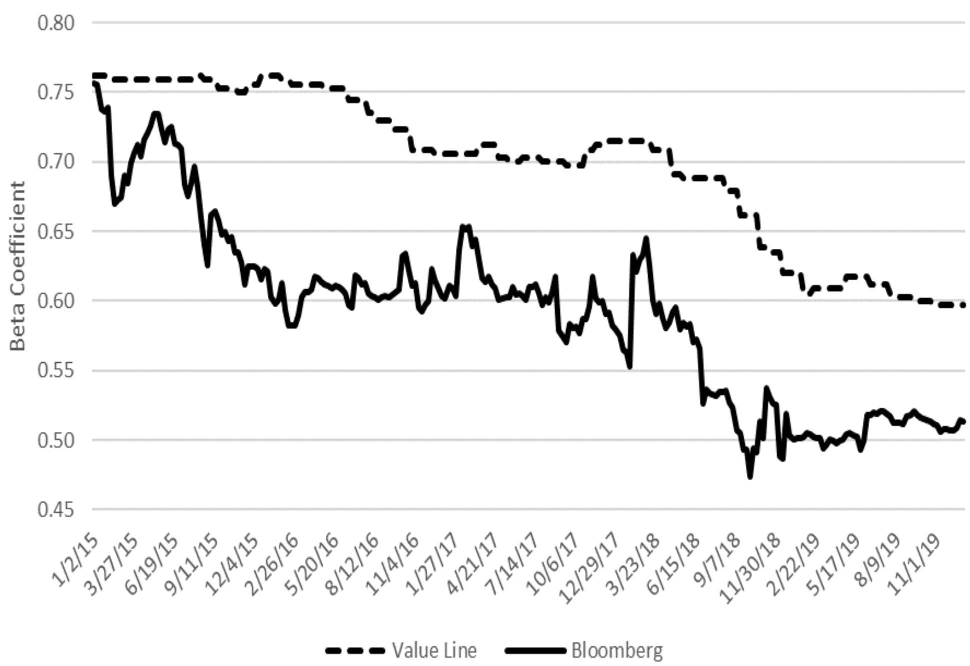
33 Morin, at 190.
34 Fama & French, at 32.
35 *Ibid.,* at 33.

Q. DOES THE RECENT DROP IN BETA COEFFICIENTS FOR THE UTILITY PROXY GROUP EXACERBATE THE UNDERSTATEMENT OF CAPM RESULTS?

A. Yes, it does. As beta coefficients move away from 1.0 (higher or lower) the "area under the curve" between predicted returns using the CAPM and observed returns increases, as shown on Figure 2, above. The beta coefficients for the Utility Proxy Group has steadily declined over the last five years (as shown on Chart 2), moving farther and farther below 1.0, therefore understating the investor-required return as measured by the traditional CAPM.

<u>Chart 2: Value Line and Bloomberg Coefficients for the Utility Proxy Group 2014-Present</u>[36]



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[36] Sources of Information: Value Line Investment Survey, Standard Edition and Bloomberg Professional Services.

Q. WHAT BETA COEFFICIENTS DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the beta coefficients in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg Professional Services. While both of those services adjust their calculated (or "raw") beta coefficients to reflect the tendency of the beta coefficient to regress to the market mean of 1.00, *Value Line* calculates the beta coefficient over a five-year period, while Bloomberg calculates it over a two-year period.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in Column 5, page 1 of Schedule DWD-4, the risk-free rate adopted for both applications of the CAPM is 2.70%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2021, and long-term projections for the years 2021 to 2025 and 2026 to 2030.

Q. WHY IS THE YIELD ON LONG-TERM U.S. TREASURY BONDS APPROPRIATE FOR USE AS THE RISK-FREE RATE?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (*i.e.*, cost of capital) will be applied.

In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSES.

A. The basis of the market risk premium is explained in detail in note 1 on Schedule DWD-4. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums, and one Bloomberg data-based market risk premium.

The long-term income return on U.S. Government securities of 5.12% was deducted from the SBBI - 2019 monthly historical total market return of 11.89%, which results in an historical market equity risk premium of 6.77%.[37] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from SBBI - 2019. That regression analysis yielded a market equity risk premium of 9.63%. The PRPM market equity risk premium is 8.31%, and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through December 2019.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 2.70%, discussed above, from the *Value Line* projected total annual market return of 12.48%, resulting in a forecasted total market equity risk premium of 9.78%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the

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[37] SBBI - 2019, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

projected risk-free rate of 2.70% from the projected total return of the S&P 500 of 14.57%. The resulting market equity risk premium is 11.87%.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 2.70% from the projected total return of the S&P 500 of 13.59%. The resulting market equity risk premium is 10.89%.

These six measures, when averaged, result in an average total market equity risk premium of 9.54%.

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Schedule DWD-4, the mean result of my CAPM/ECAPM analyses is 8.59%, the median is 8.57%, and the average of the two is 8.58%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 8.58%.

D. Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM

Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-PRICE REGULATED COMPANIES?

A. In the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the beta coefficients and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (*i.e.*, five years). These selection criteria resulted in a proxy group of six domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line Investment Survey* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, *i.e.*, not utilities;

(iii) Their beta coefficients must lie within plus or minus two standard deviations of the average unadjusted beta coefficients of the Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted beta coefficients must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Beta coefficients measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar beta coefficients and similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. HAVE YOU PREPARED A SCHEDULE WHICH SHOWS THE DATA FROM WHICH YOU SELECTED THE SIX DOMESTIC, NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. Yes, the basis of my selection and both proxy groups' regression statistics are shown in Schedule DWD-5.

Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, RPM, AND CAPM FOR THE NON-PRICE REGULATED PROXY GROUP?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual non-price regulated companies.

Page 2 of Schedule DWD-6 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group, is 9.38%.

Pages 3 through 5 of Schedule DWD-6 contain the data and calculations that support the 10.82% RPM common equity cost rate. As shown on line 1, page 3 of Schedule DWD-6, the consensus prospective yield on Moody's Baa-rated corporate bonds for the six quarters ending in the second quarter of 2021, and for the years 2021 to 2025 and 2026 to 2030, is 4.60%.[38] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of Baa2, no adjustment to the projected Baa-rated corporate bond yield is necessary.

When the beta-adjusted risk premium of 6.22%[39] relative to the Non-Price Regulated Proxy Group is added to the prospective Baa2-rated corporate bond yield of 4.60%, the indicated RPM common equity cost rate is 10.82%.

Page 6 of Schedule DWD-6 contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 9.99%.

Q. HOW IS THE COST RATE OF COMMON EQUITY BASED ON THE NON-PRICE REGULATED PROXY GROUP COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Schedule DWD-6, the results of the common equity models applied to the Non-Price Regulated Proxy Group -- which group is comparable in total risk to the Utility Proxy Group -- are as follows: 9.38% (DCF), 10.82% (RPM), and 9.99% (CAPM). The average of the mean and median of these models is 10.03%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

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38 *Blue Chip*, December 1, 2019, at page 14 and January 1, 2020, at page 2.

39 Derived on page 5 of Schedule DWD-6.

VII. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENTS

Q. WHAT IS THE INDICATED COMMON EQUITY COST RATE BEFORE ADJUSTMENTS?

A. By applying multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, the indicated cost of common equity before any relative risk adjustments is 9.60%. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

Based on these common equity cost rate results, I conclude that a common equity cost rate of 9.60% is reasonable and appropriate before any adjustments for relative risk differences between JCP&L and the Utility Proxy Group are made. The 9.60% indicated ROE is the approximate midpoint of my average result produced by the application of the models as explained above (9.13%) and my highest model result (10.03%). I have chosen this indicated ROE before adjustment because of current market data which is currently understating the investor-required return for the DCF and traditional CAPM as stated previously.

VIII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

A. Size Adjustment

Q. DOES JCP&L'S SMALLER SIZE RELATIVE TO THE UTILITY PROXY GROUP COMPANIES INCREASE ITS BUSINESS RISK?

A. Yes. JCP&L's smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Duff & Phelps 2019 Valuation Handbook Guide to Cost of Capital - Market Results through 2018 ("D&P - 2019") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," D&P - 2019 states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and

> historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[40]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 14, they note:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[41]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[42] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms**. (emphasis added)[43]

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of

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40 Duff & Phelps 2018 Valuation Handbook Guide to Cost of Capital - Market Results through 2017, Wiley 2018, at 4-1.

41 Fama & French, at 25-43.

42 Brealey, Richard A. and Myers, Stewart C., Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

43 Brigham, Eugene F., Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

return on common equity. Therefore, the Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of JCP&L, including its small relative size, which is justified and supported above by evidence in the financial literature.

Q. IS THERE A WAY TO QUANTIFY A RELATIVE RISK ADJUSTMENT DUE TO JCP&L'S SMALL SIZE WHEN COMPARED TO THE UTILITY PROXY GROUP?

A. Yes. JCP&L has greater relative risk than the average utility in the Utility Proxy Group because of its smaller size, as measured by an estimated market capitalization of common equity for JCP&L.

Table 5: Size as Measured by Market Capitalization for JCP&L's Electric Operations and the Utility Proxy Group

	Market Capitalization* ($ Millions)	Times Greater than The Company
JCP&L	$3,201	
Utility Proxy Group	$17,872	5.6x

*From page 1 of Schedule DWD-7.

JCP&L's estimated market capitalization was $3,201 million as of December 31, 2019, compared with the market capitalization of the average company in the Utility Proxy Group of $17.9 billion as of December 31, 2019. The average company in the Utility Proxy Group has a market capitalization 5.6 times the size of JCP&L's estimated market capitalization.

As a result, it is necessary to upwardly adjust the indicated common equity cost rate of 9.60% to reflect the JCP&L's greater risk due to their smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2018 period. The average size premium for the Utility Proxy Group with a market capitalization of $17.9 billion falls in the 2nd decile, while the Company's estimated market capitalization of $3.2 billion places it in the 5th decile. The size premium spread between the 2nd decile and the 5th decile is 0.76%. Even though a 0.76% upward size adjustment is indicated, I applied a size premium of 0.25% to the Company's indicated common equity cost rate.

Q. SINCE JCP&L IS PART OF A LARGER COMPANY, WHY IS THE SIZE OF THE TOTAL COMPANY NOT MORE APPROPRIATE TO USE WHEN DETERMINING THE SIZE ADJUSTMENT?

A. The return derived in this proceeding will not apply to FE's operations as a whole, but only JCP&L's. FE is the sum of its constituent parts, including those constituent parts' ROEs. Potential investors in the Parent are aware that it is a combination of operations in each state, and that each state's operations experience the operating risks specific to their jurisdiction. The market's expectation of FE's return is commensurate with the realities of the Company's composite operations in each of the states in which it operates.

B. <u>Credit Risk Adjustment</u>

Q. PLEASE DISCUSS YOUR PROPOSED CREDIT RISK ADJUSTMENT.

A. JCP&L's long-term issuer ratings are Baa1 and BBB from Moody's Investors Services and S&P, respectively, which are slightly more risky than the average long-term issuer ratings for the Utility Proxy Group of A3/Baa1 and A-/BBB+, respectively.[44] Hence, an upward credit risk adjustment is necessary to reflect the lower credit rating, *i.e.,* Baa1, of JCP&L relative to the A3/Baa1 average Moody's bond rating of the Utility Proxy Group.[45]

An indication of the magnitude of the necessary upward adjustment to reflect the greater credit risk inherent in a Baa1 bond rating is one-sixth of a recent three-month average spread between Moody's A2 and Baa2-rated public utility bond yields of 0.34%, shown on page 4 of Schedule DWD-3, or 0.06%.[46]

C. <u>Flotation Cost Adjustment</u>

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (*e.g.*, underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED COMMON EQUITY COST RATE?

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

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44 Source of Information: S&P Global Market Intelligence.

45 As shown on page 5 of Schedule DWD-3.

46 0.06% = 0.34% * (1/6).

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit recovery of these costs….
>
> The simple fact of the matter is that common equity capital is not free….[Flotation costs] must be recovered through a rate of return adjustment.[47]

Q. SHOULD FLOTATION COSTS BE RECOGNIZED ONLY IF THERE WAS AN ISSUANCE DURING THE TEST YEAR OR THERE IS AN IMMINENT POST-TEST YEAR ISSUANCE OF ADDITIONAL COMMON STOCK?

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing market price, a small percentage is expensed

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47 Morin, at p. 321.

and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, $0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in investment. Assuming the investor in that stock requires a 10% return on their invested $1.00 (*i.e.*, a return of $0.10), the company needs to earn approximately 10.5% on its invested $0.95 to receive a $0.10 return.

Q. DO THE COMMON EQUITY COST RATE MODELS YOU HAVE USED ALREADY REFLECT INVESTORS' ANTICIPATION OF FLOTATION COSTS?

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[48] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[49] Consequently, it

48 Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at p. 342.

49 Morin, at pp. 327-30.

is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. HOW DID YOU CALCULATE THE FLOTATION COST ALLOWANCE?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing equity that were incurred by FE in its last equity issuance. Based on the issuance costs shown on page 1 of Schedule DWD-8, an adjustment of 0.22% is required to reflect the flotation costs applicable to the Utility Proxy Group.

Q. WHAT IS THE INDICATED COST OF COMMON EQUITY AFTER YOUR COMPANY-SPECIFIC ADJUSTMENTS?

A. Applying the 0.25% size adjustment, the 0.06% credit risk adjustment, and the 0.22% flotation cost adjustment to the indicated cost of common equity of 9.60% results in a Company-specific cost of common equity rate of 10.13%, which rounded to 10.15%, is my recommended common equity cost rate for JCP&L.

IX. CONCLUSION

Q. WHAT IS YOUR RECOMMENDED ROE FOR JCP&L?

A. Given the discussion above and the results from the analyses, I recommend that an ROE of 10.15% is appropriate for the Company at this time.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.15% FAIR AND REASONABLE TO JCP&L AND ITS CUSTOMERS?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). He has served as a consultant for investor-owned and municipal utilities and authorities for 11 years. Dylan has extensive experience in rate of return analyses, class cost of service, rate design, and valuation for regulated public utilities. He has testified as an expert witness in the subjects of rate of return, cost of service, rate design, and valuation before 18 regulatory commissions in the U.S. and an American Arbitration Association panel.

He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured.

Areas of Specialization

- Regulation and Rates
- Utilities
- Mutual Fund Benchmarking
- Capital Market Risk
- Financial Modeling
- Valuation
- Regulatory Strategy
- Rate Case Support
- Rate of Return
- Cost of Service
- Rate Design

Recent Expert Testimony Submission/Appearances

Jurisdiction	***Topic***
Massachusetts Department of Public Utilities	Rate of Return
New Jersey Board of Public Utilities	Rate of Return
Hawaii Public Utilities Commission	Cost of Service, Rate Design
South Carolina Public Service Commission	Return on Common Equity
American Arbitration Association	Valuation

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the City
- Co-authored a valuation report on behalf of a large investor-owned utility company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Recent Publications and Speeches

- Co-Author of: “Decoupling, Risk Impacts and the Cost of Capital”, co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal, March, 2020.
- Co-Author of: “Decoupling Impact and Public Utility Conservation Investment”, co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal, 130 (2019), 311-319.
- “Establishing Alternative Proxy Groups”, before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum, April 4, 2019, New Orleans, LA.
- “Past is Prologue: Future Test Year”, Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit, May 2, 2017, Savannah, GA.
- Co-author of: “Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model”, co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley, The Electricity Journal, May, 2013.
- “Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks”, before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Regulatory Commission of Alaska				
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Arizona Corporation Commission				
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W01445A-18-0164	Rate of Return
Colorado Public Utilities Commission				
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Return on Equity
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Return on Equity
Delaware Public Service Commission				
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Hawaii Public Utilities Commission				
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	8/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy	07/19	Atmos Energy	19-ATMG-525-RTS	Rate of Return
Louisiana Public Service Commission				
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maryland Public Service Commission				
FirstEnergy, Inc.	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	Docket No. 15-75	Rate of Return
Mississippi Public Service Commission				
Atmos Energy	03/19	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Atmos Energy	07/18	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Docket No. SR-2016-0202	Rate of Return
New Jersey Board of Public Utilities				
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
North Carolina Utilities Commission				
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Docket No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
Virginia State Corporation Commission				
WGL Holdings, Inc.	7/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	5/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	7/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design

Table of Contents
to Exhibit JC-10

Jersey Central Power & Light Company
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	47.20%	5.08%	(1)	2.40%
Common Equity	52.80%	10.15%	(2)	5.36%
Total	100.00%			7.76%

Notes:

(1) From Dipre direct testimony.
(2) From page 2 of this Schedule.

Jersey Central Power & Light Company
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Seventeen Electric Companies
1.	Discounted Cash Flow Model (DCF) (1)	8.26%
2.	Risk Premium Model (RPM) (2)	9.66%
3.	Capital Asset Pricing Model (CAPM) (3)	8.58%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	10.03%
5.	Indicated Common Equity Cost Rate before Adjustment for Company-Specific Risk	9.60%
6.	Size Risk Adjustment (5)	0.25%
7.	Credit Risk Adjustment (6)	0.06%
8.	Flotation Cost Adjustment (7)	0.22%
9.	Indicated Common Equity Cost Rate	10.13%
10.	Recommended Common Equity Cost Rate	10.15%

Notes:
(1) From Schedule DWD-2.
(2) From page 1 of Schedule DWD-3.
(3) From page 1 of Schedule DWD-4.
(4) From page 1 of Schedule DWD-6.
(5) Adjustment to reflect the Company's greater business risk due to its smaller size realtive to the Utility Proxy Group as detailed in Mr. D'Ascendis' direct testimony.
(6) Credit risk adjustment to reflect the riskier credit rating of the Company, Baa1, compared to the average credit rating of the Utility Proxy Group, A3/Baa1. The 6 basis point upward adjustment is 1/6 of the current spread between A and Baa rated public utility bond yields as shown on page 4 of Schedule DWD-3.
(7) From Schedule DWD-8.

Jersey Central Power & Light Company
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Seventeen Electric Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Seventeen Electric Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
ALLETE, Inc.	2.85 %	5.00 %	7.20 %	7.00 %	6.40 %	2.94 %	9.34 %
Alliant Energy Corporation	2.67	6.50	5.50	5.40	5.80	2.75	8.55
American Electric Power Co., Inc.	3.03	4.00	5.60	6.05	5.22	3.11	8.33
Avista Corporation	3.26	3.50	3.40	3.50	3.47	3.32	6.79
Duke Energy Corporation	4.14	6.00	4.80	4.40	5.07	4.24	9.31
Edison International	3.62	NMF	5.40	3.90	4.65	3.70	8.35
Entergy Corporation	3.16	2.00	7.00	(1.50)	4.50	3.23	7.73
Eversource Energy	2.58	5.50	5.60	5.45	5.52	2.65	8.17
FirstEnergy Corp.	3.26	6.50	6.00	(6.60)	6.25	3.36	9.61
IDACORP, Inc.	2.52	3.50	3.80	2.50	3.27	2.56	5.83
NorthWestern Corporation	3.20	3.00	2.80	3.23	3.01	3.25	6.26
OGE Energy Corporation	3.60	6.50	4.30	3.50	4.77	3.69	8.46
Otter Tail Corporation	2.70	5.00	7.00	9.00	7.00	2.79	9.79
Pinnacle West Capital Corp.	3.49	5.00	4.90	4.41	4.77	3.57	8.34
PNM Resources, Inc.	2.46	7.00	5.60	6.35	6.32	2.54	8.86
Portland General Electric Co.	2.76	4.50	4.50	4.10	4.37	2.82	7.19
Xcel Energy, Inc.	2.59	5.50	5.40	5.20	5.37	2.66	8.03
						Average	8.17 %
						Median	8.34 %
						Average of Mean and Median	8.26 %

NA= Not Available

Notes:

(1) Indicated dividend at 12/31/2019 divided by the average closing price of the last 60 trading days ending 12/31/2019 for each company.

(2) From pages 3 through 19 of this Schedule.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 5) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for ALLETE, Inc., 2.85% x (1+(1/2 x 6.40%)) = 2.94%.

(5) Column 5 + column 6.

Source of Information:

Value Line Investment Survey
www.zacks.com Downloaded on 12/31/2019
www.yahoo.com Downloaded on 12/31/2019

Jersey Central Power & Light Company
Demonstration of the Inadequacy of a DCF Return Rate Related to Book Value When Market Value is Greater than Book Value

		[A]	[B]
		Based on the Proxy Group of Seventten Electric Companies	
Line No.		Market Value	Book Value
1.	Per Share	$ 71.62 (1)	$ 32.75 (2)
2.	DCF Cost Rate (3)	8.26%	8.26%
3.	Return in Dollars (4)	$ 5.916	$ 2.705
4.	Dividends (5)	$ 2.241	$ 2.241
5.	Growth in Dollars (6)	$ 3.675	$ 0.464
6.	Return on Market Value (7)	8.26%	3.78%
7.	Rate of Growth on Market Value (8)	5.13%	0.65%

Notes:
(1) Average market price for each proxy company.
(2) Average book value of the Proxy Group of Seventeen Electric Companies as shown of Schedule DWD-7, page 2.
(3) Indicated DCF cost rate as shown on page 1 of this Schedule.
(4) Line 1 x Line 2.
(5) Dividends are based on the average adjusted dividend yield as shown on page 1 of this Schedule.
(6) Line 3 - Line 4.
(7) Line 3 / Line 1.
(8) Line 5 / Line 1.

ALLETE NYSE-ALE

RECENT PRICE **80.04** | P/E RATIO **23.7** (Trailing: 22.1; Median: 17.0) | RELATIVE P/E RATIO **1.37** | DIV'D YLD **3.1%** | VALUE LINE

TIMELINESS 3 Lowered 4/5/19
SAFETY 2 New 10/1/04
TECHNICAL 1 Raised 11/22/19
BETA .65 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$71-$102	$87 (10%)

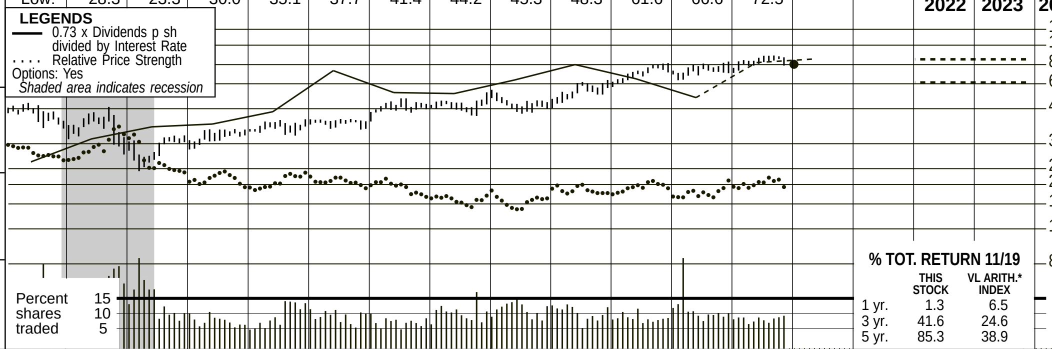
2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+5%)	*5%*
Low	65	(-20%)	*-1%*

Institutional Decisions

	1Q2019	2Q2019	3Q2019
to Buy	143	145	125
to Sell	119	126	142
Hld's(000)	37042	37472	38347

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7	66.9	81.2	82.8	88.6
Low:	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3	48.3	61.6	66.6	72.5



% TOT. RETURN 11/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.3	6.5
3 yr.	41.6	24.6
5 yr.	85.3	38.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
- -	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78	29.10	***23.85***	***23.95***	Revenues per sh	***26.50***
- -	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59	7.37	***7.35***	***7.60***	"Cash Flow" per sh	***8.75***
- -	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13	3.38	***3.30***	***3.45***	Earnings per sh A	***4.25***
- -	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	2.14	2.24	***2.35***	***2.46***	Div'd Decl'd per sh B ■ †	***2.85***
- -	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08	6.07	***12.25***	***13.10***	Cap'l Spending per sh	***6.00***
- -	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	40.47	41.86	***42.90***	***44.05***	Book Value per sh C	***48.25***
- -	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10	51.50	***51.75***	***52.00***	Common Shs Outst'g D	***52.75***
- -	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	23.0	22.2	*Bold figures are*		Avg Ann'l P/E Ratio	***17.5***
- -	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.16	1.19	*Value Line*		Relative P/E Ratio	***.95***
- -	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	3.0%	3.0%	*estimates*		Avg Ann'l Div'd Yield	***3.8%***

CAPITAL STRUCTURE as of 9/30/19
Total Debt $1617.6 mill. **Due in 5 Yrs** $404.3 mill.
LT Debt $1404.9 mill. **LT Interest** $59.0 mill.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $9.9 mill.

Pension Assets-12/18 $598.0 mill. **Oblig** $747.0 mill.

Pfd Stock None

Common Stock 51,668,047 shs.

MARKET CAP: $4.1 billion (Mid Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
759.1	907.0	928.2	961.2	1018.4	1136.8	1486.4	1339.7	1419.3	1498.6	***1235***	***1245***	Revenues ($mill)	***1400***
61.0	75.3	93.8	97.1	104.7	124.8	163.4	155.3	159.2	174.1	***170***	***180***	Net Profit ($mill)	***225***
33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	NMF	***NMF***	***Nil***	Income Tax Rate	***Nil***
12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	2.0%	1.4%	.8%	.7%	***2.0%***	***2.0%***	AFUDC % to Net Profit	***1.0%***
42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	46.3%	42.0%	41.0%	39.9%	***41.0%***	***44.5%***	Long-Term Debt Ratio	***42.0%***
57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	60.1%	***59.0%***	***55.5%***	Common Equity Ratio	***58.0%***
1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	3584.3	***3775***	***4145***	Total Capital ($mill)	***4400***
1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	3904.4	***4330***	***4795***	Net Plant ($mill)	***5050***
4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	5.8%	***5.5%***	***5.0%***	Return on Total Cap'l	***6.0%***
6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	***7.5%***	***8.0%***	Return on Shr. Equity	***9.0%***
6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	***7.5%***	***8.0%***	Return on Com Equity E	***9.0%***
.5%	1.5%	2.9%	2.3%	2.2%	2.5%	3.6%	2.8%	2.4%	2.7%	***2.5%***	***2.5%***	Retained to Com Eq	***3.0%***
93%	81%	66%	71%	72%	67%	60%	66%	68%	66%	***71%***	***71%***	All Div'ds to Net Prof	***66%***

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-2.3	+8.4	-.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	1520	1599	1589
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	318	339	296

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	1.0%	2.5%	*-1.0%*
"Cash Flow"	5.0%	6.5%	*4.0%*
Earnings	1.0%	4.0%	*5.0%*
Dividends	3.0%	3.0%	*5.0%*
Book Value	5.5%	5.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2016	333.8	314.8	349.6	341.5	1339.7
2017	365.6	353.3	362.5	337.9	1419.3
2018	358.2	344.1	348.0	448.3	1498.6
2019	357.2	290.4	288.3	***299.1***	***1235***
2020	***335***	***300***	***300***	***300***	***1245***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2016	.93	.50	.81	.90	3.14
2017	.97	.72	.88	.56	3.13
2018	.99	.61	.59	1.19	3.38
2019	1.18	.64	.60	***.88***	***3.30***
2020	***1.25***	***.65***	***.65***	***.90***	***3.45***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.505	.505	.505	.505	2.02
2016	.52	.52	.52	.52	2.08
2017	.535	.535	.535	.535	2.14
2018	.56	.56	.56	.56	2.24
2019	.5875	.5875	.5875	.5875	

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 16% other, 16%. ALLETE Clean Energy (ACE) owns renewable energy projects. Acq'd U.S. Water Services 2/15; sold it 3/19. Generating sources: coal & lignite, 43%; wind, 10%; other, 4%; purchased, 43%. Fuel costs: 27% of revs. '18 deprec. rate: 3.6%. Has 1,900 employees. Chairman & CEO: Alan R. Hodnik. President: Bethany M. Owen. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's primary utility subsidiary has filed a general rate case. Minnesota Power filed for an increase of $65.9 million, based on a return of 10.05% on a common-equity ratio of 53.81%. The utility is seeking an interim hike of $48 million (subject to refund) at the start of 2020. Currently, Minnesota Power is earning an ROE of 9%. Final rates will be implemented in late 2021.

We now think earnings will decline in 2019. The fourth-quarter comparison is tough because ALLETE Clean Energy (ACE) recorded a gain of $0.20 a share a year ago on the sale of a wind facility. We *included* this in our earnings presentation because ACE has done this before. On the other hand, we *excluded* as a nonrecurring item of $0.22-a-share that ALLETE booked in the first six months of 2019 on the sale of its former subsidiary, U.S. Water Services. This is why our share-profit estimate of $3.30 is below management's targeted range of $3.50-$3.80.

ACE plans to add two or three wind projects annually. Two projects, totaling 186 megawatts, are on track for completion by year-end 2019. This will contribute to ALLETE's earnings growth in 2020. A 303-mw facility should be completed in late 2020. This is expected to bring ALLETE's total investment to over $700 million by then. ACE is also repowering some existing projects, which also boosts its earning power. At some point, ACE might well become large enough for ALLETE to spin it off as an independent company.

The utility is building a transmission project. Minnesota Power earns a current return on this spending. Its investment is estimated at $325 million.

We expect a dividend increase in early 2020. This is the usual timing of dividend hikes by the company's board of directors. We estimate a raise of $0.11 a share (4.7%) in the annual payout, the same increase as in 2019.

The dividend yield is approximately equal to the utility average. For the 18-month period, total return potential is modest. However, like most utility issues, the recent quotation is well within our 2022-2024 Target Price Range. Accordingly, total return prospects over the 3- to 5-year period are negligible.

Paul E. Debbas, CFA *December 13, 2019*

(A) Diluted EPS. Excl. nonrec. gains (losses): '04, (25¢); '05, ($1.84); '15, (46¢); '17, 25¢; '19, 22¢; gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢). '16 & '18 EPS don't sum due to rounding. Next earnings report due early Feb. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred charges. In '18: $11.90/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate allowed in MN on com. eq. in '18: 9.25%; earned on avg. com. eq., '18: 8.2%. Regulatory Climate: Avg.

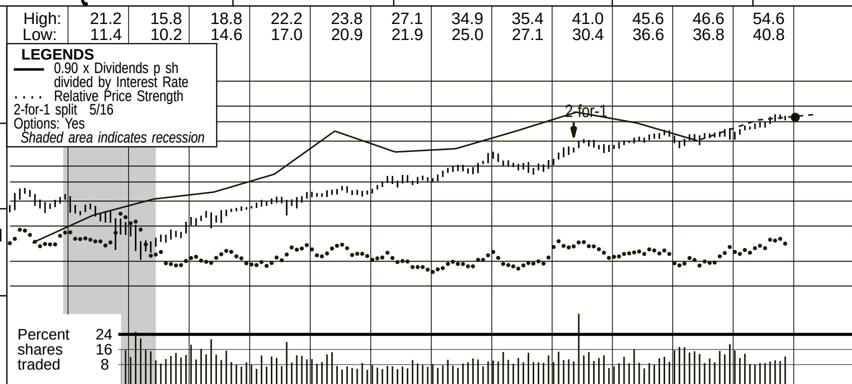
Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	85

ALLIANT ENERGY NDQ-LNT

RECENT PRICE **52.70** | P/E RATIO **22.0** (Trailing: 23.5 / Median: 16.0) | RELATIVE P/E RATIO **1.27** | DIV'D YLD **2.7%** | VALUE LINE

TIMELINESS 2 Raised 11/29/19
SAFETY 2 Raised 9/28/07
TECHNICAL 2 Lowered 11/29/19
BETA .60 (1.00 = Market)

High:	21.2	15.8	18.8	22.2	23.8	27.1	34.9	35.4	41.0	45.6	46.6	54.6
Low:	11.4	10.2	14.6	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8	40.8



Target Price Range 2022 | 2023 | 2024

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$46-$63	$55 (5%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(-5%)	2%
Low	35	(-35%)	-6%

Institutional Decisions

	1Q2019	2Q2019	3Q2019
to Buy	225	242	248
to Sell	240	220	233
Hld's(000)	182908	185336	185069

% TOT. RETURN 11/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.3	6.5
3 yr.	61.9	24.6
5 yr.	98.1	38.9

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	*15.40*	*15.90*	Revenues per sh	*16.45*
2.10	2.60	2.75	2.95	3.34	3.44	3.45	3.45	3.97	4.32	*4.60*	*4.75*	"Cash Flow" per sh	*5.25*
.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	*2.30*	*2.40*	Earnings per sh A	*2.80*
.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	*1.42*	*1.52*	Div'd Decl'd per sh B ■ †	*1.74*
5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.64	*6.35*	*5.90*	Cap'l Spending per sh	*6.15*
12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	19.43	*21.80*	*23.05*	Book Value per sh C	*27.55*
221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	*240.00*	*242.00*	Common Shs Outst'g D	*250.00*
13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03			Relative P/E Ratio	*.85*
5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%			Avg Ann'l Div'd Yield	*4.1%*
3432.8	3416.1	3665.3	3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	3534.5	*3700*	*3850*	Revenues ($mill)	*4115*
208.6	303.9	304.4	337.8	382.1	385.5	380.7	373.8	455.9	512.1	*545*	*575*	Net Profit ($mill)	*695*
- -	30.1%	19.0%	21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	8.4%	*11.0%*	*11.0%*	Income Tax Rate	*11.0%*
- -	- -	- -	- -	- -	- -	6.5%	7.0%	7.6%	7.8%	*7.5%*	*7.5%*	AFUDC % to Net Profit	*7.5%*
44.3%	46.3%	45.7%	48.4%	46.1%	49.7%	48.6%	52.8%	49.0%	53.3%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*52.0%*
51.2%	49.5%	50.9%	48.4%	50.8%	47.5%	51.4%	47.2%	48.6%	46.7%	*48.0%*	*48.0%*	Common Equity Ratio	*48.0%*
5423.0	5840.8	5921.2	6476.6	6461.0	7257.2	7246.3	8177.6	8192.8	9832.0	*10000*	*10500*	Total Capital ($mill)	*12000*
6203.0	6730.6	7037.1	7838.0	7147.3	6442.0	8970.2	9809.9	10798	12462	*13000*	*14000*	Net Plant ($mill)	*17000*
5.1%	6.6%	6.4%	6.3%	7.0%	6.3%	6.3%	5.6%	6.8%	5.2%	*4.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
6.9%	9.7%	9.5%	10.1%	11.0%	10.6%	10.2%	9.7%	10.9%	11.2%	*10.5%*	*10.5%*	Return on Shr. Equity	*10.0%*
6.8%	9.9%	9.5%	10.3%	11.3%	10.9%	10.2%	9.7%	10.9%	11.2%	*10.5%*	*10.5%*	Return on Com Equity E	*10.0%*
.9%	3.8%	3.3%	3.9%	4.9%	4.3%	3.6%	2.8%	4.0%	4.3%	*3.5%*	*4.0%*	Retained to Com Eq	*4.0%*
88%	64%	67%	64%	57%	59%	65%	72%	63%	61%	*62%*	*63%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 9/30/19
Total Debt $6541.5 mill. **Due in 5 Yrs** $1000.0 mill.
LT Debt $5535.1 mill. **LT Interest** $230.0 mill.
(LT interest earned: 3.2x)

Pension Assets-12/18 $808.6 mill. **Oblig.** $1175.0 mill.
Pfd Stock $400.0 mill. **Pfd Div'd** $10.2 mill.
16,000,000 shs.

Common Stock 240,342,949 shs.

MARKET CAP: $12.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+2.0	-1.0	+2.0
Avg. Indust. Use (MWH)	11987	12102	12340
Avg. Indust. Revs. per KWH (¢)	7.04	7.16	7.25
Capacity at Peak (Mw)	5615	5375	5459
Peak Load, Summer (Mw)	5615	5375	5459
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+.4	+.4

Fixed Charge Cov. (%)	295	319	322

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-.5%	-1.0%	*2.0%*
"Cash Flow"	3.0%	4.0%	*6.0%*
Earnings	4.5%	4.5%	*6.5%*
Dividends	7.5%	7.0%	*5.5%*
Book Value	4.0%	4.5%	*7.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	843.8	754.2	925.0	797.0	3320.0
2017	853.9	765.3	906.9	856.1	3382.2
2018	916.3	816.1	928.6	873.5	3534.5
2019	987.2	790.2	990.2	*932.4*	*3700*
2020	*975*	*880*	*1050*	*945*	*3850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.43	.37	.57	.28	1.65
2017	.44	.41	.73	.41	1.99
2018	.52	.43	.87	.37	2.19
2019	.53	.40	.94	*.43*	*2.30*
2020	*.57*	*.46*	*.94*	*.43*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.275	.275	.275	.275	1.10
2016	.295	.295	.295	.295	1.18
2017	.315	.315	.315	.315	1.26
2018	.335	.335	.335	.335	1.34
2019	.355	.355	.355	.355	

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 41%; IA, 58%; MN, 1%. Elect. rev.: residential, 37%; commercial, 25%; industrial, 26%; wholesale, 5%; other, 7%. Fuel sources, 2018: coal, 37%; gas, 30%; other, 33%. Fuel costs: 45% of revs. 2018 depreciation rate: 5.9%. Estimated plant age: 16 years. Has approximately 3,885 employees. Chairman & Chief Executive Officer: John O. Larsen. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy raised its 2019 earnings outlook. The utility boosted the midpoint of its guidance by $0.06 a share, to a range of $2.27-$2.33, primarily due to higher earnings from temperature impacts on retail electric and gas sales during the third quarter. In response, we have boosted our 12-month estimate by a nickel (now at $2.30), representing year-over-year growth of about 5% over 2018's tally.
The company provided 2020 earnings guidance for the first time. Alliant expects share net to be between $2.34 and $2.48 next year. Growth will be driven by investments in the core utility business, including Wisconsin Power and Light's West Riverside Energy Center (the project is about 95% complete) and Interstate Power and Light's wind expansion program. These investments were reflected in WPL's approved electric rates for 2020 and IPL's electric rate review settlement (discussed below), which remains subject to a final decision by the Iowa Utilities Board.
The board of directors raised the dividend in November. This has been the pattern in recent years. The increase was $0.025 a share (7%) quarterly, slightly more than what we had been expecting. Alliant is targeting a payout ratio in a range of 60%-70%.
Leadership unveiled a new five-year investment forecast. Capital expenditures over the 2019-2023 period are expected to be $6.7 billion, with the majority of that earmarked for upgrades to electric and gas distribution systems. Alliant is also accelerating spending on renewables, with a goal to have at least 1,000 mw of solar energy generation by 2023.
The company reached a settlement with the Iowa Utilities Board. Under the proposed terms, annual retail electric rates would increase by $127 million in 2020 for the company's Interstate Power and Light subsidiary. The return on equity would be 9.5%, and the common-equity ratio would be 51%.
This stock is now ranked 2 (Above Average) for year-ahead price performance, having slipped a notch on our Timeliness scale since September. The dividend yield is below average for a utility, and the stock is trading above our 3- to 5-year Target Price Range.
Daniel Henigson, CFA December 13, 2019

(A) Diluted EPS. Excl. nonrecur. gains (losses): '09, (44¢); '10, (8¢); '11, (1¢); '12, (8¢). Next earnings rpt. due mid-Feb. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred chgs. In '18: $89.7 mill., $0.38/sh. (D) In millions, adjusted for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '18: 10.0%; in WI in '18 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	90

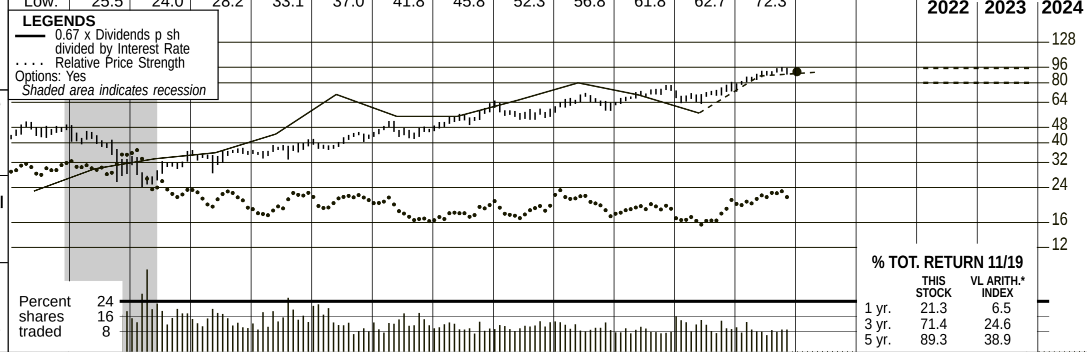
AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE **90.88** | P/E RATIO **21.8** (Trailing: 21.0; Median: 15.0) | RELATIVE P/E RATIO **1.26** | DIV'D YLD **3.1%** | VALUE LINE

TIMELINESS 3 Lowered 9/6/19
SAFETY 1 Raised 3/17/17
TECHNICAL 2 Lowered 12/13/19
BETA .55 (1.00 = Market)

High:	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4	71.3	78.1	81.1	96.2
Low:	25.5	24.0	28.2	33.1	37.0	41.8	45.8	52.3	56.8	61.8	62.7	72.3

LEGENDS
— 0.67 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$79-$104	$92 (0%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+5%)	*4%*
Low	80	(-10%)	*1%*

Institutional Decisions

	1Q2019	2Q2019	3Q2019
to Buy	503	465	482
to Sell	440	463	454
Hld's(000)	363123	367922	368289

% TOT. RETURN 11/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.3	6.5
3 yr.	71.4	24.6
5 yr.	89.3	38.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	*31.95*	*32.85*	Revenues per sh	*34.00*
5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	*9.40*	*9.90*	"Cash Flow" per sh	*11.00*
2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	3.90	*4.15*	*4.40*	Earnings per sh A	*5.00*
1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	*2.71*	*2.84*	Div'd Decl'd per sh B ■	*3.35*
3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	*13.75*	*13.25*	Cap'l Spending per sh	*12.50*
19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	*40.10*	*41.75*	Book Value per sh C	*48.50*
395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	*494.65*	*496.00*	Common Shs Outst'g D	*525.00*
10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97			Relative P/E Ratio	*.95*
6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%			Avg Ann'l Div'd Yield	*3.8%*
						13489	14427	15116	14945	15357	17020	16453	16380	15425	16196	*15800*	*16300*	Revenues ($mill)	*17800*
						1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	*2055*	*2175*	Net Profit ($mill)	*2650*
						29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	5.8%	*2.0%*	*2.0%*	Income Tax Rate	*2.0%*
						10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	10.7%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*9.0%*
						54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	*56.0%*	*56.0%*	Long-Term Debt Ratio	*53.5%*
						45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	*44.0%*	*44.0%*	Common Equity Ratio	*46.5%*
						28958	29184	29747	30823	32913	33001	35633	34775	37707	40677	*44925*	*47075*	Total Capital ($mill)	*54600*
						34344	35674	36971	38763	40997	44117	46133	45639	50262	55099	*59300*	*63125*	Net Plant ($mill)	*73700*
						6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
						10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	*10.5%*	*10.5%*	Return on Shr. Equity	*10.5%*
						10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	*10.5%*	*10.5%*	Return on Com Equity E	*10.5%*
						4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
						56%	66%	60%	63%	62%	61%	60%	54%	67%	65%	*67%*	*67%*	All Div'ds to Net Prof	*68%*

CAPITAL STRUCTURE as of 9/30/19
Total Debt $28391 mill. **Due in 5 Yrs** $9246 mill.
LT Debt $24554 mill. **LT Interest** $1056 mill.
Incl. $918 mill. securitized bonds. Incl. $289 mill. capitalized leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $259.6 mill.
Pension Assets-12/18 $4695.9 mill.
Oblig $4810.3 mill.
Pfd Stock None

Common Stock 493,951,812 shs.
as of 10/24/19
MARKET CAP: $45 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+.3	-1.6	+3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	374	354	254

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-.5%	1.0%	*1.0%*
"Cash Flow"	2.0%	4.0%	*4.5%*
Earnings	3.0%	5.0%	*4.0%*
Dividends	4.5%	5.0%	*5.5%*
Book Value	4.0%	3.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	4045	3893	4652	3790	16380
2017	3933	3577	4105	3810	15425
2018	4048	4013	4333	3801	16196
2019	4057	3573	4315	*3855*	*15800*
2020	*4200*	*3800*	*4400*	*3900*	*16300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.02	1.03	1.43	.76	4.23
2017	.94	.76	1.11	.81	3.62
2018	.92	1.07	1.17	.74	3.90
2019	1.16	.93	1.49	*.57*	*4.15*
2020	*1.10*	*1.00*	*1.50*	*.80*	*4.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.53	.53	.53	.56	2.15
2016	.56	.56	.56	.59	2.27
2017	.59	.59	.59	.62	2.39
2018	.62	.62	.62	.67	2.53
2019	.67	.67	.67	.70	

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.4 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 41%; commercial, 24%; industrial, 19%; wholesale, 8%; other, 8%. Sold Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 36% of revenues. '18 reported depreciation rates (utility): 1.6%-9.8%. Has 17,600 employees. Chairman, President & CEO: Nicholas K. Akins. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power is proposing a sizable wind project. In 2018, AEP canceled a proposed project, which would have seen the company spend $4.5 billion to add 2,000 megawatts, after it failed to win regulatory approval. The current proposal, which would see AEP spend $2 billion for 1,485 mw, has been received more favorably, so far. Public Service of Oklahoma is trying to reach a settlement with the state commission, and SWEPCO is seeking approval from the regulators in Arkansas, Louisiana, and Texas. AEP hopes to obtain all approvals by July. If the project is built, this is expected to add about $100 million to net income in 2022, the first full year of operation.

Four rate cases are pending, and two more are upcoming. AEP Texas filed for a $35 million increase, based on a 10.5% return on equity. However, an administrative law judge recommended a $61 million *decrease*, based on a 9.4% ROE. Indiana & Michigan requested hikes of $172 million and $58 million in Indiana and Michigan, respectively, based on a 10.5% ROE. In Michigan, the commission's staff proposed a $38 million raise, based on a 9.75% ROE, and the attorney general recommended a boost of $28 million, based on a 9.25% ROE. In Arkansas, SWEPCO reached a settlement, which awaits a commission order, calling for a $24 million boost, based on a 9.45% ROE. New tariffs in each of these states are expected to take effect in the first quarter of 2020. SWEPCO will file in Louisiana later this month, and AEP Ohio will do so in 2020.

We expect steady profit growth in 2019 and 2020. The company is benefiting from rate relief and increased investment in its transmission system. Our share-earnings estimates are within AEP's targeted ranges of $4.14-$4.24 and $4.25-$4.45, respectively.

The board of directors raised the dividend in the fourth quarter. The increase was $0.03 a share (4.5%) quarterly. AEP's target for the payout ratio is a range of 60%-70%.

The dividend yield of this high-quality stock is about average for a utility. Total return potential is unexciting for the 18-month span and the 3- to 5-year period.

Paul E. Debbas, CFA *December 13, 2019*

(A) Dil. EPS. Excl. nonrec. gains (losses): '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; disc. ops.: '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). '16 EPS don't sum due to rounding. Next egs. report due late Feb. **(B)** Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '18: $12.04/sh. **(D)** In mill. **(E)** Rate base: various. Rates all'd on com. eq.: 9.3%-10.9%; earn. on avg. com. eq., '18: 10.3%. Regul. Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

AVISTA CORP. NYSE-AVA

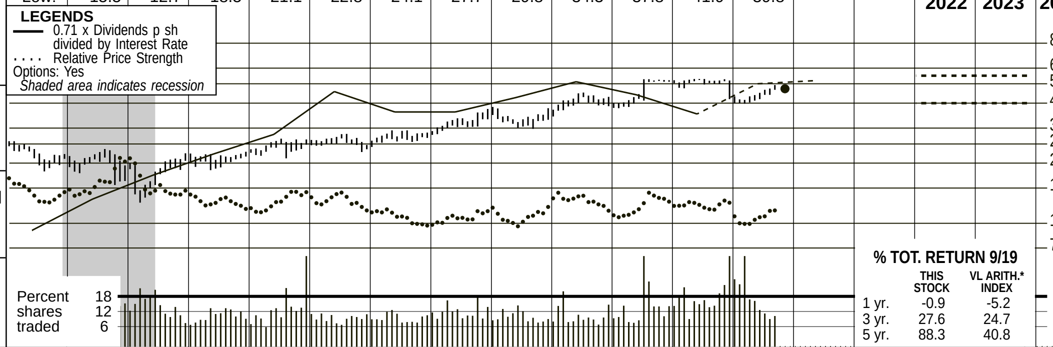
RECENT PRICE 47.20 | P/E RATIO 22.6 (Trailing: 15.8; Median: 17.0) | RELATIVE P/E RATIO 1.34 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 New 12/14/18
SAFETY 2 Raised 5/7/10
TECHNICAL 3 Raised 10/18/19
BETA .60 (1.00 = Market)

High:	23.6	22.4	22.8	26.5	28.0	29.3	37.4	38.3	45.2	52.8	52.9	49.3
Low:	15.5	12.7	18.5	21.1	22.8	24.1	27.7	29.8	34.3	37.8	41.9	39.8

18-Month Target Price Range
Low-High: $41-$55 | Midpoint (% to Mid): $48 (0%)

Target Price Range 2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+15%)	7%
Low	40	(-15%)	Nil

Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	117	151	131
to Sell	125	100	108
Hld's(000)	49709	51692	53198

% TOT. RETURN 9/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.9	-5.2
3 yr.	27.6	24.7
5 yr.	88.3	40.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
23.24	23.76	27.98	28.68	26.80	30.77	27.58	27.29	27.73	25.86	26.94	23.66	23.83	22.47	22.08	21.27	20.15	20.60	Revenues per sh	21.75
2.63	2.35	2.72	4.27	2.93	3.98	4.45	3.62	3.78	3.70	4.36	4.36	4.92	5.30	4.87	5.01	6.00	5.20	"Cash Flow" per sh	6.00
1.02	.73	.92	1.47	.72	1.36	1.58	1.65	1.72	1.32	1.85	1.84	1.89	2.15	1.95	2.07	2.95	2.15	Earnings per sh A	2.50
.49	.52	.55	.57	.60	.69	.81	1.00	1.10	1.16	1.22	1.27	1.32	1.37	1.43	1.49	1.55	1.61	Div'd Decl'd per sh B ■	1.80
2.21	2.47	3.23	3.14	4.04	4.09	3.86	3.64	4.20	4.61	5.05	5.47	6.46	6.34	6.30	6.46	6.65	6.05	Cap'l Spending per sh	6.00
15.54	15.54	15.87	17.46	17.27	18.30	19.17	19.71	20.30	21.06	21.61	23.84	24.53	25.69	26.41	26.99	28.85	29.55	Book Value per sh C	32.25
48.34	48.47	48.59	52.51	52.91	54.49	54.84	57.12	58.42	59.81	60.08	62.24	62.31	64.19	65.49	65.69	67.00	68.00	Common Shs Outst'g D	71.00
13.8	24.4	19.4	15.4	30.9	15.0	11.4	12.7	14.1	19.3	14.6	17.3	17.6	18.8	23.4	24.5	Bold figures are		Avg Ann'l P/E Ratio	19.0
.79	1.29	1.03	.83	1.64	.90	.76	.81	.88	1.23	.82	.91	.89	.99	1.18	1.32	Value Line		Relative P/E Ratio	1.05
3.5%	2.9%	3.0%	2.5%	2.7%	3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%	4.0%	3.4%	3.1%	2.9%	estimates		Avg Ann'l Div'd Yield	3.8%

CAPITAL STRUCTURE as of 6/30/19
Total Debt $1975.4 mill. **Due in 5 Yrs** $604.2 mill.
LT Debt $1753.0 mill. **LT Interest** $76.2 mill.
Incl. $51.5 mill. debt to affiliated trusts; $57.2 mill. capitalized leases.
(LT interest earned: 2.8x)
Pension Assets-12/18 $544.0 mill. **Oblig** $671.6 mill.
Pfd Stock None

Common Stock 66,111,437 shs. as of 8/2/19

MARKET CAP: $3.1 billion (Mid Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1512.6	1558.7	1619.8	1547.0	1618.5	1472.6	1484.8	1442.5	1445.9	1396.9	1350	1400	Revenues ($mill)	1550
87.1	92.4	100.2	78.2	111.1	114.2	118.1	137.2	126.1	136.4	195	145	Net Profit ($mill)	180
34.3%	35.0%	35.4%	34.4%	36.0%	37.6%	36.3%	36.3%	36.5%	16.0%	16.0%	16.5%	Income Tax Rate	16.5%
4.2%	4.0%	5.2%	8.3%	8.8%	11.1%	10.1%	8.1%	7.9%	7.7%	6.0%	8.0%	AFUDC % to Net Profit	7.0%
50.9%	51.6%	51.4%	50.8%	51.4%	51.0%	50.0%	51.2%	47.2%	50.5%	50.0%	50.5%	Long-Term Debt Ratio	50.0%
49.1%	48.4%	48.6%	49.2%	48.6%	49.0%	50.0%	48.8%	52.8%	49.5%	50.0%	49.5%	Common Equity Ratio	50.0%
2139.0	2325.3	2439.9	2561.2	2669.7	3027.3	3060.3	3379.0	3273.2	3580.3	3865	4045	Total Capital ($mill)	4600
2607.0	2714.2	2860.8	3023.7	3202.4	3620.0	3898.6	4147.5	4398.8	4648.9	4890	5090	Net Plant ($mill)	5650
5.5%	5.4%	5.5%	4.3%	5.4%	4.9%	5.1%	5.3%	5.0%	4.8%	6.0%	4.5%	Return on Total Cap'l	5.0%
8.3%	8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.0%	7.0%	Return on Shr. Equity	8.0%
8.3%	8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	7.7%	10.0%	7.0%	Return on Com Equity E	8.0%
4.1%	3.3%	3.1%	.8%	2.9%	2.4%	2.3%	3.0%	1.9%	2.2%	5.0%	2.0%	Retained to Com Eq	2.5%
51%	60%	64%	88%	66%	69%	70%	64%	73%	72%	52%	75%	All Div'ds to Net Prof	71%

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-1.2	+4.7	-3.7
Avg. Indust. Use (MWH)	1314	1367	1344
Avg. Indust. Revs. per KWH (¢)	6.09	6.11	6.20
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+1.2	+1.4
Fixed Charge Cov. (%)	333	296	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-2.5%	-4.0%	Nil
"Cash Flow"	3.0%	5.0%	3.0%
Earnings	5.5%	5.0%	3.5%
Dividends	8.5%	4.5%	4.0%
Book Value	4.0%	4.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	418.2	318.8	303.4	402.1	1442.5
2017	436.5	314.5	297.1	397.8	1445.9
2018	409.4	319.3	296.0	372.2	1396.9
2019	396.5	300.8	288.7	364	1350
2020	410	315	295	380	1400

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.92	.43	.19	.62	2.15
2017	.96	.34	.07	.58	1.95
2018	.83	.39	.15	.70	2.07
2019	1.76	.38	.15	.66	2.95
2020	.90	.40	.15	.70	2.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.33	.33	.33	.33	1.32
2016	.3425	.3425	.3425	.3425	1.37
2017	.3575	.3575	.3575	.3575	1.43
2018	.3725	.3725	.3725	.3725	1.49
2019	.3875	.3875	.3875		

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies electricity to part of Alaska & gas to part of Oregon. Customers: 402,000 electric, 350,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 38%; commercial, 32%; industrial, 11%; wholesale, 9%; other, 10%. Generating sources: hydro, 31%; gas & coal, 27%; purch., 42%. Fuel costs: 35% of revs. '18 reported depr. rate (Avista Utilities): 3.2%. Has 2,000 employees. Chairman & CEO: Scott L. Morris. Pres.: Dennis Vermillion. Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Internet: www.avistacorp.com.

Avista has rate cases pending in Washington and Idaho. The utility needs rate relief because it isn't earning an adequate return on equity—likely just 7.5% in 2019. In Washington, Avista filed for electric and gas rate increases of $45.8 million (9.1%) and $12.9 million (13.8%), respectively, to take effect on April 1, 2020 and $18.9 million (3.5%) and $6.5 million (6.1%), respectively, to take effect a year later. The utility is seeking a 9.9% return on a 50% common-equity ratio. In Idaho, the company reached a settlement that would have a net benefit to Avista of $2.3 million, based on a 9.5% return on a 50% common-equity ratio. New tariffs would take effect at the start of December.

The Oregon commission approved the settlement of the utility's gas rate case. This will raise tariffs $3.6 million (4.2%), effective January 15th. The allowed ROE will be 9.4%, and the common-equity ratio 50%.

Avista's 2015 rate order in Washington is under review. Following a complaint from the state attorney general's office, the commission is deciding whether a refund of previously collected revenues is in order, and if so, how much the refund will be. Some parties believe the refund should be $40 million (pretax). Our estimates assume no refund, but if one occurs, we will *include* this in our earnings presentation. A ruling is expected by yearend.

Profits will probably return to a more typical level in 2020 after an unusually high tally this year. In the first quarter, Avista received a breakup fee of $103 million ($1.01 a share) after the proposed acquisition of the company was rejected by regulators. Our 2019 estimate is within management's guidance of $2.83-$3.03 a share. We assume in our 2020 estimate that Avista gets reasonable treatment in the aforementioned rate cases.

Avista stock has a dividend yield that is slightly above the utility average. The projected total returns for the 18-month and 3- to 5-year periods are unappealing. However, Avista has already demonstrated its willingness to be acquired, so the stock holds some speculative appeal on this basis. It appears as though takeover considerations are not reflected in the recent price.

Paul E. Debbas, CFA *October 25, 2019*

(A) Diluted EPS. Excl. nonrec. gain (losses): '03, (3¢); '14, 9¢; '17, (16¢); gains (loss) on discontinued ops.: '03, (10¢); '14, $1.17; '15, 8¢. '16 EPS don't sum due to rounding. Next earnings report due early Nov. (B) Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. def'd chgs. In '18: $10.23/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in WA in '18: 9.5%; in ID in '17: 9.5%; in OR in '17: 9.4%; earned on avg. com. eq., '18: 7.8%. Regulatory Climate: WA, Below Avg.; ID, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	70

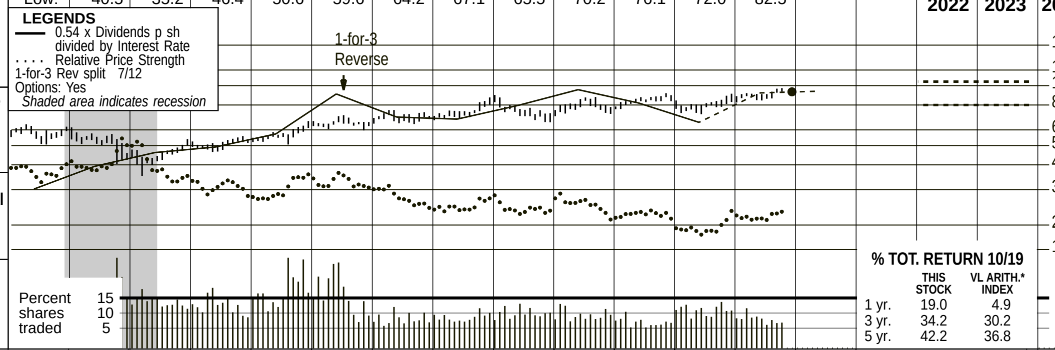
DUKE ENERGY NYSE-DUK

RECENT PRICE 93.15 | P/E RATIO 18.3 (Trailing: 19.4 / Median: 18.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 2 Raised 10/25/19
SAFETY 2 New 6/1/07
TECHNICAL 1 Raised 11/8/19
BETA .50 (1.00 = Market)

High:	61.8	53.8	55.8	66.4	71.1	75.5	87.3	90.0	87.8	91.8	91.4	97.4
Low:	40.5	35.2	46.4	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.0	82.5

Target Price Range 2022 2023 2024



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$85-$113	$99 (5%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+15%)	7%
Low	80	(-15%)	1%

Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	636	694	682
to Sell	598	572	586
Hld's(000)	442549	438644	7059915

% TOT. RETURN 10/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.0	4.9
3 yr.	34.2	30.2
5 yr.	42.2	36.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
- -	- -	- -	25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	**34.40**	**34.35**	Revenues per sh	**36.50**
- -	- -	- -	7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	10.49	**11.80**	**12.05**	"Cash Flow" per sh	**13.50**
- -	- -	- -	2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.13	**5.05**	**5.20**	Earnings per sh A	**5.75**
- -	- -	- -	- -	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	**3.75**	**3.82**	Div'd Decl'd per sh B ■	**4.05**
- -	- -	- -	8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	**15.15**	**14.00**	Cap'l Spending per sh	**12.50**
- -	- -	- -	62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	**61.75**	**64.10**	Book Value per sh C	**69.50**
- -	- -	- -	418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	**733.00**	**754.00**	Common Shs Outst'g D	**770.00**
- -	- -	- -	- -	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	19.4	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
- -	- -	- -	- -	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	1.05	*Value Line*		Relative P/E Ratio	**.90**
- -	- -	- -	- -	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	*estimates*		Avg Ann'l Div'd Yield	**4.4%**

CAPITAL STRUCTURE as of 6/30/19
Total Debt $60833 mill. **Due in 5 Yrs** $22487 mill.
LT Debt $54342 mill. **LT Interest** $1984 mill.
Incl. $941 mill. capitalized leases.
(LT interest earned: 2.6x)
Leases, Uncapitalized Annual rentals $239 mill.
Pension Assets-12/18 $8233 mill.
Oblig $7869 mill.
Pfd Stock $973 mill. **Pfd Div'd** $58 mill.
40 mill. shs. 5.75%, cum., $25 liq. value, redeemable at $25.50 prior to 6/15/24.
Common Stock 728,601,060 shs.
as of 7/31/19
MARKET CAP: $68 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
12731	14272	14529	19624	24598	23925	23459	22743	23565	24521	**25200**	**25900**	Revenues ($mill)	**28200**
1461.0	1765.0	1839.0	2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	2928.0	**3735**	**3945**	Net Profit ($mill)	**4510**
34.4%	32.6%	31.3%	30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	14.2%	**12.5%**	**12.0%**	Income Tax Rate	**12.0%**
17.5%	22.7%	23.2%	22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	13.0%	**9.0%**	**8.0%**	AFUDC % to Net Profit	**8.0%**
42.6%	44.3%	45.1%	47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	**54.5%**	**54.5%**	Long-Term Debt Ratio	**55.0%**
57.4%	55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	**44.5%**	**45.0%**	Common Equity Ratio	**44.5%**
37863	40457	41451	77307	79482	78088	77222	86609	90774	94940	**101375**	**107825**	Total Capital ($mill)	**120500**
37950	40344	42661	68558	69490	70046	75709	82520	86391	91694	**97825**	**103150**	Net Plant ($mill)	**114300**
4.9%	5.5%	5.6%	3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	4.2%	**5.0%**	**5.0%**	Return on Total Cap'l	**5.0%**
6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	**8.0%**	**8.0%**	Return on Shr. Equity	**8.5%**
6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	**8.0%**	**8.0%**	Return on Com Equity E	**8.5%**
1.1%	2.1%	2.2%	.9%	1.5%	1.7%	1.5%	.6%	1.2%	1.0%	**2.0%**	**2.0%**	Retained to Com Eq	**2.5%**
84%	73%	72%	82%	78%	76%	79%	91%	83%	84%	**74%**	**73%**	All Div'ds to Net Prof	**70%**

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-.3	-2.0	+3.9
Avg. Indust. Use (MWH)	2908	2914	2953
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.4	+1.3	+1.4
Fixed Charge Cov. (%)	264	272	218

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	1.5%	1.0%	1.5%
"Cash Flow"	2.5%	4.5%	5.5%
Earnings	2.5%	.5%	6.0%
Dividends	7.0%	3.0%	2.5%
Book Value	1.0%	1.5%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	5377	5213	6576	5577	22743
2017	5729	5555	6482	5799	23565
2018	6135	5643	6628	6115	24521
2019	6163	5873	6940	*6224*	*25200*
2020	*6350*	*6000*	*7200*	*6350*	*25900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.83	.90	1.44	.54	3.71
2017	1.02	.98	1.36	.86	4.22
2018	1.17	.71	1.63	.61	4.13
2019	1.24	1.12	1.82	*.87*	*5.05*
2020	*1.30*	*1.10*	*1.85*	*.95*	*5.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.795	.795	.825	.825	3.24
2016	.825	.825	.855	.855	3.36
2017	.855	.855	.89	.89	3.49
2018	.89	.89	.9275	.9275	3.64
2019	.9275	.9275	.945		

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, & KY, and 1.6 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 44%; commercial, 28%; industrial, 14%; other, 14%. Generating sources: gas, 26%; nuclear, 26%; coal, 24%; other, 2%; purchased, 22%. Fuel costs: 31% of revs. '18 reported deprec. rate: 3.0%. Has 30,100 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

Duke Energy's electric utility subsidiaries in North Carolina have filed general rate cases. Duke Energy Carolinas requested an increase of $291 million (6.0%), and Duke Energy Progress filed for a hike of $464 million (12.3%). Each case is based on a 10.3% return on a 53% common-equity ratio. New rates are likely to take effect in the third quarter of 2020.

Electric rate cases are pending in Indiana and Kentucky, too. In Indiana, the utility filed for $395 million (15%), based on a 10.4% return on a 53% common-equity ratio. Duke sought $345 million in mid-2020 and $50 million in 2021. In Kentucky, the company requested $83 million (9.0%), based on a 10.6% return on a 52% common-equity ratio.

The North Carolina commission approved Piedmont Gas' settlement of its rate case. The utility had filed for an increase of $83 million (9.0%), based on a 10.6% return on a 52% common-equity ratio. The settlement boosted rates by $28 million (3.1%), based on a 9.7% return on a 52% common-equity ratio. New tariffs took effect on November 1st.

Rate relief is a key reason for the profit growth we expect in 2019 and 2020. In addition, in 2019 the comparisons are easy in the June and December quarters. Our 2019 EPS estimate is within the company's guidance of $4.95-$5.15 a share.

Duke completed the sale of a minority interest in its commercial renewable-energy portfolio. The sale proceeds were $415 million (before taxes). This will be used to retire debt.

Not everything is going well. Duke's utilities in South Carolina received disappointing rate orders, so the company appealed the decision to the state Supreme Court. Construction of a 47%-owned, $7.3 billion-$7.8 billion gas pipeline is on hold due to legal challenges. Even if a verdict from the U.S. Supreme Court is favorable, the in-service date won't occur until 2022. And due to the delays and cost overruns, Duke plans to add $2.5 billion of equity by year-end 2020. Finally, coal-ash pond closure costs remain controversial.

The dividend yield of this timely stock is above the utility average. But total return potential isn't appealing, either for the 18-month or the 2022-2024 period.

Paul E. Debbas, CFA *November 15, 2019*

(A) Diluted EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; '17, 15¢; '18, 41¢; losses on disc. ops.: '14, 80¢; '16, 60¢; '18 EPS don't sum due to rounding. Next earnings report due mid-Feb. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '18: $60.27/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '18 in NC: 9.9%; in '17 in SC: 10.1%; in '09 in OH: 10.63%; in '04 in IN: 10.3%; earned on avg. com. eq., '18: 6.8%. Reg. Clim.: NC Avg.; SC, OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	90

EDISON INTERNAT'L NYSE-EIX

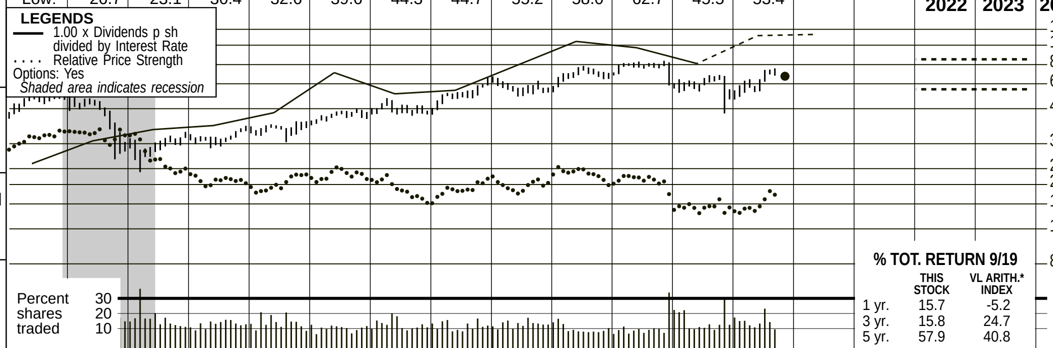
RECENT PRICE	69.89	P/E RATIO	14.1 (Trailing: NMF; Median: 13.0)	RELATIVE P/E RATIO	0.83	DIV'D YLD	3.5%	VALUE LINE

TIMELINESS 3 Raised 8/30/19
SAFETY 3 Lowered 11/23/18
TECHNICAL 2 Raised 10/25/19
BETA .60 (1.00 = Market)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	55.7	36.7	39.4	41.6	48.0	54.2	68.7	69.6	78.7	83.4	71.0	76.4
Low:	26.7	23.1	30.4	32.6	39.6	44.3	44.7	55.2	58.0	62.7	45.5	53.4

Target Price Range
2022 | 2023 | 2024

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$48-$83	$66 (-5%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+20%)	8%
Low	60	(-15%)	Nil

Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	270	299	267
to Sell	302	265	301
Hld's(000)	272637	267294	278546

% TOT. RETURN 9/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.7	-5.2
3 yr.	15.8	24.7
5 yr.	57.9	40.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	38.85	**37.00**	**38.50**	Revenues per sh	**43.00**
5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	4.69	**9.85**	**10.25**	"Cash Flow" per sh	**12.00**
2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	d1.26	**4.60**	**4.50**	Earnings per sh A	**5.50**
- -	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	2.43	**2.46**	**2.49**	Div'd Decl'd per sh B ■	**2.75**
3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	13.84	**13.15**	**13.50**	Cap'l Spending per sh	**13.75**
16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	32.10	**37.85**	**40.30**	Book Value per sh C	**48.75**
325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	**365.00**	**370.00**	Common Shs Outst'g D	**385.00**
7.0	37.6	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	- -	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**13.0**
.40	1.99	.62	.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	.87	- -			Relative P/E Ratio	**.70**
- -	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%	3.8%			Avg Ann'l Div'd Yield	**3.8%**

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
12374	12409	12760	11862	12581	13413	11524	11869	12320	12657	**13500**	**14250**	Revenues ($mill)	**16600**
1115.0	1153.0	1112.0	1594.0	1344.0	1539.0	1480.0	1422.0	1603.0	d290.0	**1680**	**1775**	Net Profit ($mill)	**2215**
33.0%	32.1%	25.7%	14.3%	25.2%	22.4%	6.6%	11.1%	5.0%	- -	**10.0%**	**10.0%**	Income Tax Rate	**10.0%**
10.5%	16.9%	14.8%	8.5%	7.8%	5.8%	8.0%	6.8%	7.2%	- -	**9.0%**	**9.0%**	AFUDC % to Net Profit	**7.0%**
49.3%	51.8%	55.3%	45.2%	45.7%	44.1%	45.0%	41.8%	45.6%	53.6%	**52.0%**	**52.0%**	Long-Term Debt Ratio	**51.5%**
46.5%	44.3%	40.6%	46.2%	46.2%	47.2%	46.7%	49.2%	45.8%	38.3%	**41.5%**	**41.5%**	Common Equity Ratio	**43.5%**
21185	23861	24773	20422	21516	23216	24352	24362	25506	27284	**33450**	**35750**	Total Capital ($mill)	**43200**
21966	24778	32116	30273	30455	32981	35085	37000	39050	41348	**44000**	**46850**	Net Plant ($mill)	**55100**
6.9%	6.3%	6.0%	8.9%	7.3%	7.7%	7.1%	6.9%	7.3%	.1%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.5%**
10.4%	10.0%	10.0%	14.2%	11.5%	11.9%	11.1%	10.0%	11.6%	NMF	**10.5%**	**10.5%**	Return on Shr. Equity	**10.5%**
10.8%	10.4%	10.5%	15.9%	12.5%	13.0%	12.0%	10.8%	12.7%	NMF	**11.5%**	**11.0%**	Return on Com Equity E	**11.0%**
6.7%	6.5%	6.3%	11.4%	8.1%	8.8%	7.2%	5.6%	6.6%	NMF	**5.0%**	**5.0%**	Retained to Com Eq	**5.5%**
41%	40%	43%	32%	40%	37%	44%	53%	52%	NMF	**58%**	**58%**	All Div'ds to Net Prof	**53%**

CAPITAL STRUCTURE as of 6/30/19
Total Debt $17575 mill. **Due in 5 Yrs** $4864 mill.
LT Debt $15883 mill. **LT Interest** $768 mill.
(Interest not earned.)
Leases, Uncapitalized Annual rentals $190 mill.
Pens. Assets-12/18 $3321 mill. **Oblig** $3880 mill.
Pfd Stock $2193 mill. **Pfd Div'd** $120 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. variable, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 325,811,206 shs. **as of 7/23/19**
MARKET CAP: $23 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-2.6	+.2	-.4
Avg. Indust. Use (MWH)	664	643	667
Avg. Indust. Revs. per KWH (¢)	6.51	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	23091	23508	23766
Annual Load Factor (%)	50.7	NA	NA
% Change Customers (yr-end)	+.5	+.7	+.6
Fixed Charge Cov. (%)	246	241	NMF

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-1.0%	- -	*2.0%*
"Cash Flow"	1.5%	-1.0%	*5.5%*
Earnings	-3.5%	-9.0%	*NMF*
Dividends	6.5%	11.0%	*3.5%*
Book Value	3.0%	3.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2440	2777	3767	2885	11869
2017	2463	2965	3672	3220	12320
2018	2564	2815	4269	3009	12657
2019	2824	2812	**4500**	**3364**	**13500**
2020	**2900**	**3100**	**4700**	**3550**	**14250**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.85	.86	1.27	.96	3.94
2017	1.11	.85	1.43	1.12	4.51
2018	.82	.84	1.57	d4.49	d1.26
2019	.63	1.58	**1.45**	**.94**	**4.60**
2020	**1.00**	**.95**	**1.55**	**1.00**	**4.50**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.4175	.4175	.4175	.4175	1.67
2016	.48	.48	.48	.48	1.92
2017	.5425	.5425	.5425	.5425	2.17
2018	.605	.605	.605	.605	2.42
2019	.6125	.6125	.6125	.6125	

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.1 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 37%; commercial, 44%; industrial, 6%; other, 13%. Generating sources: gas, 6%; nuclear, 6%; hydro, 5%; purchased, 83%. Fuel costs: 38% of revs. '18 reported depr. rate: 3.7%. Has 12,500 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

A law was passed in California that addresses future wildfire liabilities for utilities, including Edison International's subsidiary. The new law established a $21 billion fund (half of which is supplied by the utilities) to pay for future liabilities. Southern California Edison's contribution was $2.4 billion, which the parent raised through an equal split of debt and equity. (How this will be accounted for is still unclear.) The law also changed the way liability is determined so that it is not as easy as it was previously to place the blame on utilities. However, the law does not affect liabilities associated with previous wildfires. In the fourth quarter of 2018, the company took a charge of $5.60 a share as a reserve for its minimum estimate of these liabilities. So far, it has not taken any additional charges, but this cannot be ruled out.

We no longer think there is a risk of a dividend cut. In fact, we estimate the board will raise the dividend modestly at its meeting in December, effective with the payment in the first quarter of 2020.

Financing needs are significant. Besides the cash needed for SCE's contribution to the wildlife liability fund, the company is issuing additional common equity and long-term debt for its high (and rising) capital budget. Capital spending needs for wildfire prevention are considerably higher, but the utility is also spending additional monies for other functions, such as modernization of the electric grid.

We reduced our 2019 and 2020 share-earnings estimates by $0.15 and $0.30, respectively. The main reason for the cuts is the significant rise in average shares outstanding, which is much greater than we had estimated three months ago.

A cost-of-capital filing is pending with the California commission. SCE is requesting an allowed return on equity of 11.45% and a common-equity ratio of 52% (up from the currently allowed 48%). An order is due in time for it to take effect at the start of 2020.

This stock has a dividend yield that is slightly above the industry average. However, total return potential is unappealing for the 18-month and 3- to 5-year periods. And the company still faces risks related to past wildfires.

Paul E. Debbas, CFA *October 25, 2019*

(A) Diluted EPS. Excl. nonrec. gains (losses): '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); '18, (15¢); 1Q '19, 22¢; 2Q '19, (38¢); gains (loss) from disc. ops.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. Next earnings report due late Oct. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. deferred charges. In '18: $16.51/sh. (D) In millions. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.45%; earned on avg. com. eq., '18: NMF. Regulatory Climate: Average.

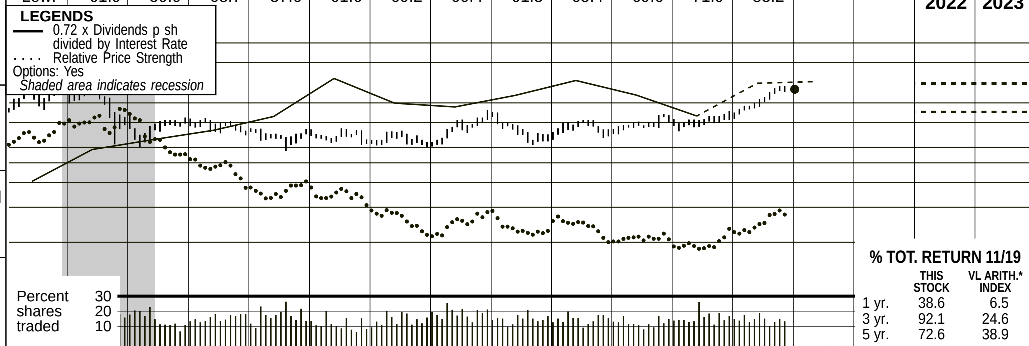
Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	55
Earnings Predictability	15

ENTERGY CORP. NYSE-ETR

RECENT PRICE **116.92** | P/E RATIO **24.8** (Trailing: 24.6 Median: 12.0) | RELATIVE P/E RATIO **1.43** | DIV'D YLD **3.2%** | VALUE LINE

TIMELINESS 3 Raised 10/26/18
SAFETY 2 Raised 12/13/19
TECHNICAL 2 Raised 11/15/19
BETA .60 (1.00 = Market)

High:	127.5	86.6	84.3	74.5	74.5	72.6	92.0	90.3	82.1	87.9	90.8	122.1
Low:	61.9	59.9	68.7	57.6	61.6	60.2	60.4	61.3	65.4	69.6	71.9	83.2



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$83-$127	$105 (-10%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	125	(+5%)	5%
Low	90	(-25%)	-2%

Institutional Decisions

	1Q2019	2Q2019	3Q2019
to Buy	307	260	298
to Sell	253	281	248
Hld's(000)	166792	175686	175725

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
40.17	46.69	46.61	53.94	59.47	69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	61.35	58.23	**55.05**	**54.00**	Revenues per sh	**51.50**
7.43	8.33	8.18	10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	16.70	16.50	**15.50**	**16.65**	"Cash Flow" per sh	**18.50**
3.69	3.93	4.40	5.36	5.60	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	5.19	5.88	**4.80**	**5.50**	Earnings per sh A	**6.75**
1.60	1.89	2.16	2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	3.50	3.58	**3.66**	**3.74**	Div'd Decl'd per sh B ■ †	**4.30**
6.85	6.51	6.72	9.44	10.29	13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	22.07	22.45	**23.00**	**19.55**	Cap'l Spending per sh	**20.25**
38.02	38.26	35.71	40.45	40.71	42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	44.28	46.78	**48.65**	**50.55**	Book Value per sh C	**58.25**
228.90	216.83	216.83	202.67	193.12	189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	180.52	189.06	**199.00**	**200.00**	Common Shs Outst'g D	**210.00**
13.8	15.1	16.3	14.3	19.3	16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	13.8	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
.79	.80	.87	.77	1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.74	*Value Line*		Relative P/E Ratio	**.90**
3.1%	3.2%	3.0%	2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%	4.4%	*estimates*		Avg Ann'l Div'd Yield	**4.0%**
						10746	11488	11229	10302	11391	12495	11513	10846	11074	11009	**10950**	**10800**	Revenues ($mill)	**10800**
						1251.1	1270.3	1367.4	1091.9	904.5	1060.0	1061.2	1249.8	950.7	1092.1	**955**	**1115**	Net Profit ($mill)	**1425**
						33.6%	32.7%	17.3%	13.0%	26.7%	37.8%	2.2%	11.3%	1.8%	NMF	**8.0%**	**23.0%**	Income Tax Rate	**23.0%**
						7.4%	7.4%	8.9%	11.9%	10.1%	9.3%	7.4%	8.1%	14.7%	17.5%	**23.0%**	**15.0%**	AFUDC % to Net Profit	**14.0%**
						55.3%	56.3%	52.2%	55.8%	55.1%	54.9%	57.8%	63.6%	63.6%	63.2%	**63.5%**	**63.0%**	Long-Term Debt Ratio	**60.5%**
						43.1%	42.1%	46.4%	42.9%	43.6%	43.8%	40.8%	35.5%	35.5%	35.9%	**36.0%**	**36.0%**	Common Equity Ratio	**39.0%**
						19985	20166	19324	21432	22109	22842	22714	22777	22528	24602	**27075**	**28050**	Total Capital ($mill)	**31500**
						23389	23848	25609	27299	27882	28723	27824	27921	29664	31974	**34450**	**36175**	Net Plant ($mill)	**41400**
						7.6%	7.7%	8.5%	6.4%	5.4%	6.0%	6.0%	6.9%	5.7%	5.8%	**5.0%**	**5.5%**	Return on Total Cap'l	**6.0%**
						14.0%	14.4%	14.8%	11.5%	9.1%	10.3%	11.1%	15.1%	11.6%	12.0%	**9.5%**	**11.0%**	Return on Shr. Equity	**11.5%**
						14.3%	14.7%	15.0%	11.6%	9.2%	10.4%	11.2%	15.2%	11.7%	12.2%	**9.5%**	**11.0%**	Return on Com Equity E	**11.5%**
						7.6%	7.6%	8.4%	5.2%	3.0%	4.4%	4.8%	7.7%	3.9%	4.9%	**2.5%**	**3.5%**	Retained to Com Eq	**4.0%**
						48%	49%	45%	56%	68%	58%	58%	50%	68%	61%	**76%**	**68%**	All Div'ds to Net Prof	**64%**

CAPITAL STRUCTURE as of 9/30/19
Total Debt $19376 mill. **Due in 5 Yrs** $6984.3 mill.
LT Debt $16938 mill. **LT Interest** $762.2 mill.
Incl. $338.4 mill. of securitization bonds and $20.4 mill. of capitalized leases.
(LT interest earned: 1.7x)
Leases, Uncapitalized Annual rentals $94.0 mill.
Pension Assets-12/18 $5497.4 mill. **Oblig** $7404.9 mill.
Pfd Stock $219.4 mill. **Pfd Div'd** $13.8 mill.
642,307 shs. 4.32%-7.5%, $100 par; 250,000 shs. 8.75%, all without sinking fund.
Common Stock 199,102,083 shs. **as of 10/31/19**
MARKET CAP: $23 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+.3	+.2	+4.1
Avg. Indust. Use (MWH)	989	1034	946
Avg. Indust. Revs. per KWH(¢)	5.09	5.41	5.16
Capacity at Peak (Mw)	24656	24279	23121
Peak Load, Summer (Mw)	21387	21671	21587
Annual Load Factor (%)	63	62	65
% Change Customers (yr-end)	+.8	+.6	+.6
Fixed Charge Cov. (%)	258	169	95

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	- -	-.5%	-2.5%
"Cash Flow"	4.0%	1.0%	1.0%
Earnings	.5%	-.5%	2.0%
Dividends	3.0%	1.0%	3.5%
Book Value	1.0%	-2.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2609	2462	3124	2648	10846
2017	2588	2618	3243	2623	11074
2018	2724	2669	3104	2512	11009
2019	2610	2666	3141	**2533**	**10950**
2020	**2650**	**2650**	**3050**	**2450**	**10800**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.28	3.16	2.16	.28	6.88
2017	.46	2.27	2.21	.25	5.19
2018	.73	1.34	3.42	.39	5.88
2019	1.32	1.22	1.82	**.44**	**4.80**
2020	**1.00**	**1.45**	**2.50**	**.55**	**5.50**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.83	.83	.83	.85	3.34
2016	.85	.85	.85	.87	3.42
2017	.87	.87	.87	.89	3.50
2018	.89	.89	.89	.91	3.58
2019	.91	.91	.91	.93	

BUSINESS: Entergy Corporation supplies electricity to 2.9 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 200,000 customers in Louisiana. Has a nonutility subsidiary that owns six nuclear units (two no longer operating). Electric revenue breakdown: residential, 38%; commercial, 26%; industrial, 27%; other, 9%. Generating sources: gas, 39%; nuclear, 27%; coal, 9%; purchased, 25%. Fuel costs: 35% of revenues. '18 reported depreciation rate: 2.8%. Has 13,700 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy has been one of the top-performing stocks in the electric utility industry in 2019. The share price has risen 35% this year. We think the market is reacting favorably to Entergy's ongoing transition from a partly nonregulated company to a regulated utility. The company has sold (or agreed to sell) its nonregulated nuclear units, which have faced unfavorable market conditions in recent years. This has reduced Entergy's business risk significantly; in fact, we raised the stock's Safety rank a notch, to 2 (Above Average). What's more, the company's utilities are performing well. The service area's economy is solid, and is producing respectable load growth. The rate base is expanding, in part through the construction and acquisition of gas-fired generating plants. The utilities are also benefiting from rate relief (in most cases) and regulatory mechanisms that provide for the recovery of certain capital expenditures without having to file a general rate case.

Investors should not be alarmed by the steep earnings decline we expect in 2019. In 2018, Entergy recorded tax credits that boosted the bottom line materially in the third quarter. There were no such credits in the same period this year. Note that the company is still incurring costs associated with its remaining nonregulated nuclear assets. We *include* these in our earnings presentation, even though management excludes them from its guidance of $5.25-$5.45 a share. A reduction in these expenses and growth from the utilities should produce higher profits in 2020.

The regulated business is not without risk. Entergy's utility in New Orleans received an unfavorable rate order that reduced its electric and gas tariffs by $16 million and $2 million, respectively, based on a 9.35% return on a 50% common-equity ratio.

The board of directors raised the dividend in the fourth quarter. The increase was two cents a share (2.2%) quarterly. It is likely that investors will have to wait until 2021 to see more-substantial dividend growth.

The stock has an average yield for a utility. Total return potential is negative for the 18-month span and unappealing for the 3- to 5-year period.

Paul E. Debbas, CFA *December 13, 2019*

(A) Diluted EPS. Excl. nonrec. gain (losses): '03, 33¢; '05, (21¢); '12, ($1.26); '13, ($1.14); '14, (56¢); '15, ($6.99); '16, ($10.14); '17, ($2.91); '18, ($1.25). Next earnings report due early Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '18: $28.37/sh. (D) In millions. (E) Rate base: Net original cost. Allowed ROE (blended): 9.95%; earned on avg. com. eq., '18: 12.6%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	60

EVERSOURCE ENERGY NYSE-ES

RECENT PRICE 81.08 | P/E RATIO 22.7 (Trailing: 24.2 Median: 18.0) | RELATIVE P/E RATIO 1.30 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Lowered 9/13/19
SAFETY 1 Raised 5/22/15
TECHNICAL 1 Raised 11/15/19
BETA .55 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$71-$93 $82 (0%)

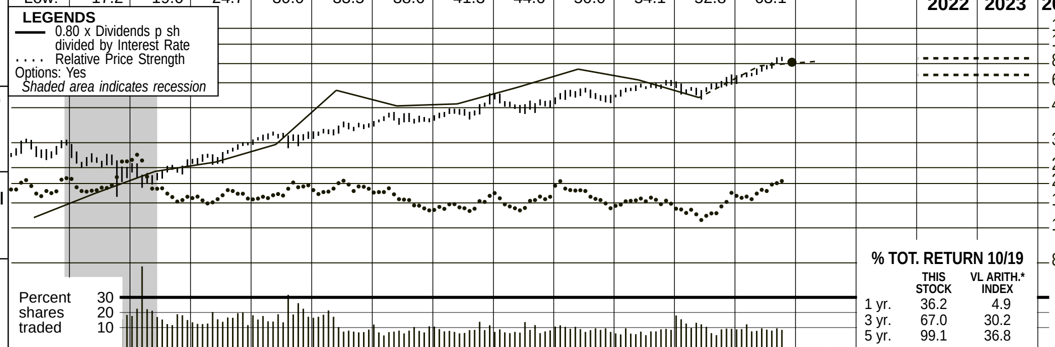
2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+5%)	4%
Low	70	(-15%)	Nil

Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	320	312	327
to Sell	259	288	269
Hld's(000)	237152	234072	255223

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8	60.4	66.1	70.5	86.6
Low:	17.2	19.0	24.7	30.0	33.5	38.6	41.3	44.6	50.0	54.1	52.8	63.1



2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	25.08	24.11	24.46	26.66	*26.25*	*25.80*	Revenues per sh	*27.50*
5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	4.94	5.46	5.84	6.64	*7.15*	*7.35*	"Cash Flow" per sh	*8.25*
1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	2.96	3.11	3.25	*3.45*	*3.65*	Earnings per sh A	*4.25*
.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	1.78	1.90	2.02	*2.14*	*2.26*	Div'd Decl'd per sh B ■	*2.65*
4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	5.44	6.24	7.41	7.96	*9.15*	*7.70*	Cap'l Spending per sh	*6.75*
17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	32.64	33.80	34.99	36.25	*37.70*	*40.40*	Book Value per sh C	*46.25*
127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	317.19	316.89	316.89	316.89	*324.00*	*337.00*	Common Shs Outst'g D	*350.00*
13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	18.7	19.5	18.7	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	.98	1.01	*Value Line*		Relative P/E Ratio	*1.00*
3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	3.2%	3.1%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 6/30/19
Total Debt $15152 mill. **Due in 5 Yrs** $5934.3 mill.
LT Debt $13601 mill. **LT Interest** $533.5 mill.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $11.5 mill.
Pension Assets-12/18 $4573.9 mill.
Oblig $5520.0 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption, call. at $50.50-$54.00; 430,000 shs 4.25%-4.78% not subject to mandatory redemption, call. at $102.80-$103.63.
Common Stock 323,602,045 shs. **as of 7/31/19**
MARKET CAP: $26 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	7954.8	7639.1	7752.0	8448.2	*8500*	*8700*	Revenues ($mill)	*9600*
335.6	377.8	400.3	533.0	793.7	827.1	886.0	949.8	995.5	1040.5	*1110*	*1215*	Net Profit ($mill)	*1490*
34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	37.9%	36.9%	36.8%	21.7%	*21.5%*	*21.5%*	Income Tax Rate	*21.5%*
4.6%	7.1%	8.6%	2.3%	1.4%	2.4%	2.9%	3.9%	4.7%	6.1%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
57.2%	55.1%	53.4%	43.7%	44.3%	45.9%	45.6%	44.8%	51.2%	52.4%	*53.0%*	*52.0%*	Long-Term Debt Ratio	*53.0%*
41.5%	43.6%	45.3%	55.4%	54.8%	53.2%	53.6%	54.4%	48.2%	46.9%	*46.5%*	*47.5%*	Common Equity Ratio	*46.5%*
8629.5	8741.8	8856.0	16675	17544	18738	19313	19697	23018	24474	*26375*	*28775*	Total Capital ($mill)	*34900*
8840.0	9567.7	10403	16605	17576	18647	19892	21351	23617	25610	*27300*	*28800*	Net Plant ($mill)	*32300*
5.4%	5.8%	5.9%	4.2%	5.5%	5.3%	5.5%	5.8%	5.2%	5.2%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
9.1%	9.6%	9.7%	5.7%	8.1%	8.2%	8.4%	8.7%	8.9%	8.9%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	8.5%	8.8%	8.9%	9.0%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
4.7%	5.0%	5.0%	1.6%	3.4%	3.5%	3.4%	3.5%	3.5%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
50%	49%	50%	72%	59%	58%	61%	60%	61%	62%	*62%*	*62%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-1.8	-2.6	+2.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.04	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	436	427	319

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-4.5%	2.0%	*1.5%*
"Cash Flow"	2.0%	5.0%	*5.5%*
Earnings	8.0%	7.0%	*5.5%*
Dividends	9.5%	8.0%	*5.5%*
Book Value	6.5%	5.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2055	1767	2039	1776	7639.1
2017	2105	1762	1988	1895	7752.0
2018	2288	1853	2271	2034	8448.2
2019	2416	1884	2176	*2024*	*8500*
2020	*2450*	*1950*	*2200*	*2100*	*8700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.77	.64	.83	.72	2.96
2017	.82	.72	.82	.75	3.11
2018	.85	.76	.91	.73	3.25
2019	.97	.74	.98	*.76*	*3.45*
2020	*1.03*	*.80*	*.97*	*.85*	*3.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.4175	.4175	.4175	.4175	1.67
2016	.445	.445	.445	.445	1.78
2017	.475	.475	.475	.475	1.90
2018	.505	.505	.505	.505	2.02
2019	.535	.535	.535		

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities that have 3.1 mill. electric, 504,000 gas, 230,000 water customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to 3/4 of New Hampshire's population; supplies power to western Massachusetts and parts of eastern Massachusetts & gas to central & eastern Massachusetts; supplies water to CT, MA, & NH. Acq'd NSTAR 4/12; Aquarion 12/17. Electric rev. breakdown: residential, 54%; commercial, 37%; industrial, 5%; other, 4%. Fuel costs: 37% of revs. '18 reported deprec. rate: 2.9%. Has 8,000 empls. Chairman, Pres. & CEO: James J. Judge. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy is likely to post steady earnings growth in 2019 and 2020. Some of the company's utilities are benefiting from rate relief. Expense control is effective. Eversource's transmission spending is boosting its earning power, as well. Our 2019 share-net estimate remains $3.45, the midpoint of Eversource's guidance of $3.40-$3.50. We are not changing our 2020 estimate of $3.65 a share. Our estimates, if attained, will produce profit growth of 6% annually. This is within the company's target of 5%-7% a year. Eversource's goal for annual dividend growth is the same range.

Public Service of New Hampshire has a rate case pending. The utility filed for an increase of $70 million, based on a return of 10.4% on a common-equity ratio of 54.85%. An interim hike of $28.3 million was effective on July 1st. PSNH is asking for new tariffs to take effect on July 1, 2020.

Eversource's joint venture with Orsted plans to build offshore wind projects. These would provide 1,714 megawatts of capacity and would come on line from 2022, 2023, and 2024. Costs have not been disclosed. These projects are expected to produce returns on investment exceeding those of the regulated utility operations. However, offshore wind entails significant construction risk.

Finances are solid. The common-equity ratio took a hit earlier this year due to an aftertax charge of $204 million to write off a transmission project that failed to win siting approval, but this was more than offset by the sale of $1.3 billion of stock. A third of the nearly 18 million shares was issued in June, and the remainder will come in May of 2020 through a forward sale agreement. Eversource has also switched to issuances rather than open-market purchases for its dividend reinvestment and other stock plans. The fixed-charge coverage is above the industry average, too. All told, the company merits a Financial Strength rating of A.

This high-quality equity has a high valuation. The dividend yield is a bit below average, by utility standards. And Eversource stock doesn't stand out for total return potential, either for the next 18 months or the 3- to 5-year period.

Paul E. Debbas, CFA *November 15, 2019*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢; '19, (64¢). Next earnings report due late Feb. **(B)** Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges. In '18: $28.59/sh. **(D)** In mill. **(E)** Rate allowed on com. eq. in MA: (elec.) '18, 10.0%; (gas) '16, 9.8%; in CT: (elec.) '18, 9.25%; (gas) '18, 9.3%; in NH: '10, 9.67%; earned on avg. com. eq., '18: 9.2%. Regulatory Climate: CT, Below Average; NH, Average; MA, Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	95

FIRSTENERGY NYSE-FE

RECENT PRICE **47.32** | P/E RATIO **30.3** (Trailing: 20.1; Median: 17.0) | RELATIVE P/E RATIO **1.74** | DIV'D YLD **3.4%** | VALUE LINE

TIMELINESS 3 Lowered 6/7/19
SAFETY 2 Raised 8/17/18
TECHNICAL 2 Raised 11/8/19
BETA .65 (1.00 = Market)

High:	84.0	53.6	47.8	46.5	51.1	46.8	40.8	41.7	36.6	35.2	39.9	49.1
Low:	41.2	35.3	33.6	36.1	40.4	31.3	30.0	28.9	29.3	27.9	29.3	36.3

Target Price Range
2022 | 2023 | 2024

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$35-$53 $44 (-5%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+25%)	*10%*
Low	45	(-5%)	*3%*

Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	293	328	320
to Sell	281	258	271
Hld's(000)	483814	498703	524158

% TOT. RETURN 10/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.5	4.9
3 yr.	59.9	30.2
5 yr.	59.5	36.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
37.31	37.76	36.35	36.03	42.00	44.70	41.70	43.76	38.87	36.57	35.60	35.74	35.48	32.92	31.49	22.00	*20.35*	*21.25*	Revenues per sh	*23.75*
4.79	7.60	7.55	7.22	8.34	9.04	8.80	8.50	5.75	6.05	6.30	4.55	6.33	6.53	6.54	3.98	*4.10*	*5.30*	"Cash Flow" per sh	*6.00*
1.47	2.77	2.84	3.82	4.22	4.38	3.32	3.25	1.88	2.13	2.97	.85	2.00	2.10	2.73	1.33	*1.50*	*2.55*	Earnings per sh A	*3.00*
1.50	1.91	1.71	1.85	2.05	2.20	2.20	2.20	2.20	2.20	1.65	1.44	1.44	1.44	1.44	1.82	*1.52*	*1.60*	Div'd Decl'd per sh B ■	*1.90*
2.60	2.57	3.66	4.12	5.36	9.47	7.23	6.44	5.45	7.09	6.90	8.42	6.83	6.93	6.38	5.23	*5.55*	*5.50*	Cap'l Spending per sh	*5.25*
25.13	26.04	27.86	28.30	29.45	27.17	28.08	28.03	31.75	31.29	30.32	29.49	29.33	14.11	8.81	13.17	*13.75*	*14.80*	Book Value per sh C	*18.00*
329.84	329.84	329.84	319.21	304.84	304.84	304.84	304.84	418.22	418.22	418.63	421.10	423.56	442.34	445.33	511.92	*540.00*	*543.00*	Common Shs Outst'g D	*550.00*
22.5	14.1	16.1	14.2	15.6	15.6	13.0	11.7	22.4	21.1	13.1	39.8	17.0	15.9	11.4	26.5	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
1.28	.74	.86	.77	.83	.94	.87	.74	1.41	1.34	.74	2.10	.86	.83	.57	1.43	*Value Line*		Relative P/E Ratio	*.90*
4.5%	4.9%	3.7%	3.4%	3.1%	3.2%	5.1%	5.8%	5.2%	4.9%	4.3%	4.3%	4.2%	4.3%	4.6%	5.2%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 9/30/19
Total Debt $20803 mill. **Due in 5 Yrs** $4656 mill.
LT Debt $19422 mill. **LT Interest** $921 mill.
Incl. $55 mill. capitalized leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $34 mill.

Pension Assets-12/18 $6984 mill. **Oblig** $9462 mill.

Pfd Stock None

Common Stock 540,311,707 shs.

MARKET CAP: $26 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
12712	13339	16258	15294	14903	15049	15029	14562	14022	11261	*11000*	*11550*	Revenues ($mill)	*13000*
1015.0	991.0	752.0	891.0	1245.0	356.0	844.0	892.0	1213.0	726.0	*810*	*1380*	Net Profit ($mill)	*1620*
19.6%	38.6%	41.3%	41.1%	36.1%	5.6%	35.7%	37.8%	37.2%	32.4%	*20.5%*	*22.5%*	Income Tax Rate	*22.5%*
12.8%	16.6%	9.3%	8.1%	6.0%	33.1%	13.9%	11.5%	6.5%	9.0%	*9.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
58.2%	59.5%	54.2%	53.7%	55.5%	60.7%	60.7%	74.5%	84.3%	72.3%	*73.0%*	*73.0%*	Long-Term Debt Ratio	*69.5%*
41.8%	40.5%	45.8%	46.3%	44.5%	39.3%	39.3%	25.5%	15.7%	27.4%	*27.0%*	*27.0%*	Common Equity Ratio	*30.5%*
20467	21124	28996	28263	28523	31596	31613	24433	25040	24565	*27450*	*30000*	Total Capital ($mill)	*32500*
19164	19788	30337	32903	33252	35783	37214	29387	28879	29911	*31525*	*33050*	Net Plant ($mill)	*37100*
6.9%	6.3%	4.0%	4.9%	6.0%	2.7%	4.3%	5.7%	7.0%	4.9%	*4.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
11.9%	11.6%	5.7%	6.8%	9.8%	2.9%	6.8%	14.3%	30.9%	10.7%	*11.0%*	*17.0%*	Return on Shr. Equity	*16.0%*
11.9%	11.6%	5.7%	6.8%	9.8%	2.9%	6.8%	14.3%	30.9%	9.7%	*10.5%*	*17.0%*	Return on Com Equity E	*16.0%*
4.0%	3.8%	NMF	NMF	2.6%	NMF	1.9%	4.5%	14.6%	NMF	*NMF*	*6.5%*	Retained to Com Eq	*6.0%*
66%	68%	117%	103%	74%	NMF	72%	68%	53%	108%	*104%*	*63%*	All Div'ds to Net Prof	*64%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+.3	-2.1	+4.2
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.5	+.4
Fixed Charge Cov. (%)	208	249	199

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-3.5%	-5.0%	*-3.0%*
"Cash Flow"	-3.5%	-1.0%	*1.0%*
Earnings	-7.0%	-2.5%	*6.5%*
Dividends	-2.5%	-5.0%	*3.5%*
Book Value	-8.0%	-17.5%	*7.0%*

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	3869	3401	3917	3375	14562
2017	3557	3309	3714	3442	14022
2018	2862	2625	3064	2710	11261
2019	2883	2516	2963	*2638*	*11000*
2020	*3000*	*2750*	*3100*	*2700*	*11550*

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.77	.34	.89	.10	2.10
2017	.71	.59	.95	.49	2.73
2018	.01	.27	.66	.34	1.33
2019	.66	.63	.72	*d.51*	*1.50*
2020	*.70*	*.65*	*.75*	*.45*	*2.55*

QUARTERLY DIVIDENDS PAID B ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.36	.36	.36	.36	1.44
2016	.36	.36	.36	.36	1.44
2017	.36	.36	.36	.36	1.44
2018	.36	.36	.36	.36	1.44
2019	.38	.38	.38		

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, Jersey Central Power & Light, West Penn Power, Potomac Edison, & Mon Power. Provides electric service to 6.1 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown by customer class not available. Generating sources: coal, 44%; nuclear, 26%; purchased, 30%. Fuel costs: 32% of revenues. '18 reported deprec. rate: 2.6%. Has 12,500 employees. Chairman: George M. Smart. President & CEO: Charles E. Jones. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

In the next few years, FirstEnergy's earning power will benefit from various capital spending programs. The company's utilities in Ohio will spend $516 million over a three-year period to modernize the electric grid. This is recoverable through a rider (surcharge) on customers' bills. Similarly, Jersey Central Power & Light will spend $97 million through the end of 2020. This is recoverable through 2020. FirstEnergy's utilities in Pennsylvania are proposing to spend $572 million from 2020 through 2024 to improve their electric infrastructure. This would be recovered through a rider. The company expects a ruling by yearend. Finally, FirstEnergy is spending $1.2 billion a year through 2021 on electric transmission. Most of this is recoverable through forward-looking regulatory mechanisms, and JCP&L is asking the Federal Energy Regulatory Commission to approve similar treatment in New Jersey beginning in 2020. This would mean that at least 85% of FirstEnergy's transmission spending would be recovered this way.

Investors should not be alarmed by the loss we estimate for the fourth quarter of 2019. Each year in the December period, FirstEnergy records a noncash mark-to-market accounting item associated with its pension plan. Management estimates that this will amount to a charge of $400 million-$1 billion; our estimate incorporates the midpoint of this range. (The final amount will be determined by the discount rate and asset returns at yearend.) The company's 2019 guidance (on a GAAP basis) is $0.76-$1.90 a share as a result of this wide range. We include no such item in our 2020 estimate of $2.55 a share, which is within FirstEnergy's targeted range of $2.40-$2.60.

We think the board of directors will raise the dividend, effective with the first-quarter payment. We estimate a hike of $0.02 a share (5.3%) in the quarterly payout, the same increase as a year ago.

The dividend yield of this stock is not significantly above the utility average. Projected total returns over the 18-month period are negative, and total return potential over the 3- to 5-year period, like those of most other utility issues, is unspectacular.

Paul E. Debbas, CFA *November 15, 2019*

(A) Dil. EPS. Excl. nonrec. losses: '12, 29¢; '13, $2.07; '14, 17¢; '15, 63¢; '16, $16.59; '17, $6.61; gains (loss) from disc. ops.: '14, 20¢; '18, 66¢; '19, (11¢). '17, '18 EPS don't sum due to rounding or chg. in shs. Next egs. due late Feb. **(B)** Div'ds pd. early Mar., June, Sept., & Dec. 5 div'ds in '04 & '18, 3 in '13. ■ Div'd reinv. avail. **(C)** Incl. intang. In '18: $11.15/sh. **(D)** In mill. **(E)** Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.75%-11.7%; earned avg. com. eq., '18: 12.7%. Regul. Climate: OH Above Avg.; PA, NJ Avg.; MD, WV Below Avg.

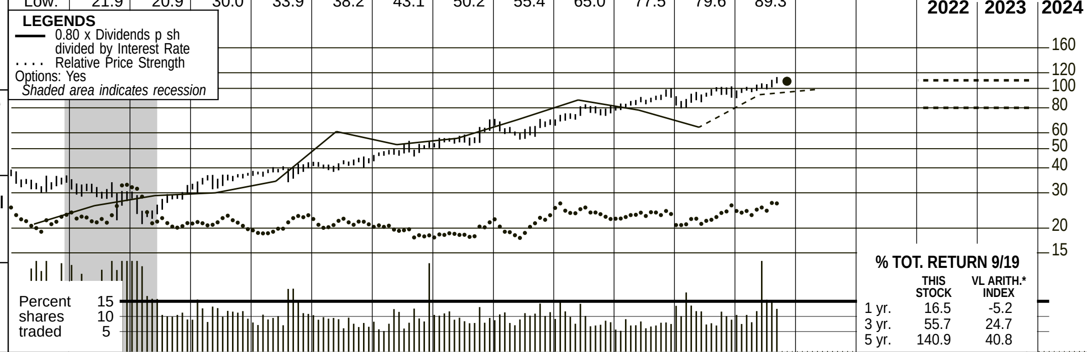
Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	20
Earnings Predictability	40

IDACORP, INC. NYSE-IDA

RECENT PRICE **108.62** | P/E RATIO **24.4** (Trailing: 24.5 / Median: 14.0) | RELATIVE P/E RATIO **1.44** | DIV'D YLD **2.5%** | **VALUE LINE**

TIMELINESS 3 Lowered 3/1/19
SAFETY 2 Raised 8/2/13
TECHNICAL 3 Raised 9/20/19
BETA .55 (1.00 = Market)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5	83.4	100.0	102.4	114.0
Low:	21.9	20.9	30.0	33.9	38.2	43.1	50.2	55.4	65.0	77.5	79.6	89.3



Target Price Range 2022 | 2023 | 2024

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$94-$126	$110 (0%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(Nil)	3%
Low	80	(-25%)	-4%

Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	160	169	163
to Sell	143	138	149
Hld's(000)	38724	38566	38770

% TOT. RETURN 9/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.5	-5.2
3 yr.	55.7	24.7
5 yr.	140.9	40.8

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	27.19	**27.80**	**28.45**	Revenues per sh	**30.50**
	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.85	**7.90**	**8.15**	"Cash Flow" per sh	**9.50**
	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.49	**4.45**	**4.60**	Earnings per sh A	**5.25**
	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	**2.56**	**2.73**	Div'd Decl'd per sh B ■ †	**3.35**
	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	5.51	**6.35**	**6.55**	Cap'l Spending per sh	**7.25**
	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	47.01	**48.85**	**50.65**	Book Value per sh C	**56.25**
	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.42	**50.40**	**50.40**	Common Shs Outst'g D	**50.40**
	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	20.5	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**18.0**
	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	*estimates*		Relative P/E Ratio	**1.00**
	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	2.6%			Avg Ann'l Div'd Yield	**3.5%**

CAPITAL STRUCTURE as of 6/30/19
Total Debt $1835.5 mill. **Due in 5 Yrs** $250.0 mill.
LT Debt $1835.5 mill. **LT Interest** $85.4 mill.
(LT interest earned: 3.5x)

Pension Assets-12/18 $650.6 mill.
Oblig $951.9 mill.

Pfd Stock None

Common Stock 50,397,121 shs.
as of 7/26/19

MARKET CAP: $5.5 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	1370.8	**1400**	**1435**	Revenues ($mill)	**1535**
124.4	142.5	166.9	168.9	182.4	193.5	194.7	198.3	212.4	226.8	**225**	**230**	Net Profit ($mill)	**270**
15.2%	- -	- -	13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	7.1%	**10.5%**	**10.5%**	Income Tax Rate	**10.5%**
10.5%	19.1%	23.3%	20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	15.2%	**16.0%**	**15.0%**	AFUDC % to Net Profit	**14.0%**
50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	43.6%	**41.5%**	**43.0%**	Long-Term Debt Ratio	**43.5%**
49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	56.4%	**58.5%**	**57.0%**	Common Equity Ratio	**56.5%**
2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	4205.1	**4195**	**4485**	Total Capital ($mill)	**5000**
2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	4395.7	**4540**	**4690**	Net Plant ($mill)	**5125**
5.7%	6.0%	6.8%	6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	6.4%	**6.5%**	**6.0%**	Return on Total Cap'l	**6.5%**
8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	**9.0%**	**9.0%**	Return on Shr. Equity	**9.5%**
8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	**9.0%**	**9.0%**	Return on Com Equity E	**9.5%**
4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	4.4%	**4.0%**	**3.5%**	Retained to Com Eq	**3.5%**
46%	41%	36%	41%	43%	46%	50%	53%	53%	54%	**58%**	**59%**	All Div'ds to Net Prof	**63%**

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-.5	+2.6	+.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.63	5.83	5.64
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3299	3422	3392
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.8	+2.0	+2.3
Fixed Charge Cov. (%)	295	329	309

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	2.5%	3.5%	*2.5%*
"Cash Flow"	5.5%	4.0%	*4.0%*
Earnings	7.0%	4.0%	*3.5%*
Dividends	6.5%	10.0%	*7.0%*
Book Value	5.5%	5.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	281.0	315.4	372.0	293.6	1262.0
2017	302.6	333.0	408.3	305.6	1349.5
2018	310.1	340.0	408.8	311.9	1370.8
2019	350.3	316.9	***420***	***312.8***	***1400***
2020	***335***	***350***	***430***	***320***	***1435***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.51	1.12	1.65	.66	3.94
2017	.66	.99	1.80	.77	4.21
2018	.72	1.23	2.02	.52	4.49
2019	.84	1.05	***1.90***	***.66***	***4.45***
2020	***.85***	***1.05***	***2.00***	***.70***	***4.60***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.47	.47	.47	.51	1.92
2016	.51	.51	.51	.55	2.08
2017	.55	.55	.55	.59	2.24
2018	.59	.59	.59	.63	2.40
2019	.63	.63	.63	.67	

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 565,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.2 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 38%; commercial, 22%; industrial, 14%; irrigation, 11%; other, 15%. Generating sources: hydro, 46%; coal, 17%; gas, 8%; purchased, 29%. Fuel costs: 34% of revenues. '18 reported depreciation rate: 2.8%. Has 2,000 employees. Chairman: Richard J. Dahl. President & CEO: Darrel T. Anderson. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

The board of directors of IDACORP raised the dividend. The increase was $0.04 a share (6.3%) quarterly, effective with the fourth-quarter payment. In recent years, the company has had a policy of hiking the disbursement at least 5% annually, to remain near the upper end of its targeted range of 50%-60% for the payout ratio. However, this policy might be about to change. The dividend announcement stated, " . . . we expect to further discuss with the board the appropriate target payout ratio in mid-November." The current target of 50%-60% is lower than that of most utilities, so a boost in this range would not surprise us.

We raised our 2019 share-earnings estimate by a nickel, to $4.45. June-period profits topped out estimate for the quarter by that amount. In addition, IDACORP revised its share-net target for 2019 from $4.30-$4.45 to $4.43-$4.50, so our expectation remains within management's guidance. Our 2020 estimate remains at $4.60 a share.

The company's utility subsidiary, Idaho Power, is benefiting from a vibrant economy in its service territory. For the 12-month period that ended on June 30th, customer growth was 2.5%. The Electric Operating Statistics box on this page shows that this figure is accelerating. Population growth and expansion of businesses and institutions are responsible for this.

If needed, Idaho Power may supplement its income through a regulatory mechanism. The utility may use up to $25 million of accumulated deferred investment tax credits if its return on equity falls below 9.5% (9.4% beginning in 2020). The company does not expect to record any of this income in 2019.

IDACORP stock is priced expensively. The equity is trading at a significant market premium. The dividend yield (even when reflecting the upcoming hike in the payout) is not significantly higher than the median for all dividend-paying stocks under our coverage. Finally, total return potential is unappealing, both for the 18-month time frame and the 2022-2024 period. Perhaps takeover speculation is reflected in the quotation, but we advise against buying the stock hoping for a deal.

Paul E. Debbas, CFA *October 25, 2019*

(A) Diluted EPS. Excl. nonrecurring gains (loss): '03, 26¢; '05, (24¢); '06, 17¢. '17 earnings don't sum due to rounding. Next earnings report due early Nov. **(B)** Dividends historically paid in late Feb., May, Aug., and Nov. ■ Dividend reinvestment plan available. † Shareholder investment plan available. **(C)** Incl. intangibles. In '18: $23.12/sh. **(D)** In millions. **(E)** Rate base: Net original cost. Rate allowed on common equity in '11: 10% (imputed); earned on avg. com. eq., '18: 9.8%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	95
Earnings Predictability	95

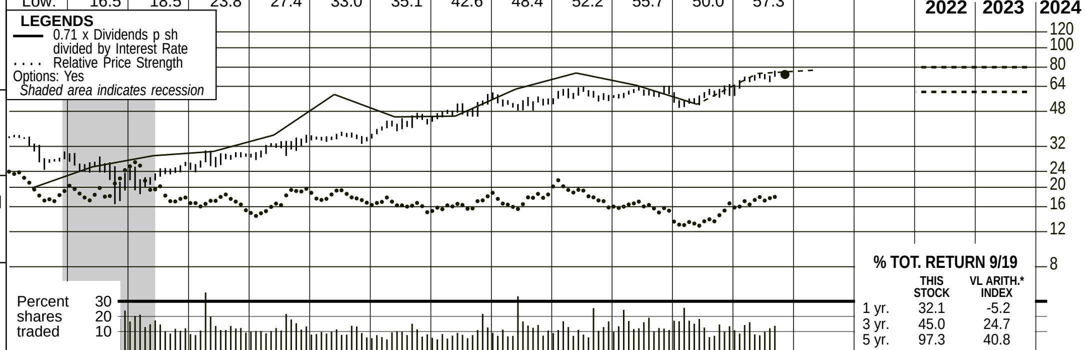
NORTHWESTERN NYSE-NWE

RECENT PRICE **73.34** | P/E RATIO **21.2** (Trailing: 20.7 Median: 16.0) | RELATIVE P/E RATIO **1.25** | DIV'D YLD **3.2%** | **VALUE LINE**

TIMELINESS 3 Lowered 9/6/19
SAFETY 2 Raised 7/27/18
TECHNICAL 2 Raised 10/25/19
BETA .60 (1.00 = Market)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	29.7	26.8	30.6	36.6	38.0	47.2	58.7	59.7	63.8	64.5	65.7	76.7
Low:	16.5	18.5	23.8	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0	57.3

LEGENDS
— 0.71 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2022 | 2023 | 2024

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$56-$78	$67 (-10%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+10%)	6%
Low	60	(-20%)	-1%

Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	118	140	131
to Sell	143	126	145
Hld's(000)	48945	48402	48906

Percent shares traded 30 / 20 / 10

% TOT. RETURN 9/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	32.1	-5.2
3 yr.	45.0	24.7
5 yr.	97.3	40.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
- -	29.18	32.57	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	23.81	*25.25*	*25.65*	Revenues per sh	*28.50*
- -	3.20	4.00	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	6.96	*7.20*	*7.30*	"Cash Flow" per sh	*8.25*
- -	d14.32	1.71	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	3.40	*3.65*	*3.60*	Earnings per sh A	*4.00*
- -	- -	1.00	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	2.20	*2.30*	*2.40*	Div'd Decl'd per sh B ■ †	*2.70*
- -	2.25	2.26	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	5.64	*6.65*	*6.55*	Cap'l Spending per sh	*6.00*
- -	19.92	20.60	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	38.60	*40.30*	*41.40*	Book Value per sh C	*45.00*
- -	35.60	35.79	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	50.32	*50.50*	*50.65*	Common Shs Outst'g D	*51.10*
- -	- -	17.1	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
- -	- -	.91	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	*Value Line*		Relative P/E Ratio	*1.00*
- -	- -	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1141.9	1110.7	1117.3	1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	1198.1	*1275*	*1300*	Revenues ($mill)	*1450*
73.4	77.4	92.6	83.7	94.0	120.7	138.4	164.2	162.7	171.1	*185*	*185*	Net Profit ($mill)	*210*
17.2%	25.0%	9.8%	9.6%	13.2%	- -	13.7%	- -	7.6%	7.6%	*2.5%*	*5.0%*	Income Tax Rate	*10.0%*
4.4%	14.2%	3.3%	9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	3.4%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
56.4%	57.2%	52.2%	53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	52.2%	*51.0%*	*50.0%*	Long-Term Debt Ratio	*48.0%*
43.6%	42.8%	47.8%	46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	*49.0%*	*50.0%*	Common Equity Ratio	*52.0%*
1803.9	1916.4	1797.1	2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	4064.6	*4155*	*4215*	Total Capital ($mill)	*4400*
1964.1	2118.0	2213.3	2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	4521.3	*4680*	*4825*	Net Plant ($mill)	*5150*
6.0%	5.9%	7.0%	5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	5.2%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
3.2%	3.5%	4.7%	3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	3.2%	*3.5%*	*3.0%*	Retained to Com Eq	*3.0%*
66%	63%	56%	65%	61%	54%	65%	58%	62%	64%	*63%*	*66%*	All Div'ds to Net Prof	*66%*

CAPITAL STRUCTURE as of 6/30/19
Total Debt $2180.1 mill. **Due in 5 Yrs** $321.5 mill.
LT Debt $2177.7 mill. **LT Interest** $82.9 mill.
Incl. $18.7 mill. capitalized leases.
(LT interest earned: 2.9x)

Pension Assets-12/18 $525.3 mill.
Oblig $649.6 mill.

Pfd Stock None

Common Stock 50,442,932 shs.
as of 7/19/19

MARKET CAP: $3.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-.7	+3.8	+2.9
Avg. Indust. Use (MWH)	29784	30987	34573
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2138	2133	2173
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.3	+1.2
Fixed Charge Cov. (%)	253	275	275

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-2.5%	-3.0%	*2.0%*
"Cash Flow"	5.5%	5.0%	*3.0%*
Earnings	8.5%	7.0%	*3.0%*
Dividends	5.0%	7.0%	*4.5%*
Book Value	5.5%	8.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	332.5	293.1	301.0	330.6	1257.2
2017	367.3	283.9	309.9	344.6	1305.7
2018	341.5	261.8	279.9	314.9	1198.1
2019	384.2	270.7	*295.1*	*325*	*1275*
2020	*365*	*285*	*310*	*340*	*1300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.82	.73	.92	.92	3.39
2017	1.17	.44	.75	.98	3.34
2018	1.18	.61	.56	1.06	3.40
2019	1.44	.49	*.72*	*1.00*	*3.65*
2020	*1.25*	*.55*	*.75*	*1.05*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.48	.48	.48	.48	1.92
2016	.50	.50	.50	.50	2.00
2017	.525	.525	.525	.525	2.10
2018	.55	.55	.55	.55	2.20
2019	.575	.575	.575		

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 438,000 electric customers in Montana and South Dakota and 289,000 gas customers in Montana (85% of gross margin), South Dakota (14%), and Nebraska (1%). Electric revenue breakdown: residential, 39%; commercial, 46%; industrial, 5%; other, 10%. Generating sources: hydro, 35%; coal, 29%; wind, 6%; other, 4%; purchased, 26%. Fuel costs: 24% of revenues. '18 reported deprec. rate: 3.0%. Has 1,500 employees. Chairman: Stephen P. Adik. President & CEO: Robert C. Rowe. Inc.: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern is awaiting an order in its electric rate case in Montana. The utility filed for a tariff hike of $30.7 million (6.1%), based on a return of 10.65% on a common-equity ratio of 49.4%. The settlement, if approved by the state commission, will boost rates by $6.5 million (1.3%), based on a return of 9.65% on a common-equity ratio of 49.4%. Also, annual depreciation expense will be lowered by $9.3 million. Note that the settlement does not address matters of rate design, such as the subsidization of solar users by nonsolar customers. Also note that NorthWestern has been collecting an interim rate hike of $10.5 million (subject to refund) since April 1st. A decision from the Montana regulators is expected within the next few weeks.

We trimmed our 2019 share-earnings estimate by a nickel, but NorthWestern should turn in a record tally anyway. June-quarter profits fell short of our estimate due to mild weather patterns. However, weather conditions were favorable in the first period. Accordingly, March-quarter earnings were much higher than usual. Rate relief and solid customer growth are positive factors. Note that NorthWestern isn't providing earnings guidance while the aforementioned rate case is pending.

We expect a slight earnings decline in 2020. This is based on our assumption of a return to normal winter weather. We also assume that the Montana rate settlement is approved along the lines mentioned above.

The utility filed an electricity supply resource plan in Montana. NorthWestern estimates it will need dispatchable peaking capacity (150 to 250 megawatts) by 2022. The company expects to issue a request for proposals by yearend 2019. The state commission will provide comments on NorthWestern's plan. Note that the company also has a plan in South Dakota, and will make a project selection in November.

NorthWestern stock has a dividend yield that is average for a utility. However, we expect total returns over the 18-month period will be negative. For the 3- to 5-year period, projected total returns are low.

Paul E. Debbas, CFA *October 25, 2019*

(A) Diluted EPS. Excl. gain (loss) on disc. ops.: '05, (6¢); '06, 1¢; nonrec. gains: '12, 39¢ net; '15, 27¢; '18, 52¢; '19, 45¢. '18 EPS don't sum due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '18: $15.80/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '14 (elec.): 9.8%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%; earned on avg. com. eq., '18: 9.2%. Regul. Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	85

OGE ENERGY CORP. NYSE-OGE

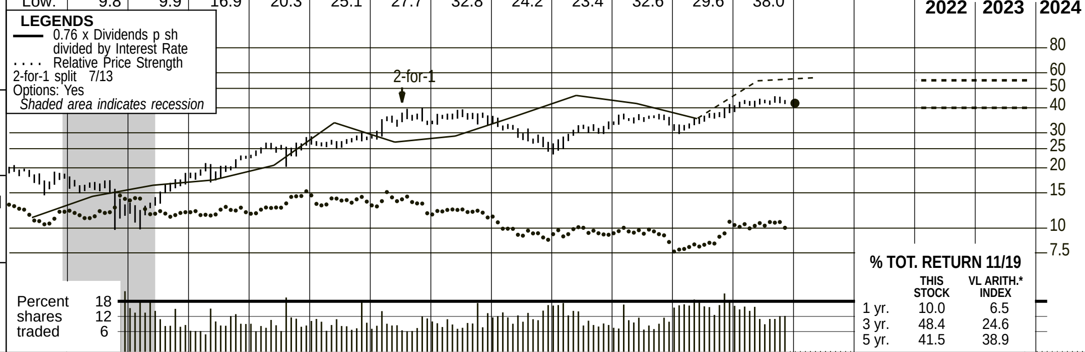
RECENT PRICE 42.11 | P/E RATIO 17.8 (Trailing: 18.6 / Median: 17.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 2 Raised 11/29/19
SAFETY 2 Lowered 12/18/15
TECHNICAL 1 Raised 12/6/19
BETA .75 (1.00 = Market)

High:	18.1	18.9	23.1	28.6	30.1	40.0	39.3	36.5	34.2	37.4	41.8	45.8
Low:	9.8	9.9	16.9	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6	38.0

Target Price Range 2022 2023 2024

LEGENDS
— 0.76 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/13
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$39-$50	$45 (5%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	10%
Low	40	(-5%)	3%

Institutional Decisions

	1Q2019	2Q2019	3Q2019
to Buy	234	184	177
to Sell	175	225	209
Hld's(000)	136796	134414	132772

% TOT. RETURN 11/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.0	6.5
3 yr.	48.4	24.6
5 yr.	41.5	38.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
21.62	27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	11.37	**11.50**	**12.25**	Revenues per sh	**14.50**
1.82	1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.74	**4.00**	**4.10**	"Cash Flow" per sh	**5.00**
.87	.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.12	**2.25**	**2.30**	Earnings per sh A	**2.75**
.67	.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	**1.51**	**1.57**	Div'd Decl'd per sh B ■	**1.85**
1.04	1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	2.87	**3.20**	**2.90**	Cap'l Spending per sh	**3.75**
6.87	7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	20.06	**20.70**	**21.45**	Book Value per sh C	**24.00**
174.80	180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	**200.00**	**200.00**	Common Shs Outst'g D	**200.00**
11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	**17.0**
.67	.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	*Value Line*		Relative P/E Ratio	**.95**
6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	4.0%	*estimates*		Avg Ann'l Div'd Yield	**4.0%**

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
2869.7	3716.9	3915.9	3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	2270.3	**2300**	**2450**	Revenues ($mill)	**2900**
258.3	295.3	342.9	355.0	387.6	395.8	337.6	338.2	384.3	425.5	**450**	**460**	Net Profit ($mill)	**550**
31.7%	34.9%	30.7%	26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	14.5%	**6.0%**	**6.0%**	Income Tax Rate	**6.0%**
9.1%	5.7%	9.0%	2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	8.3%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**1.0%**
50.6%	50.8%	51.6%	50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	42.0%	**43.5%**	**44.0%**	Long-Term Debt Ratio	**45.0%**
49.4%	49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	**56.5%**	**56.0%**	Common Equity Ratio	**55.0%**
4129.7	4652.5	5300.4	5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	6902.0	**7340**	**7685**	Total Capital ($mill)	**8725**
5911.6	6464.4	7474.0	8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	8643.8	**8935**	**9145**	Net Plant ($mill)	**10150**
7.9%	7.8%	7.8%	7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	7.3%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.5%**
12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	**11.0%**	**10.5%**	Return on Shr. Equity	**11.5%**
12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	**11.0%**	**10.5%**	Return on Com Equity E	**11.5%**
6.0%	6.7%	7.7%	7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	3.8%	**3.5%**	**3.5%**	Retained to Com Eq	**4.0%**
53%	48%	43%	44%	43%	47%	61%	67%	64%	64%	**66%**	**68%**	All Div'ds to Net Prof	**67%**

CAPITAL STRUCTURE as of 9/30/19
Total Debt $3363.5 mill. **Due in 5 Yrs** $169.3 mill.
LT Debt $3194.7 mill. **LT Interest** $132.0 mill.
(LT interest earned: 4.4x)

Leases, Uncapitalized Annual rentals $22.1 mill.

Pension Assets-12/18 $522.8 mill. **Oblig** $615.9 mill.

Pfd Stock None

Common Stock 200,176,215 shs.

MARKET CAP: $8.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-1.1	-2.2	+6.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.17	5.30	4.86
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6538	6456	6863
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.0	+.9
Fixed Charge Cov. (%)	336	315	292

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-6.0%	-8.5%	4.0%
"Cash Flow"	4.0%	- -	6.5%
Earnings	4.0%	1.0%	6.5%
Dividends	6.5%	9.5%	6.5%
Book Value	7.5%	6.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	433.1	551.4	743.9	530.8	2259.2
2017	456.0	586.4	716.8	501.9	2261.1
2018	492.7	567.0	698.8	511.8	2270.3
2019	490.0	513.7	755.4	**540.9**	**2300**
2020	**525**	**550**	**800**	**575**	**2450**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.13	.35	.92	.29	1.69
2017	.18	.52	.92	.30	1.92
2018	.27	.55	1.02	.27	2.12
2019	.24	.50	1.25	**.26**	**2.25**
2020	**.25**	**.60**	**1.15**	**.30**	**2.30**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.25	.25	.25	.275	1.03
2016	.275	.275	.275	.3025	1.13
2017	.3025	.3025	.3025	.3325	1.24
2018	.3325	.3325	.3325	.365	1.36
2019	.365	.365	.365	.3875	

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 856,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 25.5% of Enable Midstream Partners. Electric revenue breakdown: residential, 40%; commercial, 26%; industrial, 9%; oilfield, 7%; other, 18%. Generating sources: coal, 28%; gas, 27%; wind, 4%; purchased, 41%. Fuel costs: 39% of revenues. '18 reported depreciation rate (utility): 2.7%. Has 2,300 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Telephone: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary received a rate order from the Oklahoma commission. The regulators approved a settlement calling for an increase of $76.4 million for Oklahoma Gas and Electric, based on a 9.5% return on a 53% common-equity ratio. New tariffs were retroactive to July 1st.

A regulatory filing is pending in Arkansas. OG&E requested a $5.9 million increase under the state's formula rate plan. New rates are expected to be in place at the start of April.

We raised our 2019 earnings estimate by $0.15 a share, to $2.25. Third-quarter profits benefited from a hotter-than-usual summer. The tariff increase was another positive factor. Our estimate is within the company's targeted range of $2.24-$2.30 a share, up from $2.05-$2.20 previously.

We estimate a slight earnings increase in 2020. The company will benefit from a full year of rate relief for OG&E in Oklahoma and a partial year in Arkansas. Load growth trends are favorable, as well. On the other hand, we assume normal weather patterns in the third quarter, versus the favorable ones in 2019.

The company raised its long-term capital budget. OG&E has begun a program to modernize the electric grid in Arkansas, and plans to follow suit in Oklahoma. The utility will recover these costs in Arkansas through the state's formula rate plan, and would like recovery in Oklahoma through a rider (surcharge) on customers' bills. OG&E plans to put forth such a request in early 2020. Note that the company expects to meet its capital needs without issuing common equity.

The board of directors raised the dividend, effective with the payment in October. The increase was $0.09 a share (6.2%). Subsequent dividend hikes are expected to be in a range of 4%-6%, similar to OGE Energy's goal for earnings growth. The company benefits from the distributions ($147 million annually) it receives through its 25.5% stake in Enable Midstream Partners, a natural gas master limited partnership.

The timely stock's dividend yield is slightly above the utility average. Total return potential for the 18-month and 3- to 5-year periods is unexceptional.

Paul E. Debbas, CFA *December 13, 2019*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '03, (7¢); '04, (3¢); '15, (33¢); '17, $1.18; gains on discont. ops.: '02, 6¢; '05, 25¢; '06, 20¢. '18 EPS don't sum due to rounding. Next earnings report due late Feb. **(B)** Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges. In '18: $1.43/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '18: 10.8%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	80

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE **49.16** | P/E RATIO **22.3** (Trailing: 24.3 / Median: 22.0) | RELATIVE P/E RATIO **1.29** | DIV'D YLD **3.0%** | VALUE LINE

High:	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4	42.6	48.7	51.9	57.7
Low:	15.0	15.5	18.2	17.5	20.7	25.2	26.5	24.8	25.8	35.7	39.0	45.9

TIMELINESS 3 Lowered 3/1/19
SAFETY 2 Raised 6/17/16
TECHNICAL 2 Raised 11/22/19
BETA .70 (1.00 = Market)

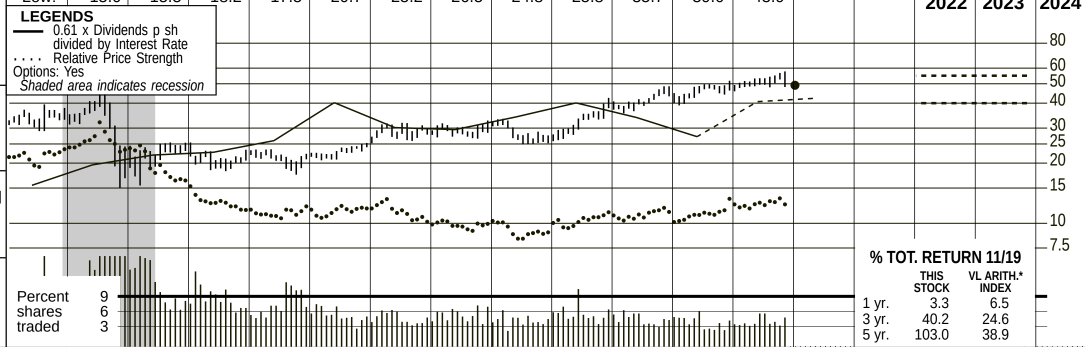
18-Month Target Price Range
Low-High: $44-$68 — Midpoint (% to Mid): $56 (15%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+10%)	6%
Low	40	(-20%)	-1%

Institutional Decisions

	1Q2019	2Q2019	3Q2019
to Buy	83	78	88
to Sell	62	75	61
Hld's(000)	17362	17859	18133



% TOT. RETURN 11/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.3	6.5
3 yr.	40.2	24.6
5 yr.	103.0	38.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	20.60	20.42	21.47	23.10	*23.15*	*23.50*	Revenues per sh	*27.00*
3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	3.44	3.70	3.96	*4.05*	*4.15*	"Cash Flow" per sh	*4.75*
1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	1.56	1.60	1.86	2.06	*2.15*	*2.25*	Earnings per sh A	*2.50*
1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	1.25	1.28	1.34	*1.40*	*1.46*	Div'd Decl'd per sh B ■	*1.65*
1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	4.10	3.36	2.66	*5.85*	*9.05*	Cap'l Spending per sh	*3.50*
12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	17.62	18.38	*19.25*	*21.00*	Book Value per sh C	*23.25*
25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	39.35	39.56	39.66	*40.00*	*41.50*	Common Shs Outst'g D	*41.80*
17.8	17.3	15.4	17.3	19.0	30.1	31.2	NMF	NMF	21.7	21.1	18.8	18.2	20.2	22.1	22.2	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
1.01	.91	.82	.93	1.01	1.81	2.08	NMF	NMF	1.38	1.19	.99	.92	1.06	1.11	1.19	*Value Line*		Relative P/E Ratio	*1.05*
4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	3.9%	3.1%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/19
Total Debt $699.2 mill. **Due in 5 Yrs** $280.5 mill.
LT Debt $590.0 mill. **LT Interest** $28.8 mill.
(LT interest earned: 4.2x)

Leases, Uncapitalized Annual rentals $6.2 mill.
Pension Assets-12/18 $269.8 mill. **Oblig** $328.4 mill.

Pfd Stock None

Common Stock 39,759,054 shs. **as of 10/31/19**
MARKET CAP: $2.0 billion (Mid Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1039.5	1119.1	1077.9	859.2	893.3	799.3	779.8	803.5	849.4	916.4	*925*	*975*	Revenues ($mill)	*1125*
26.0	13.6	16.4	39.0	50.2	56.9	58.6	62.0	73.9	82.3	*85.0*	*90.0*	Net Profit ($mill)	*105*
- -	- -	14.5%	5.2%	21.3%	22.5%	27.0%	24.5%	25.5%	15.0%	*18.0%*	*19.0%*	Income Tax Rate	*18.0%*
4.0%	.6%	3.8%	1.7%	5.6%	3.9%	3.5%	2.2%	2.3%	4.1%	*6.0%*	*9.0%*	AFUDC % to Net Profit	*4.0%*
38.8%	40.2%	44.6%	44.0%	42.1%	46.5%	42.4%	43.0%	41.3%	44.7%	*47.5%*	*50.0%*	Long-Term Debt Ratio	*50.5%*
59.8%	58.4%	54.0%	54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	*52.5%*	*50.0%*	Common Equity Ratio	*49.5%*
1124.4	1083.3	1058.9	959.2	924.4	1071.3	1051.0	1175.4	1187.3	1318.9	*1460*	*1745*	Total Capital ($mill)	*1975*
1098.6	1108.7	1077.5	1049.5	1167.0	1268.5	1387.8	1477.2	1539.6	1581.1	*1735*	*2035*	Net Plant ($mill)	*2250*
3.4%	2.7%	3.2%	5.7%	6.8%	6.7%	6.8%	6.5%	7.3%	7.3%	*7.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
3.8%	2.1%	2.8%	7.3%	9.4%	9.9%	9.7%	9.3%	10.6%	11.3%	*11.0%*	*10.5%*	Return on Shr. Equity E	*11.0%*
3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	9.7%	9.3%	10.6%	11.3%	*11.0%*	*10.5%*	Return on Com Equity	*11.0%*
NMF	NMF	NMF	NMF	1.2%	2.2%	2.0%	2.1%	3.3%	4.0%	*4.0%*	*4.0%*	Retained to Com Eq	*3.5%*
NMF	NMF	NMF	113%	87%	78%	79%	78%	69%	65%	*65%*	*64%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+3.4	+1.4	+3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.24	6.26	5.97
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	903	917	912
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.5	+.2
Fixed Charge Cov. (%)	512	608	409

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-5.5%	-3.5%	*3.5%*
"Cash Flow"	1.5%	6.5%	*4.5%*
Earnings	2.0%	14.0%	*5.0%*
Dividends	1.0%	1.5%	*4.0%*
Book Value	- -	3.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	206.2	203.5	197.2	196.6	803.5
2017	214.1	212.1	216.5	206.7	849.4
2018	241.2	226.3	227.7	221.2	916.4
2019	246.0	229.2	228.7	*221.1*	*925*
2020	*250*	*240*	*245*	*240*	*975*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.38	.41	.37	.44	1.60
2017	.49	.42	.45	.50	1.86
2018	.66	.47	.58	.35	2.06
2019	.66	.39	.62	*.48*	*2.15*
2020	*.68*	*.42*	*.65*	*.50*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.3075	.3075	.3075	.3075	1.23
2016	.3125	.3125	.3125	.3125	1.25
2017	.32	.32	.32	.32	1.28
2018	.335	.335	.335	.335	1.34
2019	.35	.35	.35	.35	

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to 132,000 customers in Minnesota (53% of retail electric revenues), North Dakota (38%), and South Dakota (9%). Electric rev. breakdown: residential, 32%; commercial & farms, 37%; industrial, 30%; other, 1%. Generating sources: coal, 53%; other, 10%; purchased, 37%. Fuel costs: 15% of revenues. Also has operations in manufacturing and plastics (34% of '18 income). '18 reported deprec. rate (utility): 2.8%. Has 2,300 employees. Chairman: Nathan I. Partain. President & CEO: Charles S. MacFarlane. Incorporated: Minnesota. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Tel.: 866-410-8780. Internet: www.ottertail.com.

Otter Tail Corporation's stock price has lagged the performance of most electric utility issues in 2019. The quotation has declined slightly in a year that has seen the prices of many equities in this industry climb more than 10%. We think the market is concerned about the prospects of Otter Tail's nonutility businesses, which generate roughly 25% of corporate profits. The Plastics division continues to face weaker demand and lower margins, consistent with management's expectation in early 2019. However, the Manufacturing segment's prospects have worsened as the year has progressed, due to weaker demand and a downturn in the scrap metal market. When Otter Tail issued its 2019 earnings guidance in February, the company expected Manufacturing profits to wind up several cents a share above the $0.32 posted in 2018. Now, the expectation is for flat income. As a result, Otter Tail revised its 2019 share-earnings target from $2.10-$2.25 to $2.10-$2.20. Our estimate remains $2.15. (The fourth-quarter comparison is easy because last year some unusual items lowered share net by $0.13.)

Otter Tail Power Company is faring well. The utility is benefiting from a $2.6 million (7.7%) rate hike that took effect at the start of August. Some of its capital spending is recovered through riders on customers' bills. We think growth in utility income will enable profits to advance to $2.25 a share in 2020, despite the tough conditions at the nonutility operations.

Two sizable projects are under construction. The utility's largest project ever is a 150-megawatt wind farm, which is expected to come on line in late 2020 at a cost of $258 million. Otter Tail is building a 245-mw gas-fired plant at a cost of $158 million, which is expected to be on line in 2021.

We expect a dividend increase in the first quarter of 2020. This is the normal timing of the hike. We look for a raise of $0.06 a share (4.3%) in the annual disbursement. Otter Tail is looking to maintain a payout ratio in a range of 60%-70%.

The stock's dividend yield is about average for a utility. The equity is much more attractive for the 18-month span than for the 3- to 5-year period.

Paul E. Debbas, CFA *December 13, 2019*

(A) Diluted earnings. Excl. nonrec. gains (loss): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from disc. ops.: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢; '17, 1¢. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '18: $4.67/sh. (D) In mill. (E) Rate all'd on com. eq. in MN in '17: 9.41%; in ND in '18: 9.77%; in SD in '19: 8.75%; earned on avg. com. eq., '18: 11.5%. Regulat. Clim.: MN, ND, Average; SD, Above Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	65

PINNACLE WEST NYSE-PNW

RECENT PRICE 93.66 | P/E RATIO 20.2 (Trailing: 21.0 Median: 15.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Lowered 8/30/19
SAFETY 1 Raised 5/3/13
TECHNICAL 2 Raised 10/25/19
BETA .55 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$82-$115 $99 (5%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+15%)	7%
Low	90	(-5%)	3%

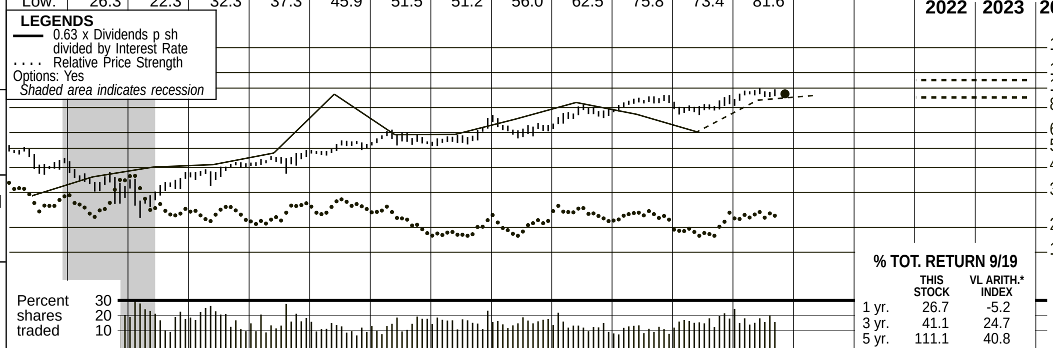
Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	256	261	266
to Sell	192	209	188
Hld's(000)	95077	95676	100901

	2012	2013	2014	2015	2016	2017	2018	2019
High:	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3
Low:	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0

High:	82.8	92.5	92.6	99.8
Low:	62.5	75.8	73.4	81.6

Target Price Range 2022 2023 2024



% TOT. RETURN 9/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.7	-5.2
3 yr.	41.1	24.7
5 yr.	111.1	40.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	31.90	32.93	31.60	34.20	Revenues per sh	39.00
7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.79	11.41	11.55	12.20	"Cash Flow" per sh	14.25
2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	4.43	4.54	4.75	5.05	Earnings per sh A	5.75
1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	2.87	3.04	3.22	Div'd Decl'd per sh B ■	3.80
7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	12.80	10.73	11.25	11.05	Cap'l Spending per sh	11.75
31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	44.80	46.59	48.25	50.05	Book Value per sh C	55.75
91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	111.75	112.10	112.30	112.50	Common Shs Outst'g D	114.00
14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	19.3	17.8	Bold figures are		Avg Ann'l P/E Ratio	17.5
.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	.98	.97	.96	Value Line		Relative P/E Ratio	.95
4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%	3.5%	estimates		Avg Ann'l Div'd Yield	3.8%
						3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	3495.4	3498.7	3565.3	3691.2	3550	3850	Revenues ($mill)	4450
						229.2	330.4	328.2	387.4	406.1	397.6	437.3	442.0	497.8	511.0	540	575	Net Profit ($mill)	670
						36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	34.3%	33.9%	32.5%	20.2%	10.0%	10.0%	Income Tax Rate	10.0%
						11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	11.8%	14.1%	13.9%	15.2%	7.0%	7.0%	AFUDC % to Net Profit	7.0%
						50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	43.0%	45.6%	48.9%	47.0%	48.5%	47.5%	Long-Term Debt Ratio	44.5%
						49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	57.0%	54.4%	51.1%	53.0%	51.5%	52.5%	Common Equity Ratio	55.5%
						6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	8046.3	8825.4	9796.4	9861.1	10500	10725	Total Capital ($mill)	11450
						9257.8	9578.8	9962.3	10396	10889	11194	11809	12714	13445	14030	14525	14975	Net Plant ($mill)	16500
						4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	6.4%	6.0%	6.1%	6.2%	6.0%	6.5%	Return on Total Cap'l	7.0%
						6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	10.0%	10.0%	Return on Shr. Equity	10.5%
						6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	9.8%	10.0%	10.0%	Return on Com Equity E	10.5%
						.7%	3.1%	2.8%	4.1%	4.1%	3.5%	3.9%	3.5%	4.2%	3.9%	3.5%	4.0%	Retained to Com Eq	4.0%
						89%	66%	68%	58%	58%	62%	59%	62%	58%	60%	63%	63%	All Div'ds to Net Prof	64%

CAPITAL STRUCTURE as of 6/30/19
Total Debt $5569.3 mill. **Due in 5 Yrs** $1382.3 mill.
LT Debt $4886.9 mill. **LT Interest** $193.9 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $13.8 mill.
Pension Assets-12/18 $2733.5 mill.
Oblig $3190.6 mill.
Pfd Stock None

Common Stock 112,303,854 shs.
as of 8/1/19
MARKET CAP: $11 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+.3	- -	-.3
Avg. Indust. Use (MWH)	640	620	662
Avg. Indust. Revs. per KWH (¢)	8.37	8.34	8.40
Capacity at Peak (Mw)	9192	8438	8643
Peak Load, Summer (Mw)	7051	7363	7320
Annual Load Factor (%)	48.0	46.3	47.0
% Change Customers (yr-end)	+1.3	+1.8	+2.0
Fixed Charge Cov. (%)	416	425	318

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-.5%	1.0%	3.5%
"Cash Flow"	1.0%	5.5%	5.5%
Earnings	4.5%	5.0%	5.0%
Dividends	2.5%	3.0%	6.0%
Book Value	2.5%	4.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	677.2	915.4	1166.9	739.2	3498.7
2017	677.7	944.6	1183.3	759.7	3565.3
2018	692.7	974.1	1268.0	756.4	3691.2
2019	740.5	869.5	1200	740	3550
2020	700	1050	1300	800	3850

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.04	1.08	2.35	.47	3.95
2017	.21	1.49	2.46	.27	4.43
2018	.03	1.48	2.80	.23	4.54
2019	.16	1.28	3.05	.26	4.75
2020	.05	1.55	3.15	.30	5.05

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.595	.595	.595	.625	2.41
2016	.625	.625	.625	.655	2.53
2017	.655	.655	.655	.695	2.66
2018	.695	.695	.695	.7375	2.82
2019	.7375	.7375			

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.3 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 51%; commercial, 39%; industrial, 5%; other, 5%. Generating sources: nuclear, 28%; gas & other, 26%; coal, 24%; purchased, 22%. Fuel costs: 29% of revenues. '18 reported deprec. rate: 2.8%. Has 6,300 employees. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary is about to file a general rate case. Arizona Public Service wasn't planning to file an application until June 1, 2020, but the Arizona Corporation Commission (ACC) directed the utility to do so by October 31, 2019. We do not know how much APS will request, but significant matters concerning rate design are not expected to be part of the upcoming petition. When an order will be issued is unknown, but this case won't have much (if any) effect on the company's earnings until 2021.

The utility is still awaiting an order on another regulatory matter. APS requested a $67.5 million "step" increase to recover the cost of an environmental upgrade to a coal-fired plant. The ACC's staff and an administrative law judge recommended a $58.5 million increase, which the company found acceptable. However, the ACC still has not issued an order (one was initially expected several months ago), and there is no telling when it will do so. In fact, it is not out of the question that this matter will be combined with the upcoming rate case.

We reduced our 2019 share-earnings estimate by $0.10. It appears as if APS will not get any rate relief this year for the aforementioned environmental upgrade. This will hurt the bottom line by $0.07 a share. The utility's service area also experienced milder-than-normal weather conditions in the second quarter. (On the other hand, August was hotter than usual.) Our revised share-net estimate is at the bottom end of Pinnacle West's targeted range of $4.75-$4.95. Note that management is guiding Wall Street to the lower end of this range.

As this report went to press, we were expecting an announcement of a dividend increase. We estimate that the board will boost the annual disbursement by $0.18 a share (6.1%). Pinnacle West is targeting 6% yearly dividend growth.

This high-quality stock has a dividend yield that is average, by utility standards. The equity is expected to produce total returns that are respectable over 18 months, but just modest over the 3- to 5-year period. Like most utility issues, the recent quotation is within our 2022-2024 Target Price Range.

Paul E. Debbas, CFA *October 25, 2019*

(A) Diluted EPS. Excl. nonrec. gain (loss): '09, ($1.45); '17, 8¢; gains (losses) from disc. ops.: '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '16 EPS don't sum due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '18: $14.34/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '17: 10.0%; earned on avg. com. eq., '17: 10.0%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	95

PNM RESOURCES NYSE-PNM

RECENT PRICE 50.65 | P/E RATIO 24.6 (Trailing: 32.3 Median: 18.0) | RELATIVE P/E RATIO 1.46 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 3 Lowered 9/13/19
SAFETY 3 Lowered 5/9/08
TECHNICAL 3 Lowered 10/11/19
BETA .60 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$38-$57 $48 (-5%)

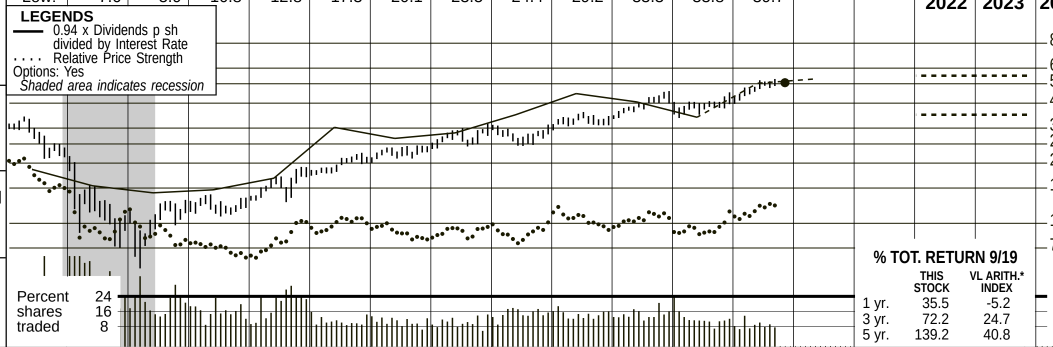
2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+10%)	5%
Low	35	(-30%)	-5%

Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	116	118	105
to Sell	141	142	124
Hld's(000)	71732	71900	72648

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	21.7	13.1	14.0	19.2	22.5	24.5	31.6	31.2	36.2	46.0	45.3	53.0
Low:	7.6	5.9	10.8	12.8	17.3	20.1	23.5	24.4	29.2	33.3	33.8	39.7



% TOT. RETURN 9/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	35.5	-5.2
3 yr.	72.2	24.7
5 yr.	139.2	40.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	18.14	18.04	*18.50*	*19.15*	Revenues per sh	*21.00*
3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	5.30	5.13	*5.65*	*5.95*	"Cash Flow" per sh	*6.75*
1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	1.92	1.66	*2.15*	*2.25*	Earnings per sh A	*2.50*
.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	1.09	*1.18*	*1.24*	Div'd Decl'd per sh B ■ †	*1.50*
2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	6.28	6.29	*7.95*	*8.65*	Cap'l Spending per sh	*7.75*
17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	21.28	21.20	*20.75*	*22.05*	Book Value per sh C	*26.50*
60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	79.65	79.65	*79.65*	*81.00*	Common Shs Outst'g D	*85.00*
14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	20.4	23.4	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	1.03	1.26	*Value Line*		Relative P/E Ratio	*1.00*
3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	3.0%	2.8%	2.5%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 6/30/19
Total Debt $3168.0 mill. **Due in 5 Yrs** $1217.1 mill.
LT Debt $2771.9 mill. **LT Interest** $126.0 mill.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $31.8 mill.
Pension Assets-12/18 $545.0 mill.
Oblig $624.8 mill.
Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par without mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 7/26/19
MARKET CAP: $4.0 billion (Mid Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	1439.1	1363.0	1445.0	1436.6	*1475*	*1550*	Revenues ($mill)	*1775*
54.0	80.5	97.1	106.1	114.0	116.8	118.8	117.4	154.4	133.4	*185*	*200*	Net Profit ($mill)	*235*
30.4%	32.6%	38.8%	31.4%	31.6%	34.8%	36.9%	32.4%	33.0%	13.8%	*21.0%*	*23.0%*	Income Tax Rate	*23.0%*
6.3%	7.1%	8.7%	7.1%	1.3%	10.7%	17.0%	11.0%	11.9%	14.5%	*13.0%*	*10.0%*	AFUDC % to Net Profit	*9.0%*
48.7%	50.4%	51.5%	50.9%	50.0%	47.8%	54.1%	55.7%	56.1%	61.1%	*60.0%*	*53.5%*	Long-Term Debt Ratio	*57.5%*
51.0%	49.2%	48.1%	48.7%	49.7%	51.9%	45.5%	44.0%	43.6%	38.6%	*40.0%*	*46.0%*	Common Equity Ratio	*42.0%*
3214.9	3100.3	3245.6	3277.9	3344.0	3437.1	3633.3	3806.8	3887.5	4370.0	*4150*	*3875*	Total Capital ($mill)	*5325*
3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	4535.4	4904.7	4980.2	5234.6	*5480*	*5880*	Net Plant ($mill)	*7100*
3.2%	4.2%	4.5%	5.1%	5.2%	5.1%	4.8%	4.7%	5.3%	4.3%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.0%*
3.3%	5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.0%	7.8%	*10.5%*	*10.0%*	Return on Shr. Equity	*9.5%*
3.3%	5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.1%	7.9%	*10.5%*	*10.0%*	Return on Com Equity E	*9.5%*
.5%	2.2%	3.3%	3.8%	3.8%	3.2%	3.3%	2.8%	4.5%	2.9%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
86%	57%	47%	43%	45%	51%	54%	61%	51%	64%	*55%*	*54%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-.5	+.3	+7.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2791	2580	2661
Peak Load, Summer (Mw)	1908	1843	1885
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.8	+1.1
Fixed Charge Cov. (%)	202	243	218

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-4.0%	-1.0%	*3.0%*
"Cash Flow"	6.5%	8.0%	*5.0%*
Earnings	7.0%	6.0%	*7.0%*
Dividends	2.5%	11.0%	*7.0%*
Book Value	- -	1.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	311.0	315.4	400.4	336.2	1363.0
2017	330.2	362.3	419.9	332.6	1445.0
2018	317.9	352.3	422.7	343.7	1436.6
2019	349.6	330.2	*440*	*355.2*	*1475*
2020	*355*	*380*	*455*	*360*	*1550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.13	.34	.68	.31	1.46
2017	.29	.47	.92	.25	1.92
2018	.19	.48	1.09	d.10	1.66
2019	.23	.35	*1.23*	*.34*	*2.15*
2020	*.14*	*.53*	*1.28*	*.30*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.20	.20	.20	.20	.80
2016	.22	.22	.22	.22	.88
2017	.242	.242	.243	.243	.97
2018	.265	.265	.265	.265	1.06
2019	.29	.29	.29		

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 528,000 customers in north central New Mexico, incl. Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 253,000 customers in Texas. Electric revenue breakdown: residential, 39%; commercial, 36%; industrial, 5%; other, 20%. Generating sources not available. Fuel costs: 28% of revenues. '18 reported deprec. rates: 2.4%-8.2%. Has 1,700 employees. Chairman, President & CEO: Patricia K. Collawn. Incorporated: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, New Mexico 87102-3289. Telephone: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources' utility in New Mexico has filed a proposal to abandon a coal-fired plant and recover the costs through the issuance of securitized bonds. Public Service of New Mexico would abandon the plant in mid-2022, when a coal-supply contract expires. Under a new state law, the utility would issue $361 million in securitized bonds. To replace the plant's output, PNM would spend $298 million to add 280 megawatts of gas-fired capacity and 70 mw of battery storage. A third party would provide 350 mw of solar capacity and 60 mw of battery storage. However, the commission — over the objections of the legislature and governor — bifurcated the proceedings so that these matters are evaluated separately. This means the state law wouldn't necessarily apply to the abandonment of the plant. PNM sought clarification from the state supreme court, but the court declined to rule on this matter. (The controversy is the latest example of the state's subpar regulatory climate.) A ruling on abandonment and securitization is expected by April of 2020, and a ruling on replacement power is expected by October of 2020.

Earnings will almost certainly be much higher in 2019. Unrealized losses on investment securities hurt the bottom line by $0.17 a share in the fourth quarter of 2018, making the comparison easy. On the other hand, these gains helped share net by $0.12 in the first six months of 2019. The company is also benefiting from rate relief at PNM and its utility in Texas, TNMP. Our 2019 earnings estimate of $2.15 a share is above the company's guidance of $2.05-$2.11 because the $0.12 gain is excluded from this range.

We expect further growth in 2020. Second-quarter earnings in 2019 were hurt by unusually mild weather in May. We assume normal weather conditions in our 2020 estimate.

This stock is expensively priced. The yield isn't significantly above the median of all dividend-paying stocks under our coverage, even though we reflect an estimated $0.06-a-share (5.2%) hike in the annual payout at the board meeting in December. Potential total returns are not appealing, either for the 18-month span or the 3- to 5-year period.

Paul E. Debbas, CFA *October 25, 2019*

(A) Dil. EPS. Excl. nonrec. gain (losses): '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢); '18, (59¢); 2Q '19, ($1.30). Excl. gains from disc. ops.: '08, 42¢; '09, 78¢. '17 EPS don't sum due to rounding. Next egs. report due early Nov. (B) Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinv. plan avail. (C) Incl. intang. In '18: $12.15/sh. (D) In mill., adj. for split. (E) Rate base: net orig. cost. Rate all'd on com. eq. in NM in '18: 9.575%; in TX in '11: 10.125%; earned on avg. com. eq., '18: 7.7%. Regulatory Climate: NM, Below Avg.; TX, Avg.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	90
Earnings Predictability	75

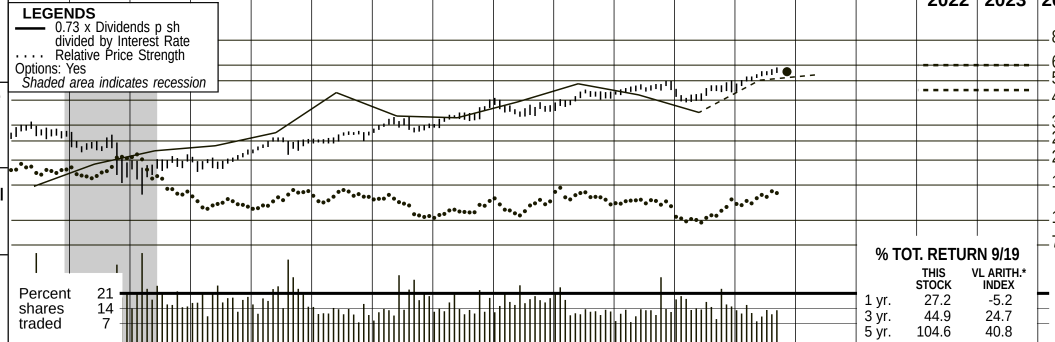
PORTLAND GENERAL NYSE-POR

RECENT PRICE 55.67 | P/E RATIO 22.9 (Trailing: 24.9 Median: 16.0) | RELATIVE P/E RATIO 1.36 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 10/11/19
SAFETY 2 Raised 5/4/12
TECHNICAL 2 Raised 10/18/19
BETA .60 (1.00 = Market)

High:	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0	45.2	50.1	50.4	58.4
Low:	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0	35.3	42.4	39.0	44.0

LEGENDS
—— 0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2022 | 2023 | 2024

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$44-$62	$53 (-5%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+10%)	5%
Low	45	(-20%)	-2%

Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	168	164	142
to Sell	130	156	170
Hld's(000)	84868	84364	84749

Percent shares traded 21 / 14 / 7

% TOT. RETURN 9/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.2	-5.2
3 yr.	44.9	24.7
5 yr.	104.6	40.8

2003	2004	2005F	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
- -	- -	23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.30	*23.75*	*24.00*	Revenues per sh	*27.25*
- -	- -	4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.65	*7.00*	*7.45*	"Cash Flow" per sh	*8.75*
- -	- -	1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.37	*2.40*	*2.55*	Earnings per sh A	*3.00*
- -	- -	- -	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.43	*1.52*	*1.62*	Div'd Decl'd per sh B ■ †	*1.95*
- -	- -	4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.67	*7.10*	*8.30*	Cap'l Spending per sh	*5.75*
- -	- -	19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	28.07	*28.90*	*29.80*	Book Value per sh C	*32.50*
- -	- -	62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.27	*89.40*	*89.55*	Common Shs Outst'g D	*90.00*
- -	- -	- -	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	18.4	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
- -	- -	- -	1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	*Value Line*		Relative P/E Ratio	*.95*
- -	- -	- -	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 6/30/19
Total Debt $2394 mill. **Due in 5 Yrs** $177 mill.
LT Debt $2377 mill. **LT Interest** $119 mill.
Incl. $47 mill. capitalized leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $15 mill.
Pension Assets-12/18 $546 mill. **Oblig** $811 mill.
Pfd Stock None

Common Stock 89,371,751 shs.
as of 7/26/19

MARKET CAP: $5.0 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	1991.0	*2125*	*2150*	Revenues ($mill)	*2450*
95.0	125.0	147.0	141.0	137.0	175.0	172.0	193.0	204.0	212.0	*215*	*230*	Net Profit ($mill)	*265*
28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	7.4%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	8.0%	*7.0%*	*9.0%*	AFUDC % to Net Profit	*6.0%*
50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	46.5%	*50.0%*	*48.0%*	Long-Term Debt Ratio	*49.5%*
49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	53.5%	*50.0%*	*52.0%*	Common Equity Ratio	*50.5%*
3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	4684.0	*5195*	*5115*	Total Capital ($mill)	*5775*
3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	6887.0	*7110*	*7415*	Net Plant ($mill)	*7550*
4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	*8.5%*	*8.5%*	Return on Com Equity E	*9.0%*
1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	3.5%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
76%	62%	54%	57%	61%	50%	56%	57%	58%	59%	*63%*	*63%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	-2.1	+3.9	-2.5
Avg. Indust. Use (MWH)	16146	16041	16207
Avg. Indust. Revs. per KWH (¢)	4.99	4.94	4.79
Capacity at Peak (Mw)	4730	4743	4859
Peak Load, Summer (Mw)	3726	3976	3816
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.3	+1.1
Fixed Charge Cov. (%)	271	298	266

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-2.0%	-1.5%	*3.5%*
"Cash Flow"	2.5%	4.5%	*6.0%*
Earnings	3.5%	4.0%	*4.5%*
Dividends	4.5%	4.5%	*6.5%*
Book Value	2.5%	3.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	487	428	484	524	1923
2017	530	449	515	515	2009
2018	493	449	525	524	1991
2019	573	460	*547*	*545*	*2125*
2020	*550*	*475*	*560*	*565*	*2150*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.68	.42	.38	.68	2.16
2017	.82	.36	.44	.67	2.29
2018	.72	.51	.59	.55	2.37
2019	.82	.28	*.60*	*.70*	*2.40*
2020	*.85*	*.45*	*.52*	*.73*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.28	.28	.30	.30	1.16
2016	.30	.30	.32	.32	1.24
2017	.32	.32	.34	.34	1.32
2018	.34	.34	.3625	.3625	1.41
2019	.3625	.3625	.385	.385	

BUSINESS: Portland General Electric Company (PGE) provides electricity to 888,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 32%; industrial, 11%; other, 10%. Generating sources: gas, 28%; coal, 15%; wind, 8%; hydro, 8%; purchased, 41%. Fuel costs: 29% of revenues. '18 reported depreciation rate: 3.6%. Has 3,000 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

We have trimmed our 2019 earnings estimate for Portland General Electric by $0.05 a share, to $2.40. Second-quarter profits were much lower than usual due to higher expenses and lower tax credits. However, management did not adjust its earnings target of $2.35-$2.50 a share. In the electric utility industry, the timing of expenses can shift from one year to the next, and it appears this will be the case in the last six months of 2019. So, we raised our estimate for this period by $0.10 a share, partly offsetting the fact that June-quarter profits were $0.15 a share below our estimate. Note that the company's profits are benefiting from a modest rate increase that took effect at the start of the year.

We are sticking with our 2020 profit estimate of $2.55 a share. PGE should continue benefiting from moderate customer and load growth. The utility hasn't decided whether it will file a general rate case next year, but even if this happens, new tariffs almost certainly won't be in place in time to benefit earnings until 2021.

PGE has increased its capital budget. The company plans to spend $200 million to build an integrated operations center. Management expects the new facility to improve seismic resilience, cyber and physical security, and monitoring, control, and optimization of the utility's distribution system. The project is expected to be completed in 2021. Despite the higher capital spending plans, PGE expects it will not need to issue common equity through 2023.

Another significant project is under development. The utility will pay $160 million for a one-third stake in a 300-megawatt wind facility, which is scheduled for completion by yearend 2020. It's possible that PGE will build additional renewable-energy projects, depending on the outcome of a request for proposals that will follow a commission order on the integrated resource plan the utility filed in July.

This equity does not stand out among utilities for its dividend yield. This is a cut below the industry average. Total return potential isn't appealing, either for the 18-month or the 3- to 5-year period.

Paul E. Debbas, CFA *October 25, 2019*

(A) Diluted EPS. Excl. nonrecurring losses: '13, 42¢; '17, 19¢. Next earnings report due early November. (B) Div'ds paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '18: $4.49/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '19: 9.5%; earned on avg. com. eq., '18: 8.6%. Regulatory Climate: Average. (F) '05 per-share data are pro forma, based on shs. outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	85

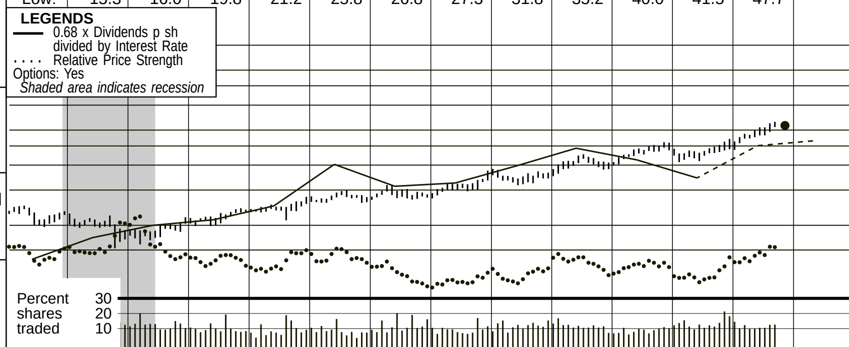
XCEL ENERGY NDQ-XEL

RECENT PRICE **63.15** | P/E RATIO **24.1** (Trailing: 25.8; Median: 15.0) | RELATIVE P/E RATIO **1.43** | DIV'D YLD **2.7%** | VALUE LINE

TIMELINESS **3** Lowered 9/20/19
SAFETY **1** Raised 5/1/15
TECHNICAL **2** Raised 10/25/19
BETA .50 (1.00 = Market)

High:	22.9	21.9	24.4	27.8	29.9	31.8	37.6	38.3	45.4	52.2	54.1	66.1
Low:	15.3	16.0	19.8	21.2	25.8	26.8	27.3	31.8	35.2	40.0	41.5	47.7

Target Price Range 2022 | 2023 | 2024



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$51-$69	$60 (-5%)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+5%)	4%
Low	50	(-20%)	-2%

Institutional Decisions

	4Q2018	1Q2019	2Q2019
to Buy	360	353	352
to Sell	294	308	308
Hld's(000)	392248	396450	404643

% TOT. RETURN 9/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	41.4	-5.2
3 yr.	73.0	24.7
5 yr.	151.3	40.8

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	*22.55*	*23.50*	Revenues per sh	*26.00*
3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	*6.20*	*6.60*	"Cash Flow" per sh	*8.00*
1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	*2.60*	*2.75*	Earnings per sh A	*3.25*
.75	.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	*1.62*	*1.72*	Div'd Decl'd per sh B ■	*2.05*
2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	*9.00*	*6.85*	Cap'l Spending per sh	*7.25*
12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	*25.25*	*26.40*	Book Value per sh C	*30.25*
398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	*525.00*	*526.00*	Common Shs Outst'g D	*530.00*
11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.66	.72	.82	.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	*Value Line*		Relative P/E Ratio	*.95*
5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 6/30/19
Total Debt $18146 mill. **Due in 5 Yrs** $4836 mill.
LT Debt $15996 mill. **LT Interest** $672 mill.
Incl. $145 mill. capitalized leases.
(LT interest earned: 2.6x)

Leases, Uncapitalized Annual rentals $239 mill.
Pension Assets-12/18 $2742 mill.
Oblig $3477 mill.

Pfd Stock None

Common Stock 515,010,683 shs.
as of 7/25/19
MARKET CAP: $33 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
9644.3	10311	10655	10128	10915	11686	11024	11107	11404	11537	*11850*	*12350*	Revenues ($mill)	*13800*
685.5	727.0	841.4	905.2	948.2	1021.3	1063.6	1123.4	1171.0	1261.0	*1350*	*1455*	Net Profit ($mill)	*1725*
35.1%	37.5%	35.8%	33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	12.6%	*8.0%*	*8.0%*	Income Tax Rate	*9.0%*
16.8%	11.7%	9.4%	10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*7.0%*
51.6%	53.1%	51.1%	53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	*56.0%*	*57.0%*	Long-Term Debt Ratio	*58.0%*
47.7%	46.3%	48.9%	46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	*44.0%*	*43.0%*	Common Equity Ratio	*42.0%*
15277	17452	17331	19018	20477	21714	23092	25216	25975	28025	*30300*	*32125*	Total Capital ($mill)	*36900*
18508	20663	22353	23809	26122	28757	31206	32842	34329	36944	*39750*	*41325*	Net Plant ($mill)	*45400*
6.2%	5.7%	6.5%	6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.3%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	*10.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.4%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	*10.0%*	*10.5%*	Return on Com Equity E	*11.0%*
3.7%	3.6%	4.3%	4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
61%	59%	56%	54%	54%	55%	57%	61%	62%	58%	*62%*	*62%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2016	2017	2018
% Change Retail Sales (KWH)	+.3	-.7	+3.2
Large C & I Use (MWH)	22519	22642	23004
Large C & I Revs. per KWH (¢)	6.17	6.36	5.91
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	20423	19591	20293
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.9	+1.1
Fixed Charge Cov. (%)	342	330	281

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-1.0%	.5%	*2.5%*
"Cash Flow"	4.5%	6.5%	*6.5%*
Earnings	5.5%	5.0%	*5.5%*
Dividends	4.5%	6.0%	*6.0%*
Book Value	4.5%	4.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	2772	2500	3040	2795	11107
2017	2946	2645	3017	2796	11404
2018	2951	2658	3048	2880	11537
2019	3141	2577	*3150*	*2982*	*11850*
2020	*3250*	*2750*	*3250*	*3100*	*12350*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.47	.39	.90	.45	2.21
2017	.47	.45	.97	.42	2.30
2018	.57	.52	.96	.42	2.47
2019	.61	.46	*1.05*	*.48*	*2.60*
2020	*.63*	*.52*	*1.10*	*.50*	*2.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.30	.32	.32	.32	1.26
2016	.32	.34	.34	.34	1.34
2017	.34	.36	.36	.36	1.42
2018	.36	.38	.38	.38	1.50
2019	.38	.405	.405	.405	

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.6 mill. electric, 2.0 mill. gas. Elec. rev. breakdown: residential, 31%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 41% of revs. '18 reported depr. rate: 3.1%. Has 11,100 employees. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy's utility in Colorado has a tough rate case pending. Public Service of Colorado requested an electric increase of $158.3 million, based on a return of 10.35% on a common-equity ratio of 56.46%. However, the staff of the Colorado commission is recommending a hike of just $7.7 million, based on a return of 9% on a common-equity ratio of 55.57%, and intervenors' proposals are even lower. PSCo has a track record of reaching settlements, but this does not mean that this will occur in this case. An order is due in time for new tariffs to take effect at the start of 2020.

Southwestern Public Service has electric applications pending in Texas and New Mexico. The utility wants to place wind projects in the rate base. In Texas, SPS is seeking $136.5 million, based on a return of 10.35% on a common-equity ratio of 54.65%. New rates are expected to go into effect in the second quarter. In New Mexico, the utility filed for a net hike of $26 million, based on a return of 10.35% on a common-equity ratio of 54.77%. New rates are expected to take effect in the second or third period.

Rate relief is the primary reason for the company's steady profit growth in recent years. Xcel's goal for annual profit growth is 5%-7%, and our 2019 and 2020 share-earnings estimates would produce increases within this range. Our 2019 estimate is at the midpoint of the company's targeted range of $2.55-$2.65, and management has stated its expectation of being at the midpoint to the upper end of this range.

The Minnesota commission rejected a proposed asset acquisition by Northern States Power. The utility agreed to pay $650 million for a 760-megawatt gas-fired plant (from which it is already buying power). The regulators opposed ownership as a utility asset, so Xcel intends to purchase the facility under the same terms, but as a nonregulated asset. Xcel expects this will provide the same return on investment as a utility plant.

This top-quality stock has a high valuation. The dividend yield is somewhat below the utility average. Total return potential isn't appealing, either for the 18-month span or the 2022-2024 period.

Paul E. Debbas, CFA *October 25, 2019*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (losses) on discontinued ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '17 EPS don't sum due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '18: $5.92/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on com. eq. (blended): 9.6%; earned on avg. com. eq., '18: 10.4%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	100

Jersey Central Power & Light Company
Summary of Risk Premium Models for the Proxy Group of Seventeen Electric Companies

	Proxy Group of Seventeen Electric Companies
Predictive Risk Premium Model (PRPM) (1)	9.94 %
Risk Premium Using an Adjusted Total Market Approach (2)	9.38 %
Average	9.66 %

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.

Jersey Central Power & Light Company
Indicated ROE
Derived by the Predictive Risk Premium Model (1)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Seventeen Electric Companies	LT Average Predicted Variance	Spot Predicted Variance	Recommended Variance (2)	GARCH Coefficient	Predicted Risk Premium (3)	Risk-Free Rate (4)	Indicated ROE (5)
ALLETE, Inc.	0.28%	0.21%	0.28%	2.2841	7.94%	2.70%	10.64%
Alliant Energy Corporation	0.26%	0.15%	0.21%	2.7386	7.04%	2.70%	9.74%
American Electric Power Co., Inc.	0.28%	0.17%	0.22%	2.4752	6.81%	2.70%	9.51%
Avista Corporation	0.47%	0.26%	0.36%	1.0297	4.60%	2.70%	7.30%
Duke Energy Corporation	0.31%	0.23%	0.27%	1.8052	5.99%	2.70%	8.69%
Edison International	0.43%	0.77%	0.60%	1.5434	11.64%	2.70%	14.34%
Entergy Corporation	0.39%	0.22%	0.30%	2.3244	8.79%	2.70%	11.49%
Eversource Energy	0.31%	0.19%	0.25%	1.7038	5.18%	2.70%	7.88%
FirstEnergy Corp.	0.29%	0.15%	0.22%	2.0165	5.48%	2.70%	8.18%
IDACORP, Inc.	0.28%	0.20%	0.24%	2.2715	6.76%	2.70%	9.46%
NorthWestern Corporation	0.32%	0.20%	0.26%	3.0456	9.82%	2.70%	12.52%
OGE Energy Corporation	0.30%	0.21%	0.26%	2.3394	7.45%	2.70%	10.15%
Otter Tail Corporation	0.37%	0.68%	0.53%	1.7119	11.34%	2.70%	14.04%
Pinnacle West Capital Corp.	0.59%	0.30%	0.45%	1.2683	7.00%	2.70%	9.70%
PNM Resources, Inc.	0.52%	0.33%	0.43%	1.3714	7.27%	2.70%	9.97%
Portland General Electric Co.	0.24%	0.11%	0.17%	2.6098	5.59%	2.70%	8.29%
Xcel Energy, Inc.	0.27%	0.17%	0.22%	2.8204	7.83%	2.70%	10.53%
						Average	10.14%
						Median	9.74%
						Average of Mean and Median	9.94%

NMF = Not Meaningful Figure

Notes:
(1) The Predictive Risk Premium Model uses historical data to generate a predicted variance and a GARCH coefficient. The historical data used are the equity risk premiums for the first available trading month as reported by Bloomberg Professional Service.
(2) Average of Columns [1] and [2].
(3) (1+(Column [3] * Column [4])^12) - 1.
(4) From note 2 on page 2 of Schedule DWD-4.
(5) Column [5] + Column [6].

Jersey Central Power & Light Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Seventeen Electric Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	3.68 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A Rated Public Utility Bonds	0.37 (2)
3.	Adjusted Prospective Yield on A Rated Public Utility Bonds	4.05 %
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group	0.17 (3)
5.	Adjusted Prospective Bond Yield	4.22 %
6.	Equity Risk Premium (4)	5.16
7.	Risk Premium Derived Common Equity Cost Rate	9.38 %

Notes:
(1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 10-11 of this Schedule).
(2) The average yield spread of A rated public utility bonds over Aaa rated corporate bonds of 0.37% from page 4 of this Schedule.
(3) Adjustment to reflect the A3/Baa1 Moody's LT issuer rating of the Utility Proxy Group as shown on page 5 of this Schedule. The 0.17% upward adjustment is derived by taking 1/2 of the spread between A2 and Baa2 Public Utility Bonds (1/2 * 0.34% = 0.17%) as derived from page 4 of this Schedule.
(4) From page 7 of this Schedule.

Jersey Central Power & Light Company
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1]	[2]	[3]
	Aaa Rated Corporate Bond	A Rated Public Utility Bond	Baa Rated Public Utility Bond
Dec-2019	3.01 %	3.40 %	3.73 %
Nov-2019	3.06	3.42	3.76
Oct-2019	3.01	3.39	3.72
Average	3.03 %	3.40 %	3.74 %

Selected Bond Spreads

A Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:
0.37 % (1)

Baa Rated Public Utility Bonds Over A Rated Public Utility Bonds:
0.34 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Service

Jersey Central Power & Light Company
Comparison of Long-Term Issuer Ratings for
Proxy Group of Seventeen Electric Companies

	Moody's Long-Term Issuer Rating December 2019		Standard & Poor's Long-Term Issuer Rating December 2019	
Proxy Group of Seventeen Electric Companies	Long-Term Issuer Rating (1)	Numerical Weighting (2)	Long-Term Issuer Rating (1)	Numerical Weighting (2)
ALLETE, Inc.	A3	7.0	NR	- -
Alliant Energy Corporation	A3/Baa1	7.5	A-/A	6.5
American Electric Power Co., Inc.	Baa1	8.0	A-	7.0
Avista Corporation	Baa3	10.0	NR	- -
Duke Energy Corporation	A3	7.0	A-	7.0
Edison International	Baa2	9.0	BBB	9.0
Entergy Corporation	Baa1	8.0	A-	7.0
Eversource Energy	A3	7.0	A-/A	6.5
FirstEnergy Corp.	Baa1	8.0	BBB	9.0
IDACORP, Inc.	A3	7.0	BBB	9.0
NorthWestern Corporation	NR	- -	NR	- -
OGE Energy Corporation	A3	7.0	A-	7.0
Otter Tail Corporation	A3	7.0	BBB+	8.0
Pinnacle West Capital Corp.	A2	6.0	A-	7.0
PNM Resources, Inc.	Baa1	8.0	A-/BBB+	7.5
Portland General Electric Co.	A3	7.0	BBB+	8.0
Xcel Energy, Inc.	A3	7.0	A-	7.0
Average	A3 / Baa1	7.5	A- / BBB+	7.5

Notes:

(1) Ratings are that of the average of each company's utility operating subsidiaries.
(2) From page 6 of this Schedule.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Jersey Central Power & Light Company
Judgment of Equity Risk Premium for
Proxy Group of Seventeen Electric Companies

Line No.		Proxy Group of Seventeen Electric Companies
1.	Calculated equity risk premium based on the total market using the beta approach (1)	4.77 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A rated bonds (2)	5.03
3.	Predicted Equity Risk Premium Based on Regression Analysis of 1158 Fully-Litigated Electric Utility Rate Cases	5.68
4.	Average equity risk premium	5.16 %

Notes: (1) From page 8 of this Schedule.
(2) From page 12 of this Schedule.
(3) From page 13 of this Schedule.

Jersey Central Power & Light Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Seventeen Electric Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Seventeen Electric Companies
	Ibbotson-Based Equity Risk Premiums:	
1.	Ibbotson Equity Risk Premium (1)	5.54 %
2.	Regression on Ibbotson Risk Premium Data (2)	8.61
3.	Ibbotson Equity Risk Premium based on PRPM (3)	7.38
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	8.80
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	10.89
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	9.91
7.	Conclusion of Equity Risk Premium	8.52 %
8.	Adjusted Beta (7)	0.56
9.	Forecasted Equity Risk Premium	4.77 %

Notes provided on page 9 of this Schedule.

Jersey Central Power & Light Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Seventeen Electric Companies

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Ibbotson® SBBI® 2019 Market Report minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1926-2018.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa rated corporate bond yields from 1928-2018 referenced in Note 1 above.

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through December 2019.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 3.68% (from page 3 of this Schedule) from the projected 3-5 year total annual market return of 12.48% (described fully in note 1 on page 2 of Schedule DWD-4).

(5) Using data from Value Line for the S&P 500, an expected total return of 14.57% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 3.68% results in an expected equity risk premium of 10.89%.

(6) Using data from the Bloomberg Professional Service for the S&P 500, an expected total return of 13.59% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 3.68% results in an expected equity risk premium of 9.91%.

(7) Average of mean and median beta from page 1 of Schedule DWD-4.

Sources of Information:

Stocks, Bonds, Bills, and Inflation - 2019 SBBI Yearbook, John Wiley & Sons, Inc.
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, January 1, 2020 and December 1, 2019
Bloomberg Professional Service

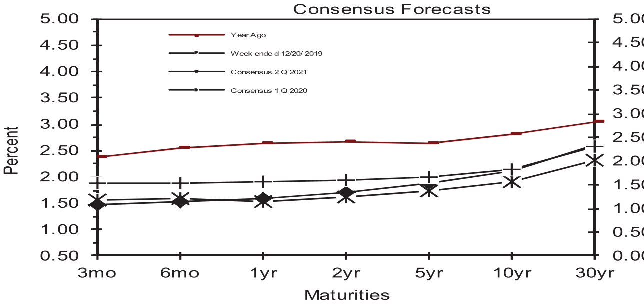
Exhibit JC-10
Schedule DWD-3
Page 10 of 13

Consensus Forecasts of U.S. Interest Rates and Key Assumptions

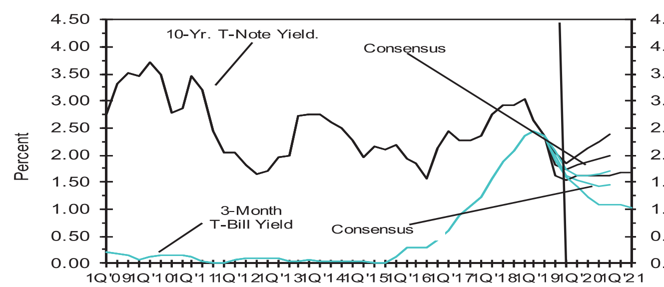
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	1Q	2Q	3Q	4Q	1Q	2Q
Interest Rates	Dec 20	Dec 13	Dec 6	Nov 29	Nov	Oct	Sep	4Q 2019*	**2020**	**2020**	**2020**	**2020**	**2021**	**2021**
Federal Funds Rate	1.55	1.55	1.56	1.55	1.55	1.83	2.04	1.66	**1.6**	**1.5**	**1.5**	**1.4**	**1.5**	**1.5**
Prime Rate	4.75	4.75	4.75	4.75	4.75	4.99	5.15	4.84	**4.7**	**4.7**	**4.6**	**4.6**	**4.6**	**4.6**
LIBOR, 3-mo.	1.91	1.89	1.89	1.91	1.90	1.98	2.13	1.93	**1.9**	**1.8**	**1.7**	**1.8**	**1.7**	**1.8**
Commercial Paper, 1-mo.	1.64	1.61	1.63	1.58	1.62	1.86	2.01	1.72	**1.7**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**
Treasury bill, 3-mo.	1.57	1.56	1.56	1.61	1.57	1.68	1.93	1.61	**1.5**	**1.5**	**1.4**	**1.4**	**1.5**	**1.5**
Treasury bill, 6-mo.	1.58	1.57	1.57	1.62	1.59	1.67	1.89	1.61	**1.6**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**
Treasury bill, 1 yr.	1.53	1.55	1.57	1.59	1.57	1.61	1.80	1.58	**1.6**	**1.6**	**1.5**	**1.6**	**1.6**	**1.6**
Treasury note, 2 yr.	1.63	1.63	1.58	1.61	1.61	1.55	1.65	1.59	**1.6**	**1.6**	**1.6**	**1.6**	**1.7**	**1.7**
Treasury note, 5 yr.	1.73	1.68	1.62	1.61	1.64	1.53	1.57	1.61	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.9**
Treasury note, 10 yr.	1.91	1.84	1.79	1.76	1.81	1.71	1.70	1.78	**1.8**	**1.9**	**1.9**	**2.0**	**2.1**	**2.1**
Treasury note, 30 yr.	2.33	2.27	2.24	2.20	2.28	2.19	2.16	2.25	**2.3**	**2.4**	**2.4**	**2.5**	**2.5**	**2.6**
Corporate Aaa bond	3.13	3.11	3.12	3.07	3.16	3.11	3.10	3.13	**3.2**	**3.3**	**3.4**	**3.5**	**3.5**	**3.6**
Corporate Baa bond	3.78	3.77	3.81	3.77	3.86	3.86	3.84	3.84	**4.1**	**4.2**	**4.3**	**4.4**	**4.5**	**4.5**
State & Local bonds	3.10	3.10	3.12	3.10	3.15	3.14	3.15	3.13	**2.9**	**3.0**	**3.1**	**3.1**	**3.2**	**3.2**
Home mortgage rate	3.73	3.73	3.68	3.68	3.70	3.69	3.61	3.70	**3.7**	**3.8**	**3.8**	**3.9**	**4.0**	**4.0**
	History								Consensus Forecasts-Quarterly					
	1Q	2Q	3Q	4Q	1Q	2Q	*3Q*	*4Q*	1Q	2Q	3Q	4Q	1Q	2Q
Key Assumptions	2018	2018	2018	2018	2019	2019	*2019*	*2019***	**2020**	**2020**	**2020**	**2020**	**2021**	**2021**
Fed's AFE $ Index	102.9	105.5	107.8	109.4	109.4	110.3	110.5	110.4	**109.6**	**109.1**	**108.8**	**108.4**	**108.3**	**108.1**
Real GDP	2.5	3.5	2.9	1.1	3.1	2.0	2.1	1.8	**1.6**	**1.8**	**1.8**	**1.9**	**1.9**	**2.0**
GDP Price Index	2.3	3.2	2.0	1.6	1.1	2.4	1.8	1.8	**1.9**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
Consumer Price Index	3.2	2.1	2.0	1.5	0.9	2.9	1.8	2.3	**2.1**	**2.0**	**2.1**	**2.0**	**2.1**	**2.0**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS). **Interest rate data for 4Q 2019 are based on historical data through the week ended December 20.* ***Data for 4Q 2019 for the Fed's AFE $ Index based on data through week ended December 20. Figures for 4Q 2019 Real GDP, GDP Chained Price Index and Consumer Price Index are consensus forecasts based on a special question asked of the panelists this month.*

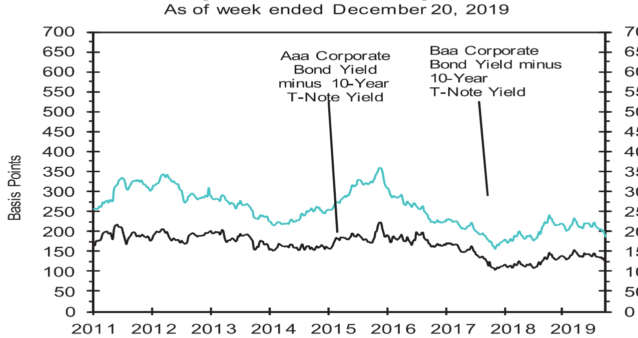
U.S. Treasury Yield Curve
Week ended December 20, 2019 & Year Ago vs. 1Q 2020 & 2Q 2021 Consensus Forecasts



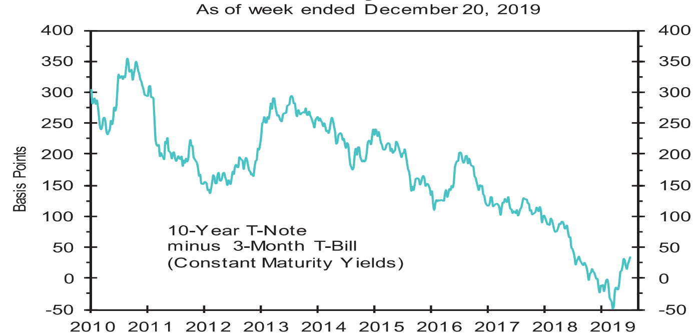
U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield
(Quarterly Average) Forecast



Corporate Bond Spreads
As of week ended December 20, 2019



U.S. Treasury Yield Curve
As of week ended December 20, 2019



Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2021 through 2025 and averages for the five-year periods 2021-2025 and 2026-2030. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
		2021	2022	2023	2024	2025	2021-2025	2026-2030
1. Federal Funds Rate	**CONSENSUS**	**1.5**	**1.9**	**2.1**	**2.3**	**2.4**	**2.1**	**2.4**
	Top 10 Average	2.1	2.6	2.7	2.9	3.0	2.6	3.0
	Bottom 10 Average	1.0	1.2	1.5	1.8	1.9	1.5	1.9
2. Prime Rate	**CONSENSUS**	**4.5**	**4.9**	**5.1**	**5.4**	**5.5**	**5.1**	**5.5**
	Top 10 Average	5.0	5.5	5.7	6.0	6.0	5.6	6.0
	Bottom 10 Average	4.0	4.3	4.6	4.9	5.0	4.5	5.0
3. LIBOR, 3-Mo.	**CONSENSUS**	**1.9**	**2.2**	**2.4**	**2.6**	**2.7**	**2.3**	**2.7**
	Top 10 Average	2.4	2.7	2.9	3.1	3.2	2.9	3.2
	Bottom 10 Average	1.4	1.6	1.8	2.0	2.2	1.8	2.2
4. Commercial Paper, 1-Mo.	**CONSENSUS**	**1.7**	**2.1**	**2.3**	**2.5**	**2.7**	**2.3**	**2.7**
	Top 10 Average	2.2	2.5	2.8	3.0	3.1	2.7	3.1
	Bottom 10 Average	1.3	1.6	1.8	2.1	2.2	1.8	2.2
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	**1.5**	**1.8**	**2.0**	**2.3**	**2.4**	**2.0**	**2.4**
	Top 10 Average	2.1	2.6	2.7	2.9	3.0	2.6	**3.0**
	Bottom 10 Average	1.0	1.2	1.4	1.7	1.8	1.4	**1.8**
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	**1.6**	**1.9**	**2.2**	**2.4**	**2.5**	**2.1**	**2.5**
	Top 10 Average	2.2	2.6	2.8	3.0	3.1	2.7	**3.1**
	Bottom 10 Average	1.1	1.3	1.5	1.8	2.0	1.5	**2.0**
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	**1.7**	**2.0**	**2.2**	**2.5**	**2.6**	**2.2**	**2.7**
	Top 10 Average	2.3	2.7	2.9	3.2	3.2	2.8	**3.2**
	Bottom 10 Average	1.2	1.3	1.6	1.9	2.1	1.6	**2.1**
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	**1.8**	**2.1**	**2.4**	**2.6**	**2.7**	**2.3**	**2.8**
	Top 10 Average	2.4	2.8	3.1	3.3	3.4	3.0	**3.4**
	Bottom 10 Average	1.2	1.5	1.7	2.0	2.2	1.7	**2.2**
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	**2.0**	**2.3**	**2.6**	**2.8**	**2.9**	**2.5**	**3.0**
	Top 10 Average	2.6	3.0	3.2	3.5	3.5	3.2	**3.6**
	Bottom 10 Average	1.5	1.7	1.9	2.1	2.3	1.9	**2.3**
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	**2.3**	**2.5**	**2.8**	**3.0**	**3.1**	**2.8**	**3.2**
	Top 10 Average	2.9	3.3	3.6	3.8	3.9	3.5	**4.0**
	Bottom 10 Average	1.8	1.9	2.1	2.3	2.4	2.1	**2.5**
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	**2.8**	**3.0**	**3.2**	**3.5**	**3.6**	**3.2**	**3.7**
	Top 10 Average	3.3	3.6	4.0	4.2	4.3	3.9	**4.4**
	Bottom 10 Average	2.2	2.4	2.5	2.7	2.9	2.6	**2.9**
13. Corporate Aaa Bond Yield	**CONSENSUS**	**3.7**	**4.0**	**4.3**	**4.5**	**4.6**	**4.2**	**4.7**
	Top 10 Average	4.3	4.6	4.9	5.2	5.3	4.9	**5.4**
	Bottom 10 Average	3.2	3.4	3.6	3.7	3.9	3.6	**4.0**
13. Corporate Baa Bond Yield	**CONSENSUS**	**4.7**	**4.9**	**5.2**	**5.4**	**5.6**	**5.2**	**5.6**
	Top 10 Average	5.3	5.6	5.9	6.2	6.3	5.9	**6.4**
	Bottom 10 Average	4.2	4.3	4.4	4.6	4.8	4.5	**4.8**
14. State & Local Bonds Yield	**CONSENSUS**	**3.6**	**3.7**	**3.9**	**4.1**	**4.2**	**3.9**	**4.2**
	Top 10 Average	4.0	4.3	4.5	4.6	4.7	4.4	**4.7**
	Bottom 10 Average	3.2	3.2	3.3	3.5	3.7	3.4	**3.8**
15. Home Mortgage Rate	**CONSENSUS**	**4.1**	**4.2**	**4.5**	**4.7**	**4.8**	**4.5**	**4.9**
	Top 10 Average	4.5	4.8	5.1	5.4	5.4	5.0	**5.5**
	Bottom 10 Average	3.7	3.7	3.9	4.1	4.2	3.9	**4.2**
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**108.8**	**108.8**	**109.1**	**109.2**	**108.8**	**108.9**	**108.3**
	Top 10 Average	110.6	110.7	111.1	111.5	111.6	111.1	111.8
	Bottom 10 Average	107.0	107.0	107.1	107.1	106.5	106.9	105.7

		Year-Over-Year, % Change					Five-Year Averages	
		2021	2022	2023	2024	2025	2021-2025	2026-2030
B. Real GDP	**CONSENSUS**	**1.9**	**2.0**	**2.0**	**1.9**	**2.0**	**1.9**	**2.0**
	Top 10 Average	2.4	2.4	2.3	2.2	2.2	2.3	2.3
	Bottom 10 Average	1.4	1.6	1.6	1.7	1.7	1.6	1.7
C. GDP Chained Price Index	**CONSENSUS**	**2.2**	**2.3**	**2.3**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.6	2.8	2.7	2.6	2.6	2.7	2.6
	Bottom 10 Average	1.8	1.8	1.9	1.9	1.9	1.9	1.9
D. Consumer Price Index	**CONSENSUS**	**2.1**	**2.2**	**2.2**	**2.2**	**2.1**	**2.2**	**2.1**
	Top 10 Average	2.4	2.4	2.5	2.4	2.3	2.4	2.3
	Bottom 10 Average	1.8	1.9	2.0	2.0	1.9	1.9	2.0

Jersey Central Power & Light Company
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium
	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1):	
1.	Historical Equity Risk Premium	4.00 %
2.	Regression of Historical Equity Risk Premium (2)	6.22
3.	Forecasted Equity Risk Premium Based on PRPM (3)	3.85
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	6.24
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	4.85
6.	Average Equity Risk Premium (6)	5.03 %

Notes:

(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2018. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A rated public utility bond yields from 1928 - 2018 referenced in note 1 above.

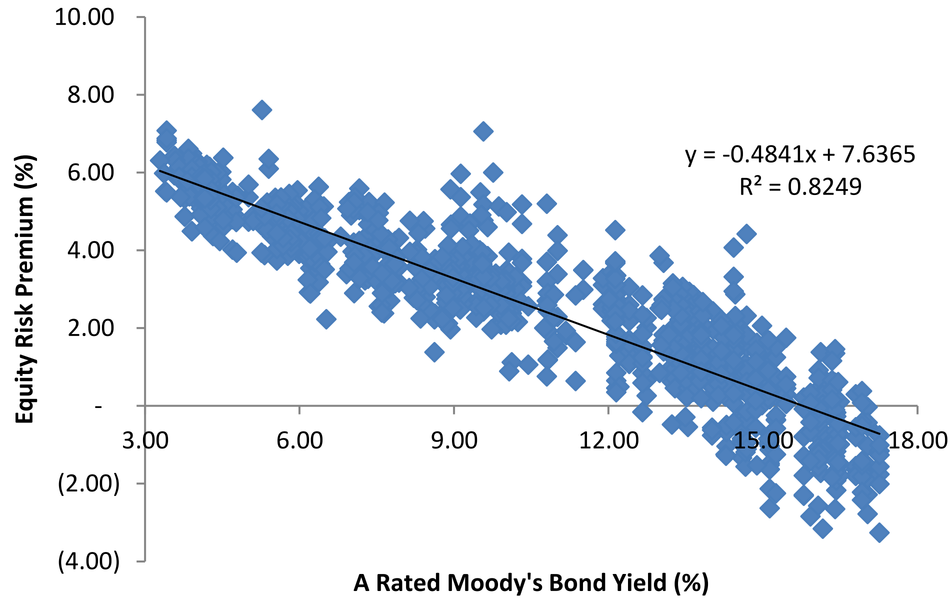
(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A rated public utility bonds from January 1928 - December 2019.

(4) Using data from Value Line for the S&P Utilities Index, an expected return of 10.29% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A rated public utility bond yield of 4.05%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 6.24%. (10.29% - 4.05% = 6.24%)

(5) Using data from Bloomberg Professional Service for the S&P Utilities Index, an expected return of 8.90% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A rated public utility bond yield of 4.05%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 4.85%. (8.90% - 4.05% = 4.85%)

(6) Average of lines 1 through 5.

Jersey Central Power & Light Company
Prediction of Equity Risk Premiums Relative to
Moody's A Rated Utility Bond Yields



Constant	Slope	Prospective A Rated Utility Bond (1)	Prospective Equity Risk Premium
7.636492 %	-0.48406	4.05 %	5.68 %

Notes:
(1) From line 3 of page 3 of this Schedule.

Source of Information: Regulatory Research Associates

Jersey Central Power & Light Company
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Seventeen Electric Companies	[1] Value Line Adjusted Beta	[2] Bloomberg Adjusted Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (2)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost Rate (3)
ALLETE, Inc.	0.65	0.49	0.57	9.54 %	2.70 %	8.14 %	9.16 %	8.65 %
Alliant Energy Corporation	0.60	0.54	0.57	9.54	2.70	8.14	9.16	8.65
American Electric Power Co., Inc.	0.55	0.53	0.54	9.54	2.70	7.85	8.95	8.40
Avista Corporation	0.60	0.48	0.54	9.54	2.70	7.85	8.95	8.40
Duke Energy Corporation	0.50	0.45	0.48	9.54	2.70	7.28	8.52	7.90
Edison International	0.60	0.58	0.59	9.54	2.70	8.33	9.31	8.82
Entergy Corporation	0.60	0.49	0.55	9.54	2.70	7.95	9.02	8.48
Eversource Energy	0.55	0.59	0.57	9.54	2.70	8.14	9.16	8.65
FirstEnergy Corp.	0.65	0.60	0.63	9.54	2.70	8.71	9.59	9.15
IDACORP, Inc.	0.55	0.48	0.51	9.54	2.70	7.57	8.73	8.15
NorthWestern Corporation	0.60	0.52	0.56	9.54	2.70	8.04	9.09	8.57
OGE Energy Corporation	0.75	0.58	0.66	9.54	2.70	9.00	9.81	9.40
Otter Tail Corporation	0.70	0.60	0.65	9.54	2.70	8.90	9.74	9.32
Pinnacle West Capital Corp.	0.55	0.44	0.50	9.54	2.70	7.47	8.66	8.07
PNM Resources, Inc.	0.60	0.54	0.57	9.54	2.70	8.14	9.16	8.65
Portland General Electric Co.	0.60	0.51	0.56	9.54	2.70	8.04	9.09	8.57
Xcel Energy, Inc.	0.50	0.52	0.51	9.54	2.70	7.57	8.73	8.15
Mean			0.56			8.07 %	9.11 %	8.59 %
Median			0.56			8.04 %	9.09 %	8.57 %
Average of Mean and Median			0.56			8.06	9.10	8.58 %

Notes on page 2 of this Schedule.

Jersey Central Power & Light Company
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using six different measures from three sources: Ibbotson, Value Line, and Bloomberg as illustrated below:

Historical Data MRP Estimates:

Measure 1: Ibbotson Arithmetic Mean MRP (1926-2018)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2018:	11.89 %
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.12
MRP based on Ibbotson Historical Data:	6.77 %

Measure 2: Application of a Regression Analysis to Ibbotson Historical Data (1926-2018) — 9.63 %

Measure 3: Application of the PRPM to Ibbotson Historical Data: (January 1926 - December 2019) — 8.31 %

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP (Thirteen weeks ending January 03, 2020)

Total projected return on the market 3-5 years hence*:	12.48 %
Projected Risk-Free Rate (see note 2):	2.70
MRP based on Value Line Summary & Index:	9.78 %

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Value Line Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	14.57 %
Projected Risk-Free Rate (see note 2):	2.70
MRP based on Value Line data	11.87 %

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	13.59 %
Projected Risk-Free Rate (see note 2):	2.70
MRP based on Bloomberg data	10.89 %
Average of Value Line, Ibbotson, and Bloomberg MRP:	9.54 %

(2) For reasons explained in the direct testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 10-11 of Schedule DWD-3.) The projection of the risk-free rate is illustrated below:

First Quarter 2020	2.30 %
Second Quarter 2020	2.40
Third Quarter 2020	2.40
Fourth Quarter 2020	2.50
First Quarter 2021	2.50
Second Quarter 2021	2.60
2021-2025	3.20
2026-2030	3.70
	2.70 %

(3) Average of Column 6 and Column 7.

Sources of Information:

Value Line Summary and Index
Blue Chip Financial Forecasts, January 1, 2020 and December 1, 2019
Stocks, Bonds, Bills, and Inflation - 2019 SBBI Yearbook, John Wiley & Sons, Inc.
Bloomberg Professional Services

Jersey Central Power & Light Company
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Utility Proxy Group

The criteria for selection of the Non-Price Regulated Proxy Group was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The Non-Price Regulated Proxy Group was then selected based on the unadjusted beta range of 0.18 – 0.54 and residual standard error of the regression range of 2.1173– 2.5253 of the Utility Proxy Group.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1020. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus, } 0.1020 = \frac{2.3213}{\sqrt{518}} = \frac{2.3213}{22.7596}$$

Source of Information: Value Line, Inc., December 2019
Value Line Investment Survey (Standard Edition)

Jersey Central Power & Light Company
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Seventeen Electric Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
ALLETE, Inc.	0.65	0.45	2.2959	0.0874
Alliant Energy Corporation	0.60	0.37	2.2031	0.0839
American Electric Power Co., Inc.	0.55	0.27	2.1673	0.0825
Avista Corporation	0.65	0.41	2.4420	0.0930
Duke Energy Corporation	0.50	0.19	2.1062	0.0802
Edison International	0.55	0.30	2.3875	0.0909
Entergy Corporation	0.60	0.32	2.3251	0.0885
Eversource Energy	0.60	0.32	2.1774	0.0829
FirstEnergy Corp.	0.60	0.37	2.6376	0.1004
IDACORP, Inc.	0.55	0.31	2.2870	0.0871
NorthWestern Corporation	0.55	0.31	2.3218	0.0884
OGE Energy Corporation	0.85	0.76	2.2336	0.0850
Otter Tail Corporation	0.75	0.59	2.5315	0.0964
Pinnacle West Capital Corp.	0.55	0.29	2.2075	0.0840
PNM Resources, Inc.	0.65	0.39	2.7268	0.1038
Portland General Electric Co.	0.60	0.32	2.3287	0.0887
Xcel Energy, Inc.	0.50	0.21	2.0836	0.0793
Average	0.61	0.36	2.3213	0.0884

Beta Range (+/- 2 std. Devs. of Beta)	0.18	0.54
2 std. Devs. of Beta	0.18	
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.1173	2.5253
Std. dev. of the Res. Std. Err.	0.1020	
2 std. devs. of the Res. Std. Err.	0.2040	

Source of Information: Valueline Proprietary Database, December 2019

Jersey Central Power & Light Company
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seventeen Electric Companies

	[1]	[2]	[3]	[4]
Proxy Group of Six Non-Price Regulated Companies	VL Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Advanced Disposal	0.70	0.50	2.4839	0.2082
Compass Diversified	0.70	0.50	2.1397	0.0815
Kellogg	0.70	0.49	2.1387	0.0814
Altria Group	0.65	0.47	2.2885	0.0871
Smucker (J.M.) Co.	0.70	0.52	2.4415	0.0930
Walmart Inc.	0.70	0.51	2.1899	0.0834
Average	0.69	0.50	2.2800	0.1100
Proxy Group of Seventeen Electric Companies	0.61	0.36	2.3213	0.0884

Source of Information: Valueline Proprietary Database, December 2019

Jersey Central Power & Light Company
Summary of Cost of Equity Models Applied to
Proxy Group of Six Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seventeen Electric Companies

Principal Methods	Proxy Group of Six Non-Price Regulated Companies
Discounted Cash Flow Model (DCF) (1)	9.38 %
Risk Premium Model (RPM) (2)	10.82
Capital Asset Pricing Model (CAPM) (3)	9.99
Mean	10.06 %
Median	9.99 %
Average of Mean and Median	10.03 %

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.
(3) From page 6 of this Schedule.

Jersey Central Power & Light Company
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seventeen Electric Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Six Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
Advanced Disposal	- %	NA %	10.00 %	19.72 %	14.86 %	- %	NA %
Compass Diversified	6.47	NA	NA	7.00	7.00	6.70	13.70
Kellogg	3.53	4.00	6.00	(0.80)	5.00	3.62	8.62
Altria Group	7.06	8.50	6.40	6.17	7.02	7.31	14.33
Smucker (J.M.) Co.	3.33	5.00	2.50	1.15	2.88	3.38	6.26
Walmart Inc.	1.78	7.50	5.00	5.18	5.89	1.83	7.72
						Mean	10.13 %
						Median	8.62 %
						Average of Mean and Median	9.38 %

NA= Not Available
NMF= Not Meaningful Figure

(1) The application of the DCF model to the domestic, non-price regluated comparable risk companies is identical to the application of the DCF to the Utility Proxy Group. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of December 31, 2019. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

Source of Information: Value Line Investment Survey
www.zacks.com Downloaded on 12/31/2019
www.yahoo.com Downloaded on 12/31/2019

Jersey Central Power & Light Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Six Non-Price Regulated Companies
1.	Prospective Yield on Baa Rated Corporate Bonds (1)	4.60 %
2.	Equity Risk Premium (2)	6.22
3.	Risk Premium Derived Common Equity Cost Rate	10.82 %

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated January 1, 2020 and December 1, 2019 (see pages 10-11 of Schedule DWD-3). The estimates are detailed below.

First Quarter 2020	4.10 %
Second Quarter 2020	4.20
Third Quarter 2020	4.30
Fourth Quarter 2020	4.40
First Quarter 2021	4.50
Second Quarter 2021	4.50
2021-2025	5.20
2026-2030	5.60
Average	4.60 %

(2) From page 5 of this Schedule.

Jersey Central Power & Light Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Six Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Seventeen Electric Companies

Proxy Group of Six Non-Price Regulated Companies	Moody's Long-Term Issuer Rating December 2019: Long-Term Issuer Rating	Moody's: Numerical Weighting (1)	Standard & Poor's Long-Term Issuer Rating December 2019: Long-Term Issuer Rating	Standard & Poor's: Numerical Weighting (1)
Advanced Disposal	B3	16.0	BB-	13.0
Compass Diversified	NR	--	NR	--
Kellogg	Baa2	9.0	BBB	9.0
Altria Group	A3	7.0	BBB	9.0
Smucker (J.M.) Co.	Baa2	9.0	BBB	9.0
Walmart Inc.	Aa2	3.0	AA	3.0
Average	Baa2	8.8	BBB	8.6

Notes:
(1) From page 6 of Schedule DWD-3.

Source of Information:
Bloomberg Professional Services

Jersey Central Power & Light Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Proxy Group of Six Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Seventeen Electric Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Six Non-Price Regulated Companies
	Ibbotson-Based Equity Risk Premiums:	
1.	Ibbotson Equity Risk Premium (1)	5.54 %
2.	Regression on Ibbotson Risk Premium Data (2)	8.61
3.	Ibbotson Equity Risk Premium based on PRPM (3)	7.38
5.	Equity Risk Premium Based on Value Line Summary and Index (4)	8.80
6.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	10.89
8.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	9.91
9.	Conclusion of Equity Risk Premium	8.52 %
10.	Adjusted Beta (7)	0.73
11.	Forecasted Equity Risk Premium	6.22 %

Notes:
(1) From note 1 of page 9 of Schedule DWD-3.
(2) From note 2 of page 9 of Schedule DWD-3.
(3) From note 3 of page 9 of Schedule DWD-3.
(4) From note 4 of page 9 of Schedule DWD-3.
(5) From note 5 of page 9 of Schedule DWD-3.
(6) From note 6 of page 9 of Schedule DWD-3.
(7) Average of mean and median beta from page 6 of this Schedule.

Sources of Information:
Stocks, Bonds, Bills, and Inflation - 2019 SBBI Yearbook, John Wiley & Sons, Inc.
Value Line Summary and Index
Blue Chip Financial Forecasts, January 1, 2020 and December 1, 2019
Bloomberg Professional Services

Jersey Central Power & Light Company
Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seventeen Electric Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Six Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Advanced Disposal	0.75	0.68	0.71	9.54 %	2.70 %	9.47 %	10.17 %	9.82 %
Compass Diversified	0.85	0.92	0.88	9.54	2.70	11.10	11.38	11.24
Kellogg	0.65	0.65	0.65	9.54	2.70	8.90	9.74	9.32
Altria Group	0.70	0.78	0.74	9.54	2.70	9.76	10.38	10.07
Smucker (J.M.) Co.	0.70	0.62	0.66	9.54	2.70	9.00	9.81	9.40
Walmart Inc.	0.75	0.77	0.76	9.54	2.70	9.95	10.52	10.24
Mean			0.73			9.70 %	10.33 %	10.02 %
Median			0.73			9.62 %	10.27 %	9.95 %
Average of Mean and Median			0.73			9.66 %	10.30 %	9.99 %

Notes:
(1) From note 1 of page 2 of Schedule DWD-4.
(2) From note 2 of page 2 of Schedule DWD-4.
(3) Average of CAPM and ECAPM cost rates.

Jersey Central Power & Light Company
Derivation of Investment Risk Adjustment Based upon
Ibbotson Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on October 31, 2019 (1) (millions)	[1] (times larger)	[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	Jersey Central Power & Light Company	$ 3,201.417		5	1.28%	
2.	Proxy Group of Seventeen Electric Companies	$ 17,872.855	5.6 x	2	0.52%	0.76%

	[A] Decile	[B] Market Capitalization of Smallest Company (millions)	[C] Market Capitalization of Largest Company (millions)	[D] Size Premium (Return in Excess of CAPM)*
Largest	1	$ 29,428.909	$ 1,073,390.566	-0.30%
	2	13,512.960	29,022.867	0.52%
	3	7,275.967	13,455.802	0.81%
	4	4,504.066	7,524.230	0.85%
	5	2,996.003	4,503.549	1.28%
	6	1,961.831	2,992.251	1.50%
	7	1,292.791	1,960.201	1.58%
	8	730.047	1,292.224	1.80%
	9	325.360	727.843	2.46%
Smallest	10	2.455	321.578	5.22%

*From 2019 Duff & Phelps Cost of Capital Navigator

Notes:
(1) From page 2 of this Schedule.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.76% in Column [4], Line No. 2 is derived as follows 0.76% = 1.28% - 0.52%.

Jersey Central Power & Light Company
Market Capitalization of Jersey Central Power & Light Company and the
Proxy Group of Seventeen Electric Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2018 (millions)	[2] Book Value per Share at Fiscal Year End 2018 (1)	[3] Total Common Equity at Fiscal Year End 2018 (millions)	[4] Closing Stock Market Price on December 31, 2019	[5] Market-to-Book Ratio on December 31, 2019 (2)	[6] Market Capitalization on December 31, 2019 (3) (millions)
Jersey Central Power & Light Company		NA	NA	1,372.232 (4)	NA		
Based upon Proxy Group of Seventeen Electric Companies						233.3 (5)	$ 3,201.417 (6)
Proxy Group of Seventeen Electric Companies							
ALLETE, Inc.	NYSE	51.519	$ 41.844	$ 2,155.800	$ 81.170	194.0 %	$ 4,181.833
Alliant Energy Corporation	NYSE	236.063	19.426	4,585.700	54.720	281.7	12,917.383
American Electric Power Co., Inc.	NYSE	493.246	38.641	19,059.400	94.510	244.6	46,616.668
Avista Corporation	NYSE	65.688	26.994	1,773.220	48.090	178.2	3,158.953
Duke Energy Corporation	NYSE	727.011	60.270	43,817.000	91.210	151.3	66,310.663
Edison International	NYSE	325.811	32.101	10,459.000	75.410	234.9	24,569.423
Entergy Corporation	NYSE	189.581	46.652	8,844.305	119.800	256.8	22,711.745
Eversource Energy	NYSE	316.411	36.303	11,486.817	85.070	234.3	26,917.082
FirstEnergy Corp.	NYSE	511.915	13.172	6,743.000	48.600	369.0	24,879.091
IDACORP, Inc.	NYSE	50.383	47.046	2,370.360	106.800	227.0	5,380.943
NorthWestern Corporation	NYSE	53.889	36.044	1,942.382	71.670	198.8	3,862.254
OGE Energy Corporation	NYSE	199.732	20.052	4,005.100	44.470	221.8	8,882.096
Otter Tail Corporation	NYSE	39.665	18.376	728.863	51.290	279.1	2,034.412
Pinnacle West Capital Corp.	NYSE	112.160	46.567	5,222.915	89.930	193.1	10,086.539
PNM Resources, Inc.	NYSE	79.654	21.197	1,688.382	50.710	239.2	4,039.235
Portland General Electric Co.	NYSE	89.268	28.073	2,506.000	55.790	198.7	4,980.259
Xcel Energy, Inc.	NYSE	508.898	24.017	12,222.000	63.490	264.4	32,309.961
Average		238.288	$ 32.751	$ 8,212.367	$ 72.514	233.3 %	$ 17,872.855

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by requested equity ratio.
(5) The market-to-book ratio of Jersey Central Power & Light Company on December 31, 2019 is assumed to be equal to the market-to-book ratio of Proxy Group of Seventeen Electric Companies on December 31, 2019 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2018 Annual Forms 10K
yahoo.finance.com

Jersey Central Power & Light Company
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances since 2003

		[Column 1]	[Column 2]	[Column 3]	[Column 4]	[Column 5]	[Column 6]	[Column 7]	[Column 8]	[Column 9]	[Column 10]
Fiscal Year	Transaction (1)	Shares Issued	Market Price per Share	Average Offering Price per Share	Market Pressure (2)	Underwriting Discount	Net Proceeds per Share (3)	Gross Equity Issue before Costs (4)	Total Net Proceeds (5)	Total Flotation Costs (6)	Flotation Cost Percentage (7)
9/11/2003	Equity Offering	32,200,000	$ 31.1000	$ 30.0000	$ 1.10	$ 0.975	$ 29.0250	$ 1,001,420,000	$ 934,605,000	$ 66,815,000	6.67%
								$ 1,001,420,000	$ 934,605,000	$ 66,815,000	6.67%

Flotation Cost Adjustment

	Average Dividend Yield	Average Projected EPS Growth Rate	Adjusted Dividend Yield	Average DCF Cost Rate Unadjusted for Flotation (8)	DCF Cost Rate Adjusted for Flotation (9)	Flotation Cost Adjustment (10)
Proxy Group of Seventeen Electric Companies	3.05 %	5.04 %	3.13 %	8.17 %	8.39 %	0.22 %

See page 2 of this Schedule for notes.

Source of Information: Company SEC filings

Jersey Central Power & Light Company
Notes to Accompany the
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

(1) FirstEnergy 424B5 filing, 9/12/2003.

(2) Column 2 – Column 3.

(3) Column 2 – the sum of columns 4 and 5.

(4) Column 1 * Column 2.

(5) Column1 * Column 6.

(6) Column1 * (the sum of columns 4 and 5).

(7) (Column 7 – Column 8) divided by Column 7.

(8) Using the average growth rate from Schedule DWD-2.

(9) Adjustment for flotation costs based on adjusting the average DCF constant growth cost rate in accordance with the following:

$$K = \frac{D(1+0.5g)}{P(1-F)} + g,$$

where g is the growth factor and F is the percentage of flotation costs.

(10) Flotation cost adjustment of 0.22% equals the difference between the flotation adjusted average DCF cost rate of 8.39% and the unadjusted average DCF cost rate of 8.17% of the Utility Proxy Group.

Source of Information:

SEC Form 424B5 filing 9/12/2003

EXHIBIT JC-11

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Stephanie R. Zieger

On

Cost of Service/Class Allocation

REDACTED (PUBLIC VERSION)

DIRECT TESTIMONY OF STEPHANIE R. ZIEGER ON BEHALF OF JERSEY CENTRAL POWER & LIGHT COMPANY

I. <u>Background</u>

Q. Please state your name and business address.

A. My name is Stephanie R. Zieger. My business address is 2800 Pottsville Pike, Reading, PA 19605.

Q. By whom are you employed, what is your role and what are your responsibilities?

A. I am employed by FirstEnergy Service Company, as an Analyst within the Rates and Regulatory Affairs Department. In this role, I provide analytical support for regulatory proceedings to various of FirstEnergy Corp.'s regulated operating companies, including Jersey Central Power & Light Company ("JCP&L" or the "Company"). My credentials are attached in Appendix A.

Q. Have you previously testified in proceedings before the Board of Public Utilities ("Board" or "BPU")?

A. No, I have not previously testified in a proceeding before the Board.

II. <u>Purpose of Testimony</u>

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying in this proceeding on behalf of JCP&L in support of its base rate filing with the Board.

Q. What is the purpose of your direct testimony in this processing?

A. The purpose of my testimony is two-fold. First, I will describe the Cost of Service Study ("COSS") which complies with the Board's Order in the Company's 2012 base rate case in BPU Docket No. ER12111052 ("Complied COSS"). In that proceeding, the Board ordered the Company to file in its next base rate case a study similar to its filing in the 2012 case, but with revisions based on Board Staff's recommended methodology:

> Accordingly, the Board **ORDERS** the Company to submit in its next base rate petition a cost of service study pursuant to the prescriptions detailed in Exhibit S-61, pages 1 through 8, attached hereto as Attachment B.[1]

Although the Stipulation of Settlement and Board Order in the Company's 2016 base rate case (Docket No. ER16040383) did not contain a similar requirement, the Company is nonetheless providing a COSS that is consistent with Board Staff's recommended methodology.

Second, my testimony describes the principles, methodology, and data used in the present cost of service study and the proposed modifications, and how these relate to the methods that the Board directed the Company to use in studies in prior base rate cases. In this regard, I provide a description of the inputs used to prepare, and the accompanying results of, the Company's proposed alternative cost of service study ("Proposed COSS").

Q. Why is a cost of service study performed?

A. The primary objective of a cost of service study is to apportion the Company's revenue requirement to various customer groups based on the principles of cost

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[1] *I/M/O the Verified Petition of Jersey Central Power & Light Company for Review and Approval of an Increase in and Adjustments to Its Unbundled Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith, et al*., BPU Docket No. ER12111052, Order dated March 26, 2015, at p. 76 ("2015 Rate Case Order").

causation or responsibility. In a cost of service study, the utility's cost of providing service is functionalized, classified and allocated among various classes of service. The results of the cost of service study are used as a guide in establishing rates that recover the Company's total revenue requirement, subject to assumptions such as delivery volumes and customer counts. Costs are allocated to rate classes by selecting allocators based on causal relationships between the customers' demands, load profiles and usage characteristics and costs the Company incurs to furnish service to each rate class.

Q. Do you agree with the Complied COSS performed using Board Staff's recommended methodology?

A. No. I do not agree with some of the assumptions or the results of the Complied COSS. Board Staff's prescribed methodology is not supported by evidence of how the Company's electric distribution facilities are planned and constructed, nor does it strongly conform to generally accepted cost causation principles.

Q. Is the Company proposing an alternative cost of service study?

A. Yes. The Company's Proposed COSS incorporates recommended modifications to the Complied COSS, as I explain subsequently in my testimony.

Q. Please identify and briefly describe the schedules you are sponsoring.

A. The schedules I am sponsoring are as follows:

<u>Schedule SRZ-1 (Confidential and Redacted versions)</u> contains the Complied COSS results based on the Board Staff's method of classification and allocation. This schedule identifies the detailed allocation results for each cost item.

Schedule SRZ-2 **(Confidential and Redacted versions)** contains the Company's Proposed COSS results based on an alternative method of classification and allocation. This schedule identifies the detailed allocation results for each cost item.

Schedule SRZ–3 (Confidential and Redacted versions) contains the supporting work papers for the sub-functionalization, classification, and allocation factors used in both the Complied COSS and the Proposed COSS. These work papers are described briefly later in my testimony.

Schedule SRZ-4 (Confidential and Redacted versions) contains certain relevant copies of the Company's distribution engineering practices.

Schedule SRZ-5 contains certain relevant pages of the NARUC Cost Allocation Manual.

Q. Please describe the organization of your testimony.

A. Sections I & II describe my background, the purpose of my testimony and the schedules I am sponsoring. The remainder of my testimony starts with Section III. In this section, I describe the general cost of service study process and a detailed description of the Complied COSS. Section IV presents the results of the Complied COSS. Section V describes changes made to the model that support the results of the Company's Proposed COSS. Section VI presents the results of the Proposed COSS.

III. Description of the Cost of Service Study Process

Q. Please briefly describe the steps used in performing a cost of service study.

A. The following three-step process is commonly used to assign costs to each rate class based on cost-causation:

i. “Functionalization” is the process of arranging cost data by major operational category (e.g., generation, transmission, distribution) and its associated business functions in order to facilitate a determination as to which rate classes share responsibility for each of the assets and costs. The FERC Uniform Systems of Accounts is the starting point of the functionalization process. In some instances, it is necessary to further subdivide a major function into sub-functions, for example, by recognizing different voltage levels and separating plant data by primary and secondary.

ii. “Classification” is the process of assigning the functionalized costs as customer-related or demand-related to facilitate assigning them to rate classes in accordance with identifiable characteristics. Demand-related costs are fixed costs dependent on kilowatt (kW) requirements and associated with the demands on the Company’s distribution facilities. Customer-related costs are those that vary based on the number of customers served by JCP&L. Some cost accounts may fall into more than one category.

iii. “Allocation” is the process of assigning the classified costs to each rate class based upon each class’s contribution to that specific cost component. For example, customer-related costs vary on the basis of the number of customers (or customer accounts) and, therefore, are allocated based on the number of customers (or customer accounts) on a rate class. The goal of cost allocation is to spread the costs in a fair manner, in a way that impacts the behavior patterns of the cost objects.

Q. What rate classes were used in both the Complied and Proposed COSS?

A. In preparing the COSS, the Company’s total cost of service was assigned or allocated among the following rate classes:

- Residential Service (RS);

- Residential Time-of-Day Service (RT);
- General Service Secondary (GS);
- General Service Secondary Time-of-Day (GST);
- General Service Primary (GP);
- General Service Transmission (GT), excluding Special Provision D;
- General Service Transmission, Special Provision D; and
- Lighting (LTG).

For purposes of performing the COSSs, certain rate classes were combined because their cost and usage characteristics are similar. Rate class RT is a composite of customers that take Residential Time-of-Day Service and Residential Geothermal & Heat Pump Service (RGT). Outdoor Lighting (OL), Sodium Vapor Street Lighting Service (SVL), LED, Mercury Vapor Street Lighting Service (MVL) and Incandescent Street Lighting Service (ISL) are combined in rate class LTG.

Also, Rate class GT is comprised of all General Service Transmission customers 34.5kv - 230kv (excluding GT Special Provision D). Rate Class GT, Special Provision D is separated into a separate sub-class.

Q. Please explain why General Service Transmission Special Provision D was separated into a subclass of General Service Transmission.

A. In the Company's 2012 base rate case, the Board, in its final order, directed the Company to break out Special Provision D into a separate sub-class for cost of service study purposes. More specifically, the order provided:

> The Board further **DIRECTS** the Company to break out Special Provision D into a discrete GT sub-class for cost of service study purposes in its next base rate filing ….[2]

[2] 2015 Rate Case Order, at p. 78.

Q. **Please describe the model the Company used to perform the COSS in this proceeding.**

A. The model used by the Company to perform the COSS is a Microsoft Excel application developed by JCP&L.

Q. **Please describe Schedule SRZ-1.**

A. This schedule contains the summary of the Complied COSS results. It displays summary level information related to the calculation of each rate class's rate of return at present revenue levels.

Q. **Please describe Schedule SRZ-3.**

A. This schedule contains work papers that support the development of both the Complied COSS and the Proposed COSS. The work papers are listed below and are accompanied by a brief explanation of each:

1) WP 1 (CP Demands) displays the average of the four summer monthly coincident peak ("CP") demands, by rate class. The use of the CP is based on Board Staff's methodology.
2) WP 2 (MWh) displays the monthly weather adjusted billing month delivery net system requirements in MWh, by rate class.
3) WP 3 (Customer Counts) displays customer counts, by rate class.
4) WP 4 (Distribution Revenues) displays weather-adjusted revenues, by rate class.
5) WP 5 (BPU Staff Primary/Secondary Segmentation [Accounts 364-367]) displays distribution assets in FERC accounts 364-367 by sub-function (two discrete categories, primary facilities and secondary facilities). The segmentation is based on Board Staff's methodology.

6) WP 6 (Voltage-Specific Load Factors) shows the calculation of the load factors by voltage levels using coincident peaks.

7) WP 7 (Customer Account Expenses) allocates supervision and miscellaneous customer account expenses to rate classes.

8) WP 8 (Non-Consumption Revenue) allocates to rate classes the revenue that is derived from sources other than customers' use of electricity.

9) WP 9 (BPU Staff Meter Plant Cost Allocation) allocates the cost of metering equipment to rate classes and is based on Board Staff's methodology.

10) WP 10 (O&M Labor) allocates labor expense as a percent of total O&M.

11) WP 11 (PowerGuard Revenue) displays PowerGuard revenues (Account 456) by rate class.

12) WP 12 (NCD) displays the average of the four summer monthly non-coincident peak demands ("NCD"), by rate class. The use of the NCD is the Company's recommended methodology.

13) WP 13 (Voltage Specific Load Factors) shows the calculation of the load factors by voltage levels using non-coincident peaks.

14) WP 14 (Company Recommended Primary/Secondary Segmentation [Accounts 364-367]) displays distribution assets in FERC accounts 364-367 by sub-function (two discrete categories, primary facilities and secondary facilities). The segmentation is based on the Company's methodology.

15) WP 15 (Company Recommended Meter Plant Cost Allocation) allocates the cost of metering equipment to rate classes and is based on the Company's methodology.

16) WP 16 (Average Circuit Data) displays average number of customers per circuit, by circuit type.

17) WP 17 (Primary/Secondary Segmentation [Accounts 580, 589, 590]) shows the allocation calculation of the distribution assets in FERC accounts 580, 589, 590 based on both the Board Staff and the Company's methodology.

18) WP 18 (Service Cost Allocation) allocates the cost of service costs to rate classes and is based on the Company's methodology.

Q. Please describe the function(s) included in the Complied COSS.

A. The only function in this study is "distribution," which comprises the rate base and operating and maintenance expenses of the Company's distribution system, customer premises facilities and customer accounting, billing and information systems. All of the costs functionalized as distribution were derived from the costs recorded in accounts that the Company maintains in accordance with the FERC's Uniform System of Accounts. JCP&L witness Carol A. Pittavino (Exhibit JC-4) provided functionalized cost data which was used in this study.

Q. Is there a need to further divide the distribution function into sub-functions?

A. Yes. Functionalized distribution plant data does not provide adequate detail because the services and associated costs provided to customers depends on the voltage level of their interconnection. Therefore, it is necessary to sub-functionalize distribution plant costs recorded in FERC Accounts 364 – 367 based on voltage peak responsibility to more equitably allocate such costs among rate classes. As previously mentioned, for the Complied COSS, the Company has followed the methodologies as described in Exhibit S-61 from the 2012 base rate case. As such, plant balances of FERC Accounts 364, 365, and 367 were subdivided 50% to primary service voltage rate classes ("PRI") and 50% to secondary service voltage rate classes ("SEC"), and the plant balance of FERC Account 366 was subdivided 90% to PRI and 10% to SEC, as shown in Schedule SRZ-3, WP 5.

Q. Are you able to provide the rationale for the Board Staff's sub-functionalization of these distribution plant costs?

A. No. Board Staff provided no support as to how these segmentation ratios were derived.

Q. Do you agree with this sub-functionalization?

A. No. I discuss this issue below in regard to the Proposed COSS.

Q. What classification method was used in performing the Complied COSS?

A. The Complied COSS was prepared consistent with the classification methodologies prescribed by BPU Staff and accepted by the Board in the Company's 2012 base rate case, which generally relies on the Average and Excess method to classify costs.

Q. Please explain the long-standing Board approved Average and Excess method.

A. The Average and Excess method is a two-part formula that is used to assign energy-related and demand-related costs. This method has historically been used by many utilities to apportion between those generation costs expended to meet the company's peak demand requirements and those generation costs expended to meet the company's energy requirements. Under the Board Staff's Average and Excess method, the energy-related component of fixed costs is determined to be equal to the system annual load factor. The energy-related costs, thus determined, are then allocated to the various rate classes based on the respective level of consumption in each classification. The demand-related portion of a cost is calculated by multiplying the cost to be allocated by 1.00 minus the aggregate load factor.

Demand-related costs were then allocated to the various rate classes, based on the respective non-coincident demands ("NCD") of those classifications.

Q. Do you believe the Average and Excess method accurately reflects cost causation for the Company's distribution system costs?

A. No. I discuss this issue below in regard to the Proposed COSS.

Q. In the Complied COSS, were any changes made to the allocators from previously filed methodologies?

A Yes. In the Company's 2012 base rate case, the Board took a departure from its long-standing approval of using the average of the 4 summer NCDs as the demand related allocator. To comply with Board Staff's methodology, coincident peak ("CP") was used in its place.

Q. Please describe CP and how it was determined.

A. Coincident peak is the energy demand required by a given customer or group of customers during a period of peak system demand. In this study, the summer coincident peaks were determined by using the date and hour of the JCP&L peak zonal loads for each month June - September (as reported by PJM). The demand for each rate and load profile code was reported as their monthly coincident peak value. The individual values were summed to a rate class level and divided by four to calculate the average of the four summer month's value.

Q. Do you believe the use of a CP allocator accurately reflects cost causation?

A. No. I discuss this issue below in regard to the Proposed COSS.

Q. Please describe the third step in the cost of service study process, the allocation of costs.

A. Allocation is the process of assigning costs to rate classes, based on measurable characteristics. There are two types of allocators used in the COSS: external and internal. External allocators are based on direct knowledge from data in the Company's accounting or other records. Examples of external allocators include coincident peak demand, kilowatt hours of usage and number of customer accounts. Internal allocators are based on some combination of external allocators and in some cases, other internal allocation factors. An example of an internal allocator would be a factor that allocates a particular cost in proportion to the composite allocation of the Company's total distribution plant in service. This means that the classification and allocation of total distribution plant in service must be completed before that particular cost can be classified and allocated in proportion to the composite allocation of total plant.

Q. Before discussing the manner in which rate base was classified and allocated in the COSS, please identify the major components of JCP&L's rate base.

A. Rate base is the original cost of JCP&L's investment in plant and other investment, net of accumulated depreciation, net of accumulated deferred income taxes and including certain other customary adjustments. As shown in Schedule SRZ-1, JCP&L's total rate base in this case is approximately $2.6 billion. The revenue requirement associated with rate base consists of depreciation or amortization (for depreciable/amortizable assets), property tax, property insurance, and a pre-tax return. The major components of JCP&L's rate base consist of Intangible Plant, Distribution Plant, General Plant, FirstEnergy Service Company Plant, Depreciation Reserve and Other Rate Base. I will refer to these principal components in discussing how the Company's rate base was classified and allocated in the COSS.

Q. How was each component of rate base classified and allocated among the rate classes in the Complied COSS?

A. Each component of the rate base was classified and allocated as follows:

<u>Electric Utility Plant</u>

Intangible Plant (Accounts 301-303) represents the costs associated with the organization of the Company as a business entity, the franchises and consents needed to do business and other intangible assets. The Average and Excess method was used to classify these costs, which were then allocated among rate classes on the basis of demand and energy.

Distribution Plant (Accounts 360-374) represents the costs associated with tangible plant that carries the electricity from the transmission system to consumers. The sub-functionalization and allocation of costs for accounts 360-370 are based on Board Staff's Methodology, which methodology is not supported by the Company. The costs recorded in each account in this component were classified and allocated as follows:

- Accounts 360-367 include costs associated with land, structures, station equipment, poles, towers, fixtures, conductors, and conduit systems. Costs were identified as either primary or secondary voltage, as prescribed by Board Staff and discussed earlier in testimony. These items were then classified between demand and energy using the Average and Excess method and allocated using applicable demand or energy allocators.
- Account 368 includes costs associated with line transformers. These costs were identified as being 100% secondary, and then classified between demand and energy using the Average and Excess method and allocated using applicable demand or energy allocators.

- Account 369 includes the cost of customer service lines. These costs were classified equally as customer-related and demand-related and allocated using applicable customer counts or demand allocators.
- Account 370 includes meter costs. This account was allocated as prescribed by Board Staff's methodology. The allocation and classification inputs are detailed in Schedule SRZ-3, WP 9.
- Accounts 371 and 373 contain costs associated with installations on customer premises. These costs were directly assigned to lighting customers.

General Plant (Accounts 389-399) includes primarily structures and improvements, tools and equipment and communication equipment, along with other assets used to support all functions of the Company. These items were classified between demand and energy using the Average and Excess method and allocated using applicable demand or energy allocators.

Service Company Plant

FirstEnergy Service Company Plant is the FirstEnergy Service Company investment allocated to JCP&L. FirstEnergy Service Company assets were classified between demand and energy using the Average and Excess method and allocated using applicable demand or energy allocators.

Accumulated Depreciation Reserve is the total accrued annual depreciation expense of each depreciable asset account. Each component of the depreciation reserve was classified and allocated in the same ratio as the asset(s) to which it relates.

Other Rate Base Items include additions or deductions made in calculating the Company's distribution rate base, as follows:

- Customer Advances for Construction, Accumulated Deferred Income Taxes ("ADIT"), Net/Loss on Required Debt, Materials and Supplies, Excess Cost of Removal, Customer Refunds, Net Operating Losses and Property-Related Unprotected Amortization were all classified and allocated among rate classes in proportion to distribution plant in service.

- Customer Deposits were classified as customer-related costs and, therefore, were allocated based on customer counts.
- Cash working capital was classified and allocated based on operating and maintenance expenses excluding administrative and general expenses.
- Consolidated Tax Adjustment was classified and allocated based on rate base plant in service
- Net Operating Reserves was classified and allocated based on the labor portion of Total distribution O&M and Total Customer Service and A&G Expenses

Q. What are the major expense categories for JCP&L that were used in the COSS?

A. The major expense categories for JCP&L that were used in the COSS consist of distribution operating and maintenance expenses (Accounts 580–598); customer account expenses (Accounts 901-905); customer service expenses (Accounts 907-910); administrative and general (A&G) expenses (Accounts 920–935); depreciation expense (Account 403); amortization expense (Accounts 404 & 407), taxes other than income (Account 408); and income tax expense.

Q. How did you classify each component of expense and allocate it among the rate classes in the Complied COSS?

A. Each category of expense was classified and allocated as follows:

- Distribution operating and maintenance expenses (Accounts 580-598) were classified and allocated consistent with the rate base items with which the expenses are related. For example, Account 583 - Station Expenses were allocated based on the classification and allocation of Account 362 – Station Equipment.

- Supervision (Account 901) and Misc. customer-account (Account 905) costs were allocated consistent with the methodology approved in the 2012 case, as shown in Schedule SRZ-3, WP 8.
- Meter Reading Expenses (Account 902) and Customer Records and Collection Expenses (Account 903) were allocated based on Account 370, as prescribed by Board Staff's methodology.
- Uncollectible expenses (Account 904) were classified as 100% energy and allocated to the classes based on MWh, as prescribed by Board Staff's methodology.
- Customer service costs (Accounts 907 – 910) and Sales Expense (Account 911) were classified as either demand or energy-related, using the Average and Excess method, and allocated to all rate classes (excluding rate class GT) using the applicable allocator.
- A&G expenses (Accounts 920 – 932) include primarily A&G salaries, office supplies and expenses, outside services, pensions and benefits, and miscellaneous expense. These costs were allocated to rate class GT by assigning that portion of total A&G equivalent to the percentage of total distribution plant directly allocated to the class as demand related. The remaining costs (non-GT) were classified as either demand or energy-related, using the Average and Excess method, and the costs thus classified were allocated to rate classes using the applicable allocator.
- Depreciation expense was classified and allocated among rate classes in the same ratio as the assets to which the annual depreciation relates.
- Amortization expenses relating to cost of removal, losses or gains on the sale of assets and vegetation management services were classified and allocated in the same ratio as total distribution plant in service. Amortization expenses relating to storm and universal service costs were

classified between demand and energy using the Average and Excess method and allocated using applicable demand or energy allocators.

- Taxes other than income tax include property tax, payroll and unemployment tax and other similar taxes that do not vary in proportion to income or revenue. Property tax and other property-related taxes were classified and allocated in proportion to the classification and allocation of total plant in service. Payroll and unemployment tax was classified and allocated in proportion to labor expense.
- Income tax expense was computed based on revenue at present tax rates then classified and allocated among rate classes in proportion to pre-tax income.

Q. How did you classify other operating revenues and allocate such revenues among the rate classes?

A. Other operating revenues consist of late payment charges, non-consumption service fees (field collection charge, reconnection service charge, temporary service charge, etc.), rent from electric property, power guard revenues and other miscellaneous revenues. Late payment fee revenue, non-consumption service fee revenue and power guard revenue were allocated to rate classes based on proportions of historical data. Rent from electric property and other miscellaneous revenues were classified and allocated based on the ratio of distribution plant in service.

Q. Please explain the layout of the Complied COSS (Schedule SRZ-1).

A. Page 1, at lines 1-25, of Schedule SRZ-1 summarizes the net operating income and resulting rate of return and unitized rate of return for each rate class at present tariff charges.

Pages 2 - 37 of Schedule SRZ-1 display the detailed allocated and classified costs supporting lines 1-21 of page 1. Additionally, the method of classification/ allocation is displayed for each account in the study.

Pages 38 - 47 of Schedule SRZ-1 display the input tabs used in the model.

IV. Results of Complied COSS

Q. Please summarize the results of the Complied COSS.

A. The Company's total present net operating income of $67.28 million represents a 2.59% return on rate base of $2.6 billion.

Table 1 below summarizes the rates of return and unitized rates of return prior to the proposed rate changes. Rate classes RS, GST, and GP are presently earning less than the overall distribution rate of return, while Rate classes RT, GS, GT, and LTG are earning higher rates of return than the overall distribution rate of return.

Table 1: Complied COSS Summary at Present Revenues

Rate	Rate of Return	Unitized
RS	1.40%	0.54
RT	3.10%	1.20
GS	4.41%	1.70
GST	1.77%	0.68
GP	1.90%	0.73
GT	19.91%	7.69
LTG	2.71%	1.05
Total	**2.59%**	**1.00**

V. <u>Description of Proposed COSS</u>

Q. Why did you also prepare the Proposed COSS?

A. I do not agree with Board Staff's preferred cost of service methodology. Board Staff's methodology is inconsistent with other widely-accepted cost of service models. In sum, the Average and Excess method does not accurately reflect cost causation for the Company's distribution system costs.

Q. Can you briefly summarize the modifications in the Proposed COSS?

A. Yes. First, I propose to use circuit data to support the segmentation of primary and secondary voltage components for FERC Accounts 364-367. As I will describe below, the Company's data allow for the identification of portions of JCP&L's circuits that solely support secondary customers, which the Company believes allows for a more precise segmentation than the methodology used in the Complied COSS. Second, I propose an alternative segmentation for FERC Accounts 360 – 362 that differentiates distribution substation items and electric distribution items in these accounts. I propose that FERC Account 362 – Station Equipment be segmented 100% to primary. For FERC Accounts 360 – Land & Land Rights and 361 – Structures & Improvements, substation line items and electric distribution line items were separately identified and segmented, and a weighted composite segmentation factor was developed for each account. Third, I propose to refine the computation of the customer component of FERC Account 370 (Meters) by including the cost of meter hardware, and the labor, supporting equipment, and associated overheads required to install them. By including these costs, I am proposing to treat FERC Account 370 in a manner that is consistent with how other

FERC Accounts are treated by the Company. The Complied COSS considers only materials costs, which represent only a portion of the costs in FERC Account 370. Fourth, I propose to classify costs in Account 368 as 100% demand related and to use NCD as an alternative allocator and reduce the load factor used by one-half when applying the Average and Excess methodology. Lastly, I propose a computation of the customer component of FERC Account 369 (Services). This computation follows a methodology that is similar to the Company's methodology for meters.

Q. Please describe the first modification in the Proposed COSS.

A. The first modification in the Proposed COSS relates to the segmentation of the costs in FERC Accounts 364-367 into their primary and secondary voltage components.

Q. What do you mean by segmentation?

A. In this context, the term segmentation refers to the assignment of distribution plant costs to primary and secondary customers. As described above, the functionalization step in a COSS generally involves the assignment of various costs into their different components by major operational category (that is, generation, transmission, and distribution). Here, I am talking about additional steps that may be taken to functionalize costs in a way that recognizes the use of certain types of distribution plant assets by specific groups of customers. To avoid confusion, I use the term segmentation in this section to refer to the further functionalization of distribution plant costs to primary and secondary customers.

Q. Why is it necessary to perform such a segmentation between primary and secondary customers?

A. JCP&L proposes to use this segmentation because the service requirements of primary and secondary customers differ substantially, and the Company believes it is important to capture these differences in the process of assigning costs to each group. For example, primary distribution customers do not use the distribution system components that are required to transform and transmit electricity to secondary customers. Therefore, consistent with cost causation principles, they should not be assigned responsibility for the costs of assets used to provide these services.

Q. What methodology does the Complied COSS use to segment the costs of Accounts 364-367 into their primary and secondary voltage components?

A. The Complied COSS uses a default assignment of primary and secondary costs (50% to primary and 50% to secondary) to accounts 364, 365, and 367. A similar default assignment is used for Account 366, which is subdivided 90% to primary and 10% to secondary.

Q. Please describe the method you propose to use to segment costs in Accounts 364-367 into their primary and secondary voltage components.

A. The data used by the Company in the Proposed COSS allows for the identification of four types of circuits based on the types of customers those circuits serve: circuits that serve only primary customers, circuits that serve only secondary customers, circuits that serve both primary and secondary customers, and circuits that do not directly serve any customers but can be used to tie together two circuits in proximity during an outage event or during other similar situations. The Company proposes to use the length of these circuits to segment costs in these accounts between their primary and secondary components.

Q. What data did you use to develop your segmentation of Accounts 364-367?

A. In 2016, JCP&L performed a circuit study, which revealed that the Company had a total of 1,173 distribution circuits in its service territory. Of those circuits, JCP&L identified a total of 27 that serve only primary customers, and 851 circuits that serve only secondary customers. The Company also identified 276 circuits that serve both primary and secondary customers. The number of circuits and the circuit length for of these four types of circuits is summarized below in Table 2.

Table 2: JCP&L Circuit Count and Length, by type of Customer Served

Circuit Type	Circuit Count	Circuit Count Percentage	Total Circuit Length (Miles)	Total Circuit Length Percentage
Primary customers only	27	2.3%	9	0.0%
Secondary customers only	851	72.5%	13,424	69.5%
Both primary and secondary customers	276	23.5%	5,868	30.4%
Not directly serving customers	19	1.6%	2	0.0%
Total	**1,173**	**100.0%**	**19,303**	**100.0%**

This data was used to estimate the portion of circuits that serve only secondary customers. Based on circuit count, this percentage of circuits serving only secondary customers is equal to 851/1173, or 72.6%. Using circuit length, however, this percentage of circuits serving only secondary customers is equal to 13424/19303, or 69.5%. To be conservative, the Company proposes to segment

69.5% of costs in FERC Accounts 364-367 to secondary voltage customers, and the remaining 30.5% to both primary and secondary customers.

Q. Does this circuit estimate represent your recommendation to segment the costs associated to Accounts 364-367?

A. Yes, the Proposed COSS uses this breakdown to segment the costs in FERC accounts 364-367. This conservatively assumes that the circuits that serve both primary and secondary customers are similar enough both in terms of relative design and cost as circuits that serve only primary metered customers.

Q. Is it fair to assume that circuits that serve only secondary customers are similar in terms of both design and cost to circuits that serve both primary and secondary customers?

A. I believe this to be true. However, as I am not a distribution engineer, the study was prepared by and I relied on the expertise of JCP&L's engineering staff.

Q. Is there a schedule that provides additional support for this segmentation?

A. Yes, WP 16 of Schedule SRZ-3 was provided by JCP&L's distribution planning department. It shows that a circuit serving both primary and secondary metered customers serves, on average, 1.4 primary metered customers and 989 secondary metered customers. A circuit serving only secondary metered customers serves on average 983 customers. This supports JCP&L's belief that these two types of circuits are reasonably comparable in terms of cost and design for purposes of performing this study.

Q. Is it appropriate to rely on the circuit analysis that was performed in 2016?

A. Yes, I believe it to be appropriate. The analysis was performed less than five years ago. According to the information that I have been provided by JCP&L's engineering staff, the circuit additions and/or modifications that have occurred since this time are not expected to have materially altered the results from the 2016 analysis.

Q. Please describe the modifications that you propose to the segmentation of FERC Accounts 360-362.

A. FERC Account 362 - Station Equipment was segmented 100% to primary. It is comprised of substation equipment, which equipment is used to provide service to both primary and secondary distribution customers. Therefore, the cost of this equipment properly should be borne by all distribution customers. Applying a 100% primary segmentation (which allocates the costs across all primary and secondary distribution customers) accomplishes this end. Also, to be consistent with the segmentation of FERC Account 362, FERC Account 582 - Station Expense was segmented in the same manner.

Regarding FERC Account 360 - Land & Land Rights and FERC Account 361 - Structure & Improvements, the Company reviewed line-item detail for each account. Line-items in each account that are associated with substations were identified and segmented 100% to primary (consistent with FERC Account 362). Line-items in each account that are associated with electric distribution were identified and segmented between primary and secondary, relying on JCP&L's 2016 circuit study for FERC Accounts 364-367. The resulting allocations were then aggregated and a weighted composite factor was developed for each account.

Q. Do you also make modifications to the allocation of costs in FERC Account 370 – Meters?

A. Yes, the Proposed COSS also modifies the classification of costs in FERC Account 370.

Q. Please describe what information is being used to classify costs in FERC Account 370.

A. The Proposed COSS uses three pieces of information to classify costs. The first are data on the current moving average price and estimated installation cost for all meters that are installed in JCP&L's service territory since 2015. Each material cost can be identified by a part number that is labeled a 'material code.' The second are data on the costs JCP&L incurs to procure, store, and install meters, that are separate from the cost of the hardware itself. The third is updated information on the number of meters that are currently installed in JCP&L's territory as of September 2019, by rate class.

Q. How are these three pieces of data used in the Proposed COSS?

A. The moving average price is used to calculate the minimum and average material costs. The costs associated with storing and installing meters were then estimated to capture the fully-loaded costs of procuring and installing a meter. The number of meters currently installed in the field, by material code and rate class, is used to weight the costs of individual parts to develop a minimum and average cost by rate class. These three pieces of data are then used to classify the costs in Account 370 into customer and demand components. The customer component is estimated as the ratio of the minimum meter cost to the average meter cost by rate class, and the remainder is classified as the demand component. This methodology is consistent with the Complied COSS; however, it relies on the total installed cost, rather than just the material cost for the meter.

Q. Why is it appropriate to consider the fully-loaded cost of meters in the classification of costs in FERC Account 370?

A. As noted previously, the Complied COSS considers the costs of the physical meter only. But these represent only a portion of the costs of procuring and installing a meter. In addition to purchasing the meter, the company incurs labor and other overhead costs when providing meters to customers, including, for example, the costs associated with storing the meters, the labor costs associated with sending a field personnel to install the meter, and the equipment that the field personnel use, such as a vehicle and tools.

Q. Is the inclusion of labor, supporting equipment, and related overhead costs unique to Account 370?

A. No. JCP&L uses fully-loaded costs when classifying other accounts that include long-lived capital investments being made on behalf of customers.

Q. Can you provide a description of each individual component of the total cost of procuring and installing a meter?

A. The total installation cost is the sum of three components: material costs, labor costs, and supporting equipment costs. The material costs represent the direct and indirect cost to procure the physical meter. Direct material costs refer to the purchase price of the physical materials, while indirect material costs include material handling and related A&G costs. The direct material costs used in this analysis reflects the current moving average price for each meter.

The labor costs include direct and indirect costs associated with installing a meter on the customer's premises. The direct labor costs include the hourly wage of the crew performing the installation, while indirect labor costs refer to associated costs such as payroll benefits, A&G, and pension services, all of which are required to support the direct labor.

Finally, the supporting equipment cost refers to the costs of the vehicle to visit the customer's site and the tools required during the meter installation. The direct equipment costs refer to the cost of the equipment itself, while indirect material costs include related A&G costs.

Q. What is the next step after calculating the fully-loaded cost of each material code?

A. The next step is to use the fully-loaded cost for each material code to calculate the weighted average and minimum fully-loaded cost by rate class. To do this, the number of meters that are currently deployed in JCP&L's territory by rate class was determined. The weighted average fully-loaded cost is calculated by using the fully-loaded cost of individual parts, and weighting it based on the distribution of each part within a rate class.[3] The minimum fully-loaded meter cost is then identified as the cost of the lowest-cost material code for a specific rate class.

Q. Please explain how you classify costs in FERC Account 370.

A. JCP&L used the minimum size approach to classify the costs in Account 370 to the customer and demand components. This approach aims to identify the minimum size meter that is necessary to serve a customer for each rate class, and identifies this as the customer component of meter costs. Costs in excess of that minimum size meter are classified to the demand component.

The lowest fully-loaded meter cost was used as the minimum size component and it was compared to the average fully loaded meter cost for each rate class. To calculate the breakout between the customer and demand component, the ratio between the cost of the minimum meter and the cost of an average meter was calculated for each rate class.

Q. Is this methodology consistent with the Complied COSS?

A. Yes, it is. This is also the methodology used in the Complied COSS; however, the modifications are to incorporate fully-loaded meter cost data.

Q. To which classes did you apply this methodology in the present study?

A. I used this methodology for the RS, RT, GS, and GST classes.

Q. Please summarize the results of your classification of costs in Account 370.

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[3] To illustrate this, assume a particular rate class currently uses one of two meters: Meter A which costs $100, and Meter B which costs $200. Now assume that 90% of customers in this class have Meter A and the remaining 10% have Meter B. The weighted average meter cost for this class is estimated as $100*0.9+$200*0.1=$110.

A. The results of the analysis are shown in Table 3 below. The section at the top of the table shows the share of costs that would be assigned to the customer component, if only material costs were considered, and thus excluded labor and related overheads. The bottom section shows the customer component calculated using fully-loaded meter costs, which include labor, supporting equipment, and related overheads.

Table 3: Customer Component for select Rate Classes Using Fully-Loaded Meter Costs

	RS	RT	GS	GST
Material Only Costs				
Minimum Cost ($)	$18.25	$18.25	$18.25	$263.22
Weighted Average Cost ($)	$23.32	$88.44	$91.23	$2,328.77
Customer Component (%)	78.2%	20.6%	20.0%	11.3%
Fully Loaded Costs				
Minimum Cost ($)	$238.05	$238.05	$238.05	$1,459.87
Weighted Average Cost ($)	$248.70	$357.30	$573.18	$4,906.31
Customer Component (%)	95.7%	66.6%	41.5%	29.8%

Q. Please explain the reasons why using fully-loaded material costs results in a higher customer component when compared to the results of the Complied COSS.

A. While material costs can vary between material codes, the labor, equipment and related overhead costs represent a larger share of total costs and do not vary significantly across meter types. Accordingly, the minimum installation cost and average installation cost increase by roughly the same amount when using the Proposed COSS methodology. As a result, the minimum cost represents a larger share of the average cost in the Proposed COSS as compared to the Complied COSS.

Q. Can you next discuss the use of Non-Coincident Peak Demand (NCD) and Coincident Peak Demand (CP) and whether they are appropriate allocators for demand related costs?

A. Yes. In JCP&L's 2012 base rate, the Board's decision required the use of NCD as the allocator for demand related costs. In fact, the use of the NCD as an allocator has been upheld by the Board for decades and is consistent with the NARUC Electric Utility Cost Allocation Manual (pp. 96-97) that states that distribution facilities are "installed primarily to meet localized area loads," which are best represented by NCD.

Q. Please explain why the Company is also presenting the results of the COSS using CP as the allocator for demand related costs.

A. In the 2012 rate case, the Board ordered that, in its next rate proceeding, the Company present the results of a cost of service study using class coincident peak contributions for the allocation of the demand component in the Average and Excess method. The Complied COSS uses that methodology accordingly.

Q. Is CP considered to be an appropriate allocator for demand costs related to distribution service?

No, I do not support the use of CP as an allocator for demand related costs. Distribution facilities are sized to meet "localized area loads" because that is the load they serve. In other words, the CP for the entire system is not a relevant parameter in the appropriate design of a specific primary or secondary circuit, but rather the maximum loads of the circuit itself.

Q. What alternative allocator do you suggest JCP&L employ in the Proposed COSS?

A. I propose to use an NCD-based allocator.

Q. Can you next address the Average and Excess method of cost allocation and suggest an alternative allocation method for costs in FERC Account 368: Line Transformers?

A. Yes. There are many different cost allocation methods, but they generally fall under two categories – peak demand-related and energy-related.

Q. What do you mean by peak demand allocation methods?

A. Peak demand allocation methods use some measurement of a rate class's maximum demand and the proportion of that demand relative to the sum of all other rate classes' demands as the allocation factor for fixed costs. Coincident peak demand methods use a measure of a rate class's demand coincident with the overall system peak. For example, the use of a rate class' demand coincident with the utility's annual peak is called the 1CP method, denoting only the single highest demand coincident with the peak is the allocation basis. 3CP uses the average of the three highest monthly class peaks coincident with the system's three highest monthly peaks. There are other variations in addition to these examples.

Q. What serves as the motivation behind the peak demand approaches?

A. Peak demand methods view cost responsibility as based on the sizing of plant to reliably meet customers' needs. A utility must size its plant to be capable of meeting all of its customers' demands at all times. Because not all of a utility's equipment works all of the time, that can translate into sizing equipment larger than maximum needs or the utilization of redundant equipment.

Q. What do you mean by energy-related allocation methods?

A. Energy-related cost allocation methods use some measure of energy usage by a customer class as a basis for cost responsibility. In such case, only a class's energy use and the proportion of that energy use relative to the sum of all other classes' energy use is the allocation factor.

Q. Is the Average and Excess Method an energy-related allocation method?

A. Yes. To perform the computations, the Average and Excess method uses the class maximum demands, that is, the NCDs, the average demands for each class, and the system load factor. The system load factor is defined as the system's average demand divided by the system's peak demand and can vary between 0 and 100 percent, with most utility systems falling in the range of 40-60 percent (0.4-0.6). The allocation factor consists of two parts, an average demand factor and an "excess demand" factor. The average demand factor is a class's proportion of total average demand times the system load factor. The excess demand factor is a class's proportion of the difference between the sum of all classes' NCDs and the average system demand multiplied by 1 – minus the system load factor.

Q. How is the Average and Excess method generally used to classify utility cost of service?

It is primarily used for classifying generation costs. The Average and Excess allocator has been used because baseload generation plants have their greatest economic value through reduced costs per kilowatt-hour to those customers, which most take advantage of those lower costs. Although all customers benefit from the reduced energy costs that capitally intensive baseload generation produces, the argument has been made that the highest load factor classes should bear the burden of the higher capital costs for baseload plants proportionately more than lower load factor classes.

Q. Is this true for the transmission network?

A. No, it is not. The design of the bulk transmission system network is driven by the need to reliably deliver the required throughput on the transmission system during regional peak demands over a variety of system conditions and likely contingency scenarios. Therefore, it is appropriate to classify most transmission system costs to the demand component. This is supported by the fact that the transmission system's cost allocation approach is dominated by coincident peak approaches such as 12 CP, which was, for some time, a *de facto* standard in Federal Energy Regulatory Commission (FERC) transmission rate cases.

Q. Is the distribution system similar to the transmission system?

A. Yes. Distribution systems are similarly designed to meet maximum demands. However, the distribution system is much more circuit-oriented in its planning compared to the transmission system. Because of this, the maximum burdens on the distribution system typically do not coincide with transmission system peak demands. Distribution planners use NCD for design purposes accordingly. Thus, classification of significant amounts of distribution system costs to the energy component is not appropriate, which is the result when using the Average and Excess method. Schedule SRZ-5 consists of two tables taken from the NARUC Cost Allocation Manual.[4] Table 6-1 is the Classification of Distribution Plant and table 6-2 is the Classification of Distribution Expense. Obvious from these tables is that there is no allocation of distribution service costs to the energy component.

Q. Do you recommend that distribution service costs be classified different than the Average and Excess methodology?

A. Yes. For the reasons outlined in my testimony, I believe that the BPU should move away from the use of the Average and Excess methodology to classify distribution costs. While JCP&L believes classification of distribution costs to just customer and demand components is appropriate, the Company also believes, based on my recommendation, that some transition away from using energy as a factor is necessary based on the rate design principle of gradualism. Therefore, the Company is only proposing two incremental changes at this time. To begin to move away from the Average and Excess method of classifying distribution costs, the Company proposes to classify FERC Account 368: Line Transformers 100% to the demand component. The Company also proposes to use NCD as an alternative allocator and reduce the load factor by one-half when using the Average and Excess methodology in the Proposed COSS. This change moves the Proposed COSS

[4] *See Electric Utility Cost Allocation Manual*, National Association of Regulatory Commissioners, pp. 87-88 (Jan. 1992).

incrementally toward alignment with the NARUC Cost Allocation Manual and generally accepted principles for the classification of distribution system costs as demand related.

Q. Do you also make modifications to the allocation of costs in FERC Account 369 – Services?

A. Yes. The Complied COSS assumes a 50/50 classification between customer and demand components. I believe that modification of the classification of costs in FERC Account 369 is also appropriate.

Q. Please describe what information is being used to classify costs in FERC Account 369.

A. Similar to the Company's methodology used to classify meters, three pieces of information are being used to classify these costs. The first are data on the current moving average price and estimated installation cost for the services that are installed in JCP&L's service territory for secondary service rate classes. The second are data on the costs that are incurred to procure, store, and install services, that are separate from the cost of the conductor itself. The third is updated information on the number of services by service-type that are currently installed in JCP&L's territory as of September 2019 by rate class.

Q. How are these three pieces of data used?

A. The moving average price is used to calculate the minimum and average material (conductor) costs. The costs associated with storing and installing conductor were estimated to capture the fully-loaded costs of procuring and installing the services.

The number of services currently installed in the field, by service-type and rate class, is used to weight the costs of individual parts to develop a minimum and average cost by rate class. These three pieces of data are then used to classify the costs in Account 369 into customer and demand components. The customer component is estimated as the ratio of the minimum service cost to the average service cost by rate class, and the remainder is classified as the demand component.

Q. How were the number and service-types currently installed in JCP&L's service territory by rate class determined for purposes of this study?

A. The Company relied on the meter code for each customer account to determine whether the service was single-phase or three-phase. Further, meter data was also used to determine the service voltage. In cases where the meter code indicated that the meter was variable voltage, the Company relied on data in its customer information system to make these determinations. Next, the Company relied on account-level demand data from its customer information system to estimate the size of each customer's service. The service voltage was also an input to determine service size. For customers with demand meters, the highest billing demand during the 12-month period ending October 2019 was used to determine the size of the service. For customers without demand meters, such as residential customers and small commercial customers, the customer Peak Load Contribution (PLC) as of October 2019 was used to estimate the size of the service.

Q. How many different secondary service sizes are available?

A. There are six (6) service sizes used to serve secondary voltage rate classes, which are listed in the table below:

Cable Type
CABLE OH 600V QX 1/0 AAC 1/0ACSR COSTENA
CABLE OH 600V QX 336.4 AA 336.4AA LIPPIZ
CABLE OH 600V QX 4/0AA 4/0ACSR APPALOOSA
CABLE OH 600V TX #2 AAC #2 AAAC (SHRIMP)
CABLE OH 600V TX 1/0AAC 1/0ACSR NERITINA
CABLE OH 600V TX 4/0 AAC 2/0ACSR CERAPUS

Q. Why is it appropriate to consider the fully-loaded cost of services in the classification of costs in FERC Account 369?

A. For the same reasons it is appropriate to consider the fully-loaded installed cost for meters, it is also appropriate to consider the fully-loaded installed costs for services for the purpose of this study. The total installation cost used in this study is the sum of material costs, labor costs, and supporting equipment costs, including both direct and indirect costs.

Q. What is the next step after calculating the fully-loaded cost of each service?

A. The next step is to use the fully-loaded cost for each service to calculate the weighted average and minimum fully-loaded service cost by rate class. To do this, the number of services by service size that are currently deployed in JCP&L's territory by rate class was determined, as described above. The weighted average fully-loaded cost is calculated using the fully-loaded cost of each service size, and weighting it based on the distribution of each service size within a rate class. The minimum fully-loaded service cost is then identified as the cost of the lowest-cost service size for a specific rate class.

Q. Please explain how you classify costs in FERC Account 369.

A. To classify the costs in Account 369 to the customer and demand components, the minimum size approach was used. As it applies to services, this approach aims to identify the minimum size service for each rate class that is necessary to serve a customer and identifies this as the customer component of the cost of the service. Costs in excess of that minimum size service are classified to the demand component for each rate class.

The lowest fully-loaded service cost was used as the minimum size component and it was compared to the average fully loaded service cost for each rate class. To calculate the breakout between the customer and demand component, the ratio between the cost of the minimum cost for the service and the average cost of the service was calculated for each rate class.

Q. Is this methodology consistent with the BPU order in the 2012 rate case?

A. No. As I have explained, a 50/50 classification between customer and demand was used in that case. However, this methodology is consistent with the methodology ordered by the Board in in the 2012 rate case for Account 370: Meters; but, with modifications to incorporate fully-loaded costs for service installations.

Q. To which classes did you apply this methodology in the present study?

A. This methodology was applied to the secondary service rate classes, which include RS, RT, GS, and GST classes.

Q. Please summarize the results of your classification of costs in Account 369.

A. The results of the analysis are shown in Table 4 below. The section at the top of the table shows the share of costs that would be assigned to the customer component, if only material costs were considered, and thus excluded labor and related overheads. The bottom section shows the customer component calculated using fully-loaded services costs, which include labor, supporting equipment, and related overheads.

Table 4: Customer Component for select Rate Classes Using Fully-Loaded Services Costs

	RS	RT/RGT	GS	GST
Material Only Costs				
Minimum Cost ($)	$50.01	$50.01	$50.01	$194.06
Weighted Average Cost ($)	$50.12	$50.06	$122.89	$287.04
Customer Component (%)	99.8%	99.9%	40.7%	67.6%
Fully Loaded Costs				
Minimum Cost ($)	$578.32	$578.32	$578.32	$940.28
Weighted Average Cost ($)	$578.58	$578.44	$755.12	$1,061.62
Customer Component (%)	100.0%	100.0%	76.6%	88.6%

Q. Please explain the reasons why using fully-loaded installation costs results in a higher customer component when compared to the results of the Board-ordered Complied COSS?

A. The increase in the customer component is driven primarily by two factors. First is that the material cost, generally represents a relatively small share of total installation costs, especially for smaller services. Second is that the share of labor, equipment, and related overhead costs, which represent a larger share of total costs, do not vary significantly across service- types. The result is that the minimum installation cost and average installation cost increase by roughly the same amount when I include the labor, equipment, and overhead costs. Therefore, the minimum cost now represents a larger share of the average cost.

Q. Please summarize the modifications in the Company's Proposed COSS.

A. My testimony provides support for a number of proposed modifications to the Complied COSS. The table below reflects the proposed segmentation of primary and secondary voltage components for FERC Accounts 360-362 and 364-367, a refined computation to estimate the customer component of FERC Account 370, the proposed classification of costs in Account 368, as well as all other FERC Accounts in the Proposed COSS that are classified using the Average and Excess methodology. It also shows the proposed refined computation to estimate the customer component for FERC Account 369 (Services).

Table 5: Proposed Classification and Segmentation of select FERC Accounts

Segmentation of FERC Accounts 360-362, 364-367

FERC Account	Primary	Secondary
360	41.1%	58.9%
361	63.3%	36.7%
362	100.0%	0.0%
364-367	30.5%	69.5%

Classification of FERC Account 368

FERC Account	Demand	Energy
368	100%	0%

Classification of FERC Account 369

Rate Class	Customer	Demand
RS	100.0%	0.0%
RT	100.0%	0.0%
GS	76.5%	23.5%
GST	88.7%	11.3%

Classification of FERC Account 370

Rate Class	Customer	Demand
RS	96.0%	4.0%
RT	67.2%	32.8%
GS	46.5%	53.5%
GST	33.0%	67.0%

Q. What are the Schedules that support the Proposed COSS?

A. Schedules SRZ-2, SRZ-3, and SRZ-4, and SRZ-5.

Q. Please describe Schedule SRZ-2.

A. This schedule contains the summary of the Proposed COSS results. It displays summary level information related to the calculation of each rate class's rate of return at present and proposed revenue levels.

Q. Please describe the Schedule SRZ-3 work papers that support the development of the Proposed COSS.

A. This schedule contains work papers that support the development of the Proposed COSS. The work papers are listed below and are accompanied by a brief explanation of each:

1) WP 12 (NCD) displays the average of the four summer monthly non-coincident peak demands, by rate class.
2) WP 13 (Modified Voltage Specific Factors) displays the calculation of the load factors by voltage levels using non- coincident peaks
3) WP 14 (Modified Primary/Secondary Segmentation [Accounts 364-367]) displays distribution assets in FERC accounts 364-367 by sub-function (two discrete categories, primary facilities and secondary facilities).
4) WP 15 (Modified Minimum Meter Customer Component) displays the modified classification of metering customer between customer and demand related.
5) WP 16 (Average Circuit Data) displays average number of customers per circuit, by circuit type.
6) WP 17 (Primary/Secondary Segmentation [Accounts 580, 589, 590]) shows the allocation calculation of the distribution assets in FERC accounts 580, 589, and 590.
7) WP 18 (Service Cost Allocation) allocates the cost of service costs to rate classes and is based on the Company's methodology.

Q. Please briefly describe Schedule SRZ-4.

A. Schedule SRZ-4 contains certain of the Company's distribution engineering practices. Specifically, these practices describe how the Company's engineers determine the size of a line transformer and what demand factors the Company's engineers look to when planning for load on a distribution transformer in a substation.

VI. <u>Results of Company's Proposed COSS</u>

Q. Please explain the layout of the Company's Proposed COSS (Schedule SRZ-2).

A. Page 1 of Schedule SRZ-2 displays the calculation of revenue requirements reflecting the proposed distribution tariff revenue by customer, demand, and energy classifications.

Page 2, at lines 1-25, of Schedule SRZ-2 summarizes the net operating income and resulting rate of return for each rate class at present tariff charges.

Page 2, at lines 25-31, of Schedule SRZ-2 calculates the amount of distribution revenue change necessary to achieve equal rates of return for each rate class. Each rate class is calculated to earn a rate of return equal to the total Company rate of return sought in this proceeding.

Page 2, at lines 32-38, of Schedule SRZ-2 calculates the amount of distribution revenue change necessary to maintain the unitized rates of return that exist under present tariff rates. A unitized rate of return compares the rate of return for a rate class to the Company's overall system rate of return. If the unitized rate of return for a given rate class is less than 1.0, that rate class's rate of return is lower than the Company's overall rate of return. If a rate class's unitized rate of return is greater than 1.0, the rate class's rate of return exceeds the total Company's rate of return.

If the Company designed rates to maintain these unitized rates of return, the relative returns between rate classes would remain intact.

Page 2, at lines 40-46 of Schedule SRZ-2 shows the rates of return that result from revising the existing distribution charge revenues to the Company's proposed target levels. The testimony of JCP&L witness Yongmei Peng will discuss the movement from the existing unitized rates of return to those currently being proposed on line 46.

Pages 3 - 38 of Schedule SRZ-2 display the detailed allocated and classified costs supporting lines 1-25 of page 2. The method of classification/allocation is displayed for each account in the study also.

Pages 39-48 of Schedule SRZ-2 display the input tabs used in the model.

Q. Please explain the derivation of the proposed revenue requirements on page 1 of Schedule SRZ-2.

A. The first step in the development of revenue requirements is the calculation of requested rates of return for each rate class as shown on line 46 of page 2 of Schedule SRZ-2. Lines 40-46 of this page calculates the net operating income and rate of return resulting from the changes in distribution revenue proposed for each rate class by Ms. Peng. Line 43 displays the changes in distribution revenue she is proposing, which, when tax-effected and added to the current net operating income on line 19, yields the requested net operating income on line 44. (Current Operating Income + (Revenue Change x 1 – Composite Tax Rate of 28.11%)). This amount, when divided by the rate base, yields the rates of return being requested for each rate class on line 45. Subsequent proposed unitized rates of return are shown on line 46.

Customer, demand, and energy revenue requirements sufficient to earn the requested rate of return are calculated on page 1 of the COSS. I will explain the calculation of the demand-related revenue requirements as an example. Customer and energy-related requirements are calculated in a similar manner. The demand-related rate base for each rate class is shown on line 17. The rate base multiplied by the after-tax rate of return requested for each rate class, from page 2, is equal to the after tax return on rate base, or in other words, net operating income on rate base (income after tax, or "IAT"),shown on line 19. The Net Income was then determined on line 21 by backing the Interest Expense out of the Net Operating Income. The Federal and State Income Taxes were calculated via the following formulas: Federal Income Tax = <u>Net Income * (1/(1-.21)-1)</u> <u>State Income Tax= (Net Income + Federal Income Tax) * (1/(1-.09)-1)</u>. Finally, an algebraic formula was derived to "gross up" to a rate base ("RB") revenue requirement, shown on line 26. The formula is as follows:

RB Rev. Req. = <u>Interest Expense + Net Income + Federal Income Taxes + State Income Taxes + (Investment Tax Credit +Federal Tax Reform)*(1/(1-.2811)).</u>

The total distribution revenue requirement on line 28 is calculated by adding the rate base revenue requirement to the expenses on line 27. These are the total revenues the Company must receive to achieve the requested rate of return. Other operating revenues, line 29, are deducted to derive distribution tariff revenue (line 30).

Q. Please summarize the results of the Proposed COSS.

A. The Company's total present net operating income of $67.28 million represents a 2.59% return on rate base of $2.6 billion. Following the $186.95 million increase in distribution revenues being sought in this proceeding, the resulting rate of return will be 7.76%.

Table 6 below summarizes the rates of return and unitized rates of return prior to the proposed rate changes. Rate classes RS, GST, and LTG are presently earning less than the overall distribution rate of return, while Rate classes, RT, GS, GP and GT are earning higher rates of return than the overall distribution rate of return.

Table 6: Proposed COSS Summary at Present Revenues

Rate	Rate of Return	Unitized
RS	1.68%	0.65
RT	3.21%	1.24
GS	3.40%	1.31
GST	2.36%	0.91
GP	6.78%	2.62
GT	25.86%	9.99
LTG	1.51%	0.58
Total	**2.59%**	**1.00**

Table 7 below summarizes the rates of return and unitized rates of return at the proposed revenue changes.

Table 7: Proposed COSS Summary at Proposed Revenues

Rate	Rate of Return	Unitized
RS	6.74%	0.87
RT	8.76%	1.13
GS	8.62%	1.11
GST	7.73%	1.00
GP	15.97%	2.06
GT	45.28%	5.84
LTG	3.19%	0.41
Total	**7.76%**	**1.00**

Q. Does this conclude your direct testimony?

A. Yes, at this time.

Appendix A

PROFESSIONAL AND EDUCATIONAL BACKGROUND

OF

STEPHANIE ZIEGER

Stephanie Zieger graduated from West Chester University in 2016 with a Master of Science in Applied Statistics. Prior to that, she obtained Bachelor of Science degrees in both Mathematics and Economics from Elizabethtown College.

Ms. Zieger joined FirstEnergy Corp. ("FirstEnergy") in December 2015 as an Analyst in the Rates & Regulatory Affairs Department. She assisted in the rate design and preparation of FirstEnergy's Pennsylvania operating Companies 2016 Base Rate Cases. She is also responsible for supporting and preparing other state and federal regulatory filings, assisting with monthly regulatory accounting closing, updating rate calculations and calculating financial analyses on both budgeted and actual data. From 2017-2018, Ms. Zieger assisted with the Forecasting group where she was involved in preparing and supporting various monthly variance analysis reports for all of FirstEnergy's distribution utility subsidiaries and ad-hoc retail revenue forecasting. In performing her work, she interacts with various groups within FirstEnergy that are responsible for business planning and reporting. Ms. Zieger has also attended seminars and conferences dealing with the utility industry, ratemaking, and cost of service work.

Prior to working at FirstEnergy, Ms. Zieger was employed by Exelon Nuclear as a Corporate Performance Improvement Intern. In this role, she served as project coordinator on a data analysis project by organizing and consolidating data for analysis.

Prior to working at Exelon Nuclear, Ms. Zieger was employed in the insurance industry at AmWINS Program Underwriters as an Assistant Program Underwriter. In this role, she was responsible for maintaining an individual book of business, providing quotations, binding and issuing policies for both new and renewal business accounts.

Jersey Central Power & Light
Present Distribution Rate of Return
Test Year: July 2019 - June 2020
Complied COSS

Line	Description	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
1	Distribution Revenues	$542,868,768	$283,576,706	$6,369,034	$179,570,595	$11,123,447	$25,384,277	[redacted]	[redacted]	$17,833,311
2	Other Operating Revenues	$15,275,018	$9,443,971	$176,735	$4,420,048	$256,381	$408,885	[redacted]	[redacted]	$700,984
3	**Total Operating Revenues**	**$558,143,786**	**$293,020,676**	**$6,545,769**	**$183,990,642**	**$11,379,828**	**$25,793,163**	[redacted]	[redacted]	**$18,534,295**
4								[redacted]	[redacted]	
5	Total O&M Expenses	$227,372,423	$133,107,032	$2,757,355	$66,897,747	$4,817,081	$12,493,267	[redacted]	[redacted]	$4,403,300
6	Total Depreciation Expense	$145,645,195	$83,005,261	$1,636,854	$41,975,181	$3,067,212	$4,336,316	[redacted]	[redacted]	$10,081,590
7	Total Amortization Expense [1]	$113,511,669	$60,335,152	$1,145,652	$33,586,336	$2,559,749	$7,386,375	[redacted]	[redacted]	$640,529
8	Total Taxes Other Than Income	$9,902,467	$5,767,869	$114,744	$2,926,939	$213,601	$423,440	[redacted]	[redacted]	$350,154
9	**Total Expenses**	**$496,431,754**	**$282,215,313**	**$5,654,605**	**$145,386,205**	**$10,657,643**	**$24,639,398**	[redacted]	[redacted]	**$15,475,573**
10								[redacted]	[redacted]	
11	**Income Before Taxes**	**$61,712,032**	**$10,805,363**	**$891,164**	**$38,604,438**	**$722,185**	**$1,153,765**	[redacted]	[redacted]	**$3,058,722**
12								[redacted]	[redacted]	
13	State Income Taxes	($57,665)	($2,262,970)	$17,775	$1,776,371	($61,415)	($72,615)	[redacted]	[redacted]	$15,146
14	Federal Income Taxes	($122,442)	($4,805,041)	$37,741	$3,771,828	($130,405)	($154,186)	[redacted]	[redacted]	$32,160
15	Investment Tax Credit	($97,625)	($56,286)	($1,086)	($29,540)	($2,199)	($3,070)	[redacted]	[redacted]	($4,526)
16	Federal Tax Reform	($5,291,287)	($3,050,691)	($58,865)	($1,601,062)	($119,193)	($166,377)	[redacted]	[redacted]	($245,284)
17	**Total Income Taxes**	**($5,569,019)**	**($10,174,988)**	**($4,435)**	**$3,917,598**	**($313,212)**	**($396,248)**	[redacted]	[redacted]	**($202,503)**
18								[redacted]	[redacted]	
19	**Net Operating Income**	**$67,281,051**	**$20,980,350**	**$895,599**	**$34,686,840**	**$1,035,397**	**$1,550,013**	[redacted]	[redacted]	**$3,261,225**
20								[redacted]	[redacted]	
21	**Rate Base**	**$2,598,923,793**	**$1,498,409,408**	**$28,912,798**	**$786,394,177**	**$58,544,078**	**$81,719,689**	[redacted]	[redacted]	**$120,476,069**
22								[redacted]	[redacted]	
23	Rate of Return	2.59%	1.40%	3.10%	4.41%	1.77%	1.90%	[redacted]	[redacted]	2.71%
24								[redacted]	[redacted]	
25	**Existing Unitized Rate of Return**		**0.54**	**1.20**	**1.70**	**0.68**	**0.73**	[redacted]	[redacted]	**1.05**

Jersey Central Power & Light
Complied COSS Revenues
Test Year: July 2019 - June 2020
Complied COSS

Line	Description	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
1	Distribution Revenues	$542,868,768	$283,576,706	$6,369,034	$179,570,595	$11,123,447	$25,384,277	[redacted]	[redacted]	$17,833,311
2	Other Operating Revenues	$15,275,018	$9,443,971	$176,735	$4,420,048	$256,381	$408,885	[redacted]	[redacted]	$700,984
3	**Total Operating Revenues**	**$558,143,786**	**$293,020,676**	**$6,545,769**	**$183,990,642**	**$11,379,828**	**$25,793,163**	[redacted]	[redacted]	**$18,534,295**

Jersey Central Power & Light
Other Operating Revenues
Test Year: July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
REV	Rev - Retail Distribution	Total			$542,868,768	$283,576,706	$6,369,034	$179,570,595	$11,123,447	$25,384,277	[redacted]	[redacted]	$17,833,311
		Customer	DIST-REV-CUST	DIST-REV-CUST	$41,918,982	$30,980,844	$886,940	$9,291,578	$94,289	$250,047	[redacted]	[redacted]	$0
		Demand	DIST-REV-DMD	DIST-REV-DMD	$150,980,629	$0	$0	$95,229,974	$8,719,365	$19,685,757	[redacted]	[redacted]	$12,839,173
		Energy	DIST-REV-NRG	DIST-REV-NRG	$349,969,157	$252,595,861	$5,482,095	$75,049,042	$2,309,794	$5,448,473	[redacted]	[redacted]	$4,994,139
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
450	Rev - Elec Frft Discount	Total			$2,247,882	$347	$0	$1,833,683	$65,385	$234,858	[redacted]	[redacted]	$293,510
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DMD	LATEPAY	$2,247,882	$347	$0	$1,833,683	$65,385	$234,858	[redacted]	[redacted]	$293,510
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
451	Rev - Misc Service	Total			$5,157,789	$4,256,421	$40,846	$687,062	$54,613	$15,742	[redacted]	[redacted]	$62,234
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DMD	ALL451	$5,157,789	$4,256,421	$40,846	$687,062	$54,613	$15,742	[redacted]	[redacted]	$62,234
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
454	Rev - Rent from Elec Prpty	Total			$6,481,819	$3,793,953	$71,790	$1,927,722	$142,381	$173,051	[redacted]	[redacted]	$355,107
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$488,146	$399,317	$6,111	$50,746	$176	$13,982	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$3,558,162	$2,112,047	$35,767	$936,559	$67,403	$67,545	[redacted]	[redacted]	$338,841
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$2,435,511	$1,282,589	$29,912	$940,417	$74,803	$91,525	[redacted]	[redacted]	$16,266
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
456PG	Other Elec Revs - Pwr Guard	Total			$1,655,608	$1,517,831	$67,438	$70,339	$0	$0	[redacted]	[redacted]	$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DMD	PWRGD	$1,655,608	$1,517,831	$67,438	$70,339	$0	$0	[redacted]	[redacted]	$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
REV-DIST	Distribution Revenues	Total			$542,868,768	$283,576,706	$6,369,034	$179,570,595	$11,123,447	$25,384,277	[redacted]	[redacted]	$17,833,311
		Customer			$41,918,982	$30,980,844	$886,940	$9,291,578	$94,289	$250,047	[redacted]	[redacted]	$0
		Demand			$150,980,629	$0	$0	$95,229,974	$8,719,365	$19,685,757	[redacted]	[redacted]	$12,839,173
		Energy			$349,969,157	$252,595,861	$5,482,095	$75,049,042	$2,309,794	$5,448,473	[redacted]	[redacted]	$4,994,139
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
450,451,456	Other Operating Revs	Total			$15,543,099	$9,568,552	$180,074	$4,518,806	$262,379	$423,651	[redacted]	[redacted]	$710,851
		Customer			$488,146	$399,317	$6,111	$50,746	$176	$13,982	[redacted]	[redacted]	$0
		Demand			$12,619,441	$7,886,646	$144,051	$3,527,643	$187,401	$318,145	[redacted]	[redacted]	$694,585
		Energy			$2,435,511	$1,282,589	$29,912	$940,417	$74,803	$91,525	[redacted]	[redacted]	$16,266
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-REV	Adjs to Revenue	Total			($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)	[redacted]	[redacted]	($9,867)
		Customer			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand			($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)	[redacted]	[redacted]	($9,867)
		Energy			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-TOTREV	Total Adj Revenues	Total			$558,143,786	$293,020,676	$6,545,769	$183,990,642	$11,379,828	$25,793,163	[redacted]	[redacted]	$18,534,295
		Customer			$42,407,129	$31,380,161	$893,051	$9,342,324	$94,464	$264,029	[redacted]	[redacted]	$0
		Demand			$163,331,988	$7,762,064	$140,711	$98,658,859	$8,900,767	$19,989,136	[redacted]	[redacted]	$13,523,891
		Energy			$352,404,669	$253,878,451	$5,512,007	$75,989,460	$2,384,596	$5,539,998	[redacted]	[redacted]	$5,010,405

Jersey Central Power & Light
Total Operation & Maintenance Expenses
Test Year July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
524	Misc Nuclear Pwr Exp	Total			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
580P	OP Supv & Eng - PRI	Total			$32,754	$18,688	$353	$10,417	$795	$2,402	[redacted]	[redacted]	$98
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$17,430	$11,059	$175	$4,824	$350	$1,020	[redacted]	[redacted]	$2
		Energy	AE-PRI-NRG	NRG-PRI	$15,324	$7,629	$178	$5,594	$445	$1,382	[redacted]	[redacted]	$97
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
580S	OP Supv & Eng - SEC	Total			$56,525	$34,855	$657	$19,357	$1,476	$0	[redacted]	[redacted]	$181
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$30,969	$20,871	$331	$9,103	$661	$0	[redacted]	[redacted]	$3
		Energy	AE-SEC-NRG	NRG-SEC	$25,556	$13,984	$326	$10,253	$816	$0	[redacted]	[redacted]	$177
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
581	Load Dispatching	Total			$1,283,749	$732,450	$13,843	$408,295	$31,162	$94,140	[redacted]	[redacted]	$3,859
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$683,139	$433,444	$6,870	$189,059	$13,724	$39,974	[redacted]	[redacted]	$67
		Energy	AE-PRI-NRG	NRG-PRI	$600,611	$299,005	$6,973	$219,236	$17,438	$54,166	[redacted]	[redacted]	$3,792
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
582P	Station Exp	Total			$293,317	$167,354	$3,163	$93,289	$7,120	$21,510	[redacted]	[redacted]	$882
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$156,087	$99,035	$1,570	$43,197	$3,136	$9,133	[redacted]	[redacted]	$15
		Energy	AE-PRI-NRG	NRG-PRI	$137,230	$68,318	$1,593	$50,092	$3,984	$12,376	[redacted]	[redacted]	$866
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
582S	Station Exp	Total			$293,317	$180,866	$3,409	$100,444	$7,661	$0	[redacted]	[redacted]	$937
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$160,703	$108,302	$1,716	$47,239	$3,429	$0	[redacted]	[redacted]	$17
		Energy	AE-SEC-NRG	NRG-SEC	$132,614	$72,564	$1,692	$53,205	$4,232	$0	[redacted]	[redacted]	$920
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
583P	OH Line Exp	Total			$693,425	$395,637	$7,477	$220,543	$16,832	$50,850	[redacted]	[redacted]	$2,085
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$369,002	$234,128	$3,711	$102,122	$7,413	$21,592	[redacted]	[redacted]	$36
		Energy	AE-PRI-NRG	NRG-PRI	$324,424	$161,510	$3,767	$118,422	$9,419	$29,258	[redacted]	[redacted]	$2,048
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
583S	OH Line Exp	Total			$693,425	$427,582	$8,059	$237,458	$18,111	$0	[redacted]	[redacted]	$2,215
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$379,914	$256,034	$4,058	$111,677	$8,106	$0	[redacted]	[redacted]	$40
		Energy	AE-SEC-NRG	NRG-SEC	$313,511	$171,548	$4,001	$125,782	$10,005	$0	[redacted]	[redacted]	$2,176
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
584P	UG Line Exp	Total			$1,685,116	$961,452	$18,171	$535,950	$40,905	$123,573	[redacted]	[redacted]	$5,066
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$896,724	$568,962	$9,017	$248,169	$18,014	$52,472	[redacted]	[redacted]	$88
		Energy	AE-PRI-NRG	NRG-PRI	$788,393	$392,490	$9,153	$287,781	$22,891	$71,101	[redacted]	[redacted]	$4,978
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
584S	UG Line Exp	Total			$1,685,116	$1,039,080	$19,583	$577,056	$44,013	$0	[redacted]	[redacted]	$5,384
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$923,243	$622,196	$9,861	$271,389	$19,700	$0	[redacted]	[redacted]	$97
		Energy	AE-SEC-NRG	NRG-SEC	$761,873	$416,884	$9,722	$305,667	$24,313	$0	[redacted]	[redacted]	$5,287

REDACTED

Jersey Central Power & Light
Total Operation & Maintenance Expenses
Test Year July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
585	St Lt & Signal Sys Exp	Total			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
586	Meter Exp	Total			$1,124,469	$746,601	$22,487	$194,651	$5,794	$68,128	[redacted]		$0
		Customer	MTR-CUST	CUST-MTR	$913,953	$664,331	$10,008	$84,078	$600	$68,128	[redacted]		$0
		Demand	MTR-DMD	DMD-MTR	$210,516	$82,269	$12,479	$110,574	$5,194	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
588	Misc Exp	Total			$17,308,525	$9,803,029	$189,667	$5,420,331	$410,660	$459,361	[redacted]		$1,025,477
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DIST-CLA-DMD	DIST-PLT-DMD	$10,275,256	$6,099,168	$103,288	$2,704,595	$194,645	$195,057	[redacted]		$978,504
		Energy	DIST-CLA-NRG	DIST-PLT-NRG	$7,033,268	$3,703,861	$86,379	$2,715,736	$216,015	$264,304	[redacted]		$46,973
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
589P	Rent-PRI	Total			$2,266,262	$1,293,027	$24,437	$720,783	$55,012	$166,189	[redacted]		$6,813
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$1,205,976	$765,180	$12,127	$333,755	$24,227	$70,568	[redacted]		$119
		Energy	AE-PRI-NRG	NRG-PRI	$1,060,285	$527,848	$12,310	$387,027	$30,785	$95,621	[redacted]		$6,694
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
589S	Rent-SEC	Total			$3,911,020	$2,411,622	$45,452	$1,339,300	$102,151	$0	[redacted]		$12,495
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$2,142,773	$1,444,067	$22,887	$629,872	$45,722	$0	[redacted]		$224
		Energy	AE-SEC-NRG	NRG-SEC	$1,768,247	$967,555	$22,565	$709,428	$56,429	$0	[redacted]		$12,271
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
590P	Maint Supv & Engr - PRI	Total			$593,407	$338,571	$6,399	$188,733	$14,405	$43,516	[redacted]		$1,784
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$315,778	$200,358	$3,175	$87,392	$6,344	$18,478	[redacted]		$31
		Energy	AE-PRI-NRG	NRG-PRI	$277,629	$138,214	$3,223	$101,341	$8,061	$25,038	[redacted]		$1,753
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
590S	Maint Supv & Engr - SEC	Total			$1,024,077	$631,469	$11,901	$350,688	$26,748	$0	[redacted]		$3,272
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$561,072	$378,120	$5,993	$164,928	$11,972	$0	[redacted]		$59
		Energy	AE-SEC-NRG	NRG-SEC	$463,005	$253,348	$5,908	$185,759	$14,776	$0	[redacted]		$3,213
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
591	Maint of Structures	Total			$119,074	$67,938	$1,284	$37,871	$2,890	$8,732	[redacted]		$358
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$63,364	$40,204	$637	$17,536	$1,273	$3,708	[redacted]		$6
		Energy	AE-PRI-NRG	NRG-PRI	$55,709	$27,734	$647	$20,335	$1,617	$5,024	[redacted]		$352
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
592P	Maint of Station Equip - PRI	Total			$5,327,148	$3,039,432	$57,443	$1,694,295	$129,313	$390,650	[redacted]		$16,015
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$2,834,807	$1,798,656	$28,507	$784,536	$56,949	$165,880	[redacted]		$280
		Energy	AE-PRI-NRG	NRG-PRI	$2,492,341	$1,240,776	$28,937	$909,759	$72,364	$224,770	[redacted]		$15,736
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
592S	Maint of Station Equip - SEC	Total			$5,327,148	$3,284,838	$61,909	$1,824,243	$139,139	$0	[redacted]		$17,019
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$2,918,642	$1,966,945	$31,174	$857,941	$62,277	$0	[redacted]		$306
		Energy	AE-SEC-NRG	NRG-SEC	$2,408,506	$1,317,893	$30,735	$966,303	$76,862	$0	[redacted]		$16,714

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
593P	Maint of OH Lines - PRI	Total			$18,347,900	$10,468,488	$197,848	$5,835,535	$445,382	$1,345,487	[redacted]		$55,160
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$9,763,715	$6,194,976	$98,183	$2,702,120	$196,144	$571,329	[redacted]		$963
		Energy	AE-PRI-NRG	NRG-PRI	$8,584,185	$4,273,512	$99,664	$3,133,415	$249,238	$774,159	[redacted]		$54,197
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
593S	Maint of OH Lines - SEC	Total			$18,347,900	$11,313,723	$213,228	$6,283,105	$479,225	$0	[redacted]		$58,618
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$10,052,461	$6,774,602	$107,370	$2,954,941	$214,496	$0	[redacted]		$1,053
		Energy	AE-SEC-NRG	NRG-SEC	$8,295,438	$4,539,121	$105,859	$3,328,164	$264,729	$0	[redacted]		$57,565
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
594P	Maint of UG Lines - PRI	Total			$1,798,515	$1,026,152	$19,394	$572,016	$43,658	$131,889	[redacted]		$5,407
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$957,068	$607,250	$9,624	$264,870	$19,227	$56,003	[redacted]		$94
		Energy	AE-PRI-NRG	NRG-PRI	$841,447	$418,902	$9,769	$307,146	$24,431	$75,885	[redacted]		$5,313
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
594S	Maint of UG Lines - SEC	Total			$1,798,515	$1,109,004	$20,901	$615,888	$46,975	$0	[redacted]		$5,746
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$985,372	$664,066	$10,525	$289,652	$21,026	$0	[redacted]		$103
		Energy	AE-SEC-NRG	NRG-SEC	$813,143	$444,938	$10,377	$326,236	$25,949	$0	[redacted]		$5,643
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
595	Maint of Line Trnsfrmrs	Total			$350,274	$236,059	$3,741	$102,964	$7,474	$0	[redacted]		$37
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DMD	DMD-SEC	$350,274	$236,059	$3,741	$102,964	$7,474	$0	[redacted]		$37
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
596	Maint of St Lt & Signal Sys	Total			$3,006,789	$0	$0	$0	$0	$0	[redacted]		$3,006,789
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DMD	DMD-LTG	$3,006,789	$0	$0	$0	$0	$0	[redacted]		$3,006,789
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
597	Maint of Meters	Total			$4,870,664	$3,233,920	$97,402	$843,136	$25,096	$295,098	[redacted]		$0
		Customer	MTR-CUST	CUST-MTR	$3,958,810	$2,877,568	$43,348	$364,184	$2,600	$295,098	[redacted]		$0
		Demand	MTR-DMD	DMD-MTR	$911,854	$356,352	$54,054	$478,952	$22,496	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
598	Maint of Misc Dist Plant	Total			$1,578,429	$893,975	$17,296	$494,300	$37,450	$41,891	[redacted]		$93,517
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DIST-CLA-DMD	DIST-PLT-DMD	$937,039	$556,206	$9,419	$246,642	$17,750	$17,788	[redacted]		$89,233
		Energy	DIST-CLA-NRG	DIST-PLT-NRG	$641,390	$337,769	$7,877	$247,658	$19,699	$24,103	[redacted]		$4,284
Subtotal	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
Prod O&M	Production O&M Expense	Total			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Customer			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Energy			$0	$0	$0	$0	$0	$0	[redacted]		$0
Subtotal	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
Dist O&M	Distribution O&M Expense	Total			$93,816,859	$53,855,810	$1,065,504	$28,720,651	$2,139,446	$3,243,415	[redacted]		$4,329,213
		Customer			$4,872,763	$3,541,900	$53,356	$448,261	$3,200	$363,226	[redacted]		$0
		Demand			$51,109,965	$30,518,507	$550,491	$13,758,050	$981,748	$1,223,003	[redacted]		$4,078,167
		Energy			$37,834,131	$19,795,403	$461,657	$14,514,340	$1,154,498	$1,657,186	[redacted]		$251,046
Subtotal	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
TOTD&PO&M	Total Distribution O&M	Total			$93,816,859	$53,855,810	$1,065,504	$28,720,651	$2,139,446	$3,243,415	[redacted]		$4,329,213
		Customer			$4,872,763	$3,541,900	$53,356	$448,261	$3,200	$363,226	[redacted]		$0
		Demand			$51,109,965	$30,518,507	$550,491	$13,758,050	$981,748	$1,223,003	[redacted]		$4,078,167
		Energy			$37,834,131	$19,795,403	$461,657	$14,514,340	$1,154,498	$1,657,186	[redacted]		$251,046

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
901	Supervision	Total			$38,021	$30,166	$605	$6,953	$94	$57	[redacted]	[redacted]	$99
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NRG	ALL901	$38,021	$30,166	$605	$6,953	$94	$57	[redacted]	[redacted]	$99
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
902	Meter Reading Exp	Total			$14,235,371	$9,451,698	$284,675	$2,464,214	$73,347	$862,477	[redacted]	[redacted]	$0
		Customer	MTR-CUST	CUST-MTR	$11,570,317	$8,410,197	$126,693	$1,064,391	$7,599	$862,477	[redacted]	[redacted]	$0
		Demand	MTR-DMD	DMD-MTR	$2,665,054	$1,041,501	$157,982	$1,399,823	$65,748	$0	[redacted]	[redacted]	$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
903	Cust Records & Collect Exp	Total			$14,453,393	$9,596,456	$289,035	$2,501,955	$74,471	$875,686	[redacted]	[redacted]	$0
		Customer	MTR-CUST	CUST-MTR	$11,747,522	$8,539,004	$128,633	$1,080,693	$7,715	$875,686	[redacted]	[redacted]	$0
		Demand	MTR-DMD	DMD-MTR	$2,705,870	$1,057,452	$160,401	$1,421,262	$66,755	$0	[redacted]	[redacted]	$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
904	Cust Uncollect Exp	Total			$119,609	$53,881	$1,257	$39,507	$3,142	$9,761	[redacted]	[redacted]	$683
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NRG	NRG-All	$119,609	$53,881	$1,257	$39,507	$3,142	$9,761	[redacted]	[redacted]	$683
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
905	Misc Cust Acct Exp	Total			$1,436,938	$1,140,084	$22,867	$262,797	$3,558	$2,142	[redacted]	[redacted]	$3,757
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NRG	ALL905	$1,436,938	$1,140,084	$22,867	$262,797	$3,558	$2,142	[redacted]	[redacted]	$3,757
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
907	Supervision	Total			$368,340	$210,158	$3,972	$117,150	$8,941	$27,011	[redacted]	[redacted]	$1,107
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$196,010	$124,366	$1,971	$54,246	$3,938	$11,470	[redacted]	[redacted]	$19
		Energy	AE-PRI-NRG	NRG-PRI	$172,330	$85,792	$2,001	$62,904	$5,004	$15,541	[redacted]	[redacted]	$1,088
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
908	Cust Assist Exp	Total			$1,214,314	$692,833	$13,094	$386,212	$29,477	$89,048	[redacted]	[redacted]	$3,651
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$646,189	$410,000	$6,498	$178,834	$12,981	$37,812	[redacted]	[redacted]	$64
		Energy	AE-PRI-NRG	NRG-PRI	$568,125	$282,833	$6,596	$207,378	$16,495	$51,236	[redacted]	[redacted]	$3,587
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
909	Info & Instrctnl Advertising	Total			$2,400	$1,369	$26	$763	$58	$176	[redacted]	[redacted]	$7
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$1,277	$810	$13	$353	$26	$75	[redacted]	[redacted]	$0
		Energy	AE-PRI-NRG	NRG-PRI	$1,123	$559	$13	$410	$33	$101	[redacted]	[redacted]	$7
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
910	Misc Cust Srvc & Info Exp	Total			$9,383,308	$5,353,695	$101,181	$2,984,354	$227,773	$688,096	[redacted]	[redacted]	$28,209
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$4,993,266	$3,168,176	$50,212	$1,381,892	$100,310	$292,183	[redacted]	[redacted]	$492
		Energy	AE-PRI-NRG	NRG-PRI	$4,390,042	$2,185,519	$50,969	$1,602,461	$127,463	$395,913	[redacted]	[redacted]	$27,717
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
911	Sales Exp	Total			$56,383	$32,170	$608	$17,933	$1,369	$4,135	[redacted]	[redacted]	$170
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$30,004	$19,037	$302	$8,304	$603	$1,756	[redacted]	[redacted]	$3
		Energy	AE-PRI-NRG	NRG-PRI	$26,379	$13,133	$306	$9,629	$766	$2,379	[redacted]	[redacted]	$167

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
920	A&G Salaries	Total			$850,366	$483,847	$9,144	$269,715	$20,585	$62,188	[redacted]		$2,549
		Customer	A&G-GT-CUST	CUST-GTA&G	$2,337	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$451,273	$286,328	$4,538	$124,890	$9,066	$26,406	[redacted]		$45
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$396,756	$197,519	$4,606	$144,825	$11,520	$35,781	[redacted]		$2,505
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
921	Office Supplies & Exp	Total			$1,085,146	$617,434	$11,669	$344,181	$26,269	$79,357	[redacted]		$3,253
		Customer	A&G-GT-CUST	CUST-GTA&G	$2,983	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$575,866	$365,381	$5,791	$159,372	$11,569	$33,697	[redacted]		$57
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$506,297	$252,053	$5,878	$184,810	$14,700	$45,660	[redacted]		$3,197
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
922	Admin Exp Trnsfr Credit	Total			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
923	Outside Services	Total			$32,961,974	$18,754,933	$354,456	$10,454,716	$797,929	$2,410,522	[redacted]		$98,822
		Customer	A&G-GT-CUST	CUST-GTA&G	$90,595	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$17,492,289	$11,098,676	$175,901	$4,841,012	$351,404	$1,023,570	[redacted]		$1,725
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$15,379,090	$7,656,257	$178,555	$5,613,704	$446,525	$1,386,952	[redacted]		$97,097
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
924	Property Insurance	Total			$253,345	$144,150	$2,724	$80,355	$6,133	$18,527	[redacted]		$760
		Customer	A&G-GT-CUST	CUST-GTA&G	$696	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$134,445	$85,304	$1,352	$37,208	$2,701	$7,867	[redacted]		$13
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$118,203	$58,846	$1,372	$43,147	$3,432	$10,660	[redacted]		$746
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
925	Injuries & Damages	Total			$3,344,187	$1,902,799	$35,962	$1,060,693	$80,955	$244,562	[redacted]		$10,026
		Customer	A&G-GT-CUST	CUST-GTA&G	$9,191	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$1,774,696	$1,126,026	$17,846	$491,149	$35,652	$103,847	[redacted]		$175
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$1,560,300	$776,773	$18,115	$569,543	$45,303	$140,714	[redacted]		$9,851
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
926	Pensions & Benefits	Total			$44,294,361	$25,202,914	$476,319	$14,049,066	$1,072,258	$3,239,264	[redacted]		$132,797
		Customer	A&G-GT-CUST	CUST-GTA&G	$121,742	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$23,506,170	$14,914,421	$236,376	$6,505,361	$472,218	$1,375,475	[redacted]		$2,318
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$20,666,449	$10,288,493	$239,942	$7,543,705	$600,041	$1,863,789	[redacted]		$130,479
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
928	Regulatory Comms Exp	Total			$4,483,645	$2,551,136	$48,215	$1,422,100	$108,538	$327,891	[redacted]		$13,442
		Customer	A&G-GT-CUST	CUST-GTA&G	$12,323	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$2,379,385	$1,509,695	$23,927	$658,498	$47,800	$139,231	[redacted]		$235
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$2,091,937	$1,041,441	$24,288	$763,603	$60,738	$188,660	[redacted]		$13,208

REDACTED

Jersey Central Power & Light
Total Operation & Maintenance Expenses
Test Year July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
930.1	Gen Advertising Exp	Total			$996,585	$567,044	$10,717	$316,092	$24,125	$72,881	[redacted]	[redacted]	$2,988
		Customer	A&G-GT-CUST	CUST-GTA&G	$2,739	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$528,869	$335,562	$5,318	$146,365	$10,624	$30,947	[redacted]	[redacted]	$52
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$464,977	$231,482	$5,398	$169,727	$13,500	$41,934	[redacted]	[redacted]	$2,936
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
930.2	Misc Gen Exp	Total			$2,279,321	$1,296,904	$24,511	$722,944	$55,177	$166,688	[redacted]	[redacted]	$6,834
		Customer	A&G-GT-CUST	CUST-GTA&G	$6,265	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$1,209,592	$767,474	$12,164	$334,756	$24,300	$70,780	[redacted]	[redacted]	$119
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$1,063,464	$529,430	$12,347	$388,188	$30,877	$95,908	[redacted]	[redacted]	$6,714
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
931	Rents	Total			$2,510,095	$1,428,211	$26,992	$796,140	$60,763	$183,564	[redacted]	[redacted]	$7,525
		Customer	A&G-GT-CUST	CUST-GTA&G	$6,899	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$1,332,059	$845,178	$13,395	$368,649	$26,760	$77,946	[redacted]	[redacted]	$131
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$1,171,137	$583,033	$13,597	$427,490	$34,003	$105,618	[redacted]	[redacted]	$7,394
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
935	Maint of Gen Plant	Total			$2,562,438	$1,457,994	$27,555	$812,741	$62,030	$187,392	[redacted]	[redacted]	$7,682
		Customer	A&G-GT-CUST	CUST-GTA&G	$7,043	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$1,359,837	$862,802	$13,674	$376,336	$27,318	$79,572	[redacted]	[redacted]	$134
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$1,195,558	$595,191	$13,881	$436,405	$34,712	$107,821	[redacted]	[redacted]	$7,548
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
CA-EXP	Customer Accts Exp	Total			$30,283,331	$20,272,286	$598,439	$5,275,426	$154,613	$1,750,122	[redacted]	[redacted]	$4,540
		Customer			$23,317,839	$16,949,201	$255,327	$2,145,085	$15,314	$1,738,162	[redacted]	[redacted]	$0
		Demand			$5,370,924	$2,098,953	$318,383	$2,821,084	$132,504	$0	[redacted]	[redacted]	$0
		Energy			$1,594,568	$1,224,131	$24,729	$309,257	$6,795	$11,960	[redacted]	[redacted]	$4,540
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
CS&I-EXP	Cust Service & Info Exp	Total			$10,968,363	$6,258,055	$118,273	$3,488,479	$266,249	$804,331	[redacted]	[redacted]	$32,974
		Customer			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand			$5,836,742	$3,703,353	$58,694	$1,615,326	$117,255	$341,540	[redacted]	[redacted]	$576
		Energy			$5,131,620	$2,554,703	$59,579	$1,873,153	$148,994	$462,791	[redacted]	[redacted]	$32,399
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
SALES-EXP	Sales Exp	Total			$56,383	$32,170	$608	$17,933	$1,369	$4,135	[redacted]	[redacted]	$170
		Customer			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand			$30,004	$19,037	$302	$8,304	$603	$1,756	[redacted]	[redacted]	$3
		Energy			$26,379	$13,133	$306	$9,629	$766	$2,379	[redacted]	[redacted]	$167
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
A&G-EXP	A&G Exp	Total			$95,621,463	$54,407,366	$1,028,264	$30,328,743	$2,314,762	$6,992,836	[redacted]	[redacted]	$286,679
		Customer			$262,814	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand			$50,744,481	$32,196,847	$510,282	$14,043,597	$1,019,411	$2,969,339	[redacted]	[redacted]	$5,004
		Energy			$44,614,168	$22,210,518	$517,981	$16,285,146	$1,295,351	$4,023,497	[redacted]	[redacted]	$281,675
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTCSA&G	Total Cust Srvc and A&G Exp	Total			$136,929,540	$80,969,877	$1,745,583	$39,110,580	$2,736,993	$9,551,424	[redacted]	[redacted]	$324,363
		Customer			$23,580,653	$16,949,201	$255,327	$2,145,085	$15,314	$1,738,162	[redacted]	[redacted]	$0
		Demand			$61,982,151	$38,018,190	$887,661	$18,488,310	$1,269,772	$3,312,635	[redacted]	[redacted]	$5,583
		Energy			$51,366,735	$26,002,485	$602,596	$18,477,185	$1,451,906	$4,500,627	[redacted]	[redacted]	$318,780

REDACTED

Jersey Central Power & Light
Depreciation & Amortization Expense
Test Year: July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
403-360P	Land & Land Rights - PRI - Deprec Exp	Total			$96,368	$54,983	$1,039	$30,650	$2,339	$7,067	[redacted]	[redacted]	$290
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$51,281	$32,537	$516	$14,192	$1,030	$3,001	[redacted]	[redacted]	$5
		Energy	AE-PRI-NRG	NRG-PRI	$45,086	$22,446	$523	$16,457	$1,309	$4,066	[redacted]	[redacted]	$285
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
403-360S	Land & Land Rights - SEC - Deprec Exp	Total			$96,368	$59,422	$1,120	$33,000	$2,517	$0	[redacted]	[redacted]	$308
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$52,798	$35,582	$564	$15,520	$1,127	$0	[redacted]	[redacted]	$6
		Energy	AE-SEC-NRG	NRG-SEC	$43,570	$23,841	$556	$17,480	$1,390	$0	[redacted]	[redacted]	$302
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
403-361P	Struct & Impmnts -PRI - Deprec Exp	Total			$337,518	$192,572	$3,639	$107,347	$8,193	$24,751	[redacted]	[redacted]	$1,015
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$179,608	$113,959	$1,806	$49,707	$3,608	$10,510	[redacted]	[redacted]	$18
		Energy	AE-PRI-NRG	NRG-PRI	$157,910	$78,613	$1,833	$57,641	$4,585	$14,241	[redacted]	[redacted]	$997
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
403-361S	Struct & Impmnts -SEC - Deprec Exp	Total			$337,518	$208,121	$3,922	$115,580	$8,816	$0	[redacted]	[redacted]	$1,078
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$184,919	$124,622	$1,975	$54,357	$3,946	$0	[redacted]	[redacted]	$19
		Energy	AE-SEC-NRG	NRG-SEC	$152,598	$83,499	$1,947	$61,223	$4,870	$0	[redacted]	[redacted]	$1,059
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
403-362P	Station Equip - PRI - Deprec Exp	Total			$3,769,171	$2,150,520	$40,643	$1,198,782	$91,494	$276,401	[redacted]	[redacted]	$11,331
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$2,005,740	$1,272,621	$20,170	$555,091	$40,294	$117,367	[redacted]	[redacted]	$198
		Energy	AE-PRI-NRG	NRG-PRI	$1,763,431	$877,899	$20,474	$643,691	$51,200	$159,034	[redacted]	[redacted]	$11,134
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
403-362S	Station Equip - SEC - Deprec Exp	Total			$3,769,171	$2,324,155	$43,803	$1,290,725	$98,446	$0	[redacted]	[redacted]	$12,042
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$2,065,056	$1,391,692	$22,057	$607,027	$44,064	$0	[redacted]	[redacted]	$216
		Energy	AE-SEC-NRG	NRG-SEC	$1,704,115	$932,462	$21,746	$683,698	$54,383	$0	[redacted]	[redacted]	$11,826
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
403-364P	Poles, Towers & Fixt - PRI - Deprec Exp	Total			$9,079,019	$5,180,081	$97,900	$2,887,575	$220,387	$665,782	[redacted]	[redacted]	$27,294
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$4,831,341	$3,065,436	$48,584	$1,337,079	$97,057	$282,708	[redacted]	[redacted]	$476
		Energy	AE-PRI-NRG	NRG-PRI	$4,247,679	$2,114,645	$49,317	$1,550,495	$123,329	$383,074	[redacted]	[redacted]	$26,818
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
403-364S	Poles, Towers & Fixt - SEC - Deprec Exp	Total			$9,079,019	$5,598,325	$105,511	$3,109,044	$237,133	$0	[redacted]	[redacted]	$29,006
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$4,974,220	$3,352,250	$53,129	$1,462,182	$106,138	$0	[redacted]	[redacted]	$521
		Energy	AE-SEC-NRG	NRG-SEC	$4,104,799	$2,246,076	$52,382	$1,646,862	$130,995	$0	[redacted]	[redacted]	$28,485

Jersey Central Power & Light
Depreciation & Amortization Expense
Test Year: July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
403-365P	OH Cond & Dev - PRI - Deprec Exp	Total			$13,455,765	$7,677,256	$145,095	$4,279,595	$326,629	$986,737	[redacted]		$40,452
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$7,160,397	$4,543,198	$72,004	$1,981,649	$143,846	$418,994			$706
		Energy	AE-PRI-NRG	NRG-PRI	$6,295,368	$3,134,058	$73,091	$2,297,947	$182,783	$567,743			$39,746
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-365S	OH Cond & Dev - SEC - Deprec Exp	Total			$13,455,765	$8,297,124	$156,375	$4,607,829	$351,448	$0			$42,989
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$7,372,155	$4,968,277	$78,741	$2,167,059	$157,305	$0			$772
		Energy	AE-SEC-NRG	NRG-SEC	$6,083,610	$3,328,847	$77,633	$2,440,770	$194,143	$0			$42,217
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-366P	UG Conduit - PRI - Deprec Exp	Total			$1,351,211	$770,941	$14,570	$429,752	$32,800	$99,087			$4,062
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$719,038	$456,222	$7,231	$198,995	$14,445	$42,075			$71
		Energy	AE-PRI-NRG	NRG-PRI	$632,173	$314,718	$7,340	$230,757	$18,355	$57,012			$3,991
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-366S	UG Conduit - SEC - Deprec Exp	Total			$150,135	$92,576	$1,745	$51,413	$3,921	$0			$480
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$82,256	$55,434	$879	$24,179	$1,755	$0			$9
		Energy	AE-SEC-NRG	NRG-SEC	$67,879	$37,142	$866	$27,233	$2,166	$0			$471
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-367P	UG Cond & Dev - PRI - Deprec Exp	Total			$5,858,655	$3,342,686	$63,175	$1,863,341	$142,215	$429,627			$17,613
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$3,117,645	$1,978,113	$31,351	$862,812	$62,631	$182,431			$307
		Energy	AE-PRI-NRG	NRG-PRI	$2,741,010	$1,364,572	$31,824	$1,000,529	$79,584	$247,196			$17,306
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-367S	UG Cond & Dev - SEC - Deprec Exp	Total			$5,858,655	$3,612,577	$68,086	$2,006,254	$153,021	$0			$18,717
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$3,209,845	$2,163,193	$34,284	$943,540	$68,491	$0			$336
		Energy	AE-SEC-NRG	NRG-SEC	$2,648,811	$1,449,384	$33,802	$1,062,714	$84,530	$0			$18,381
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-368	Line Transformers - Deprec Exp	Total			$21,448,336	$13,225,521	$249,260	$7,344,827	$560,204	$0			$68,524
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$11,751,131	$7,919,377	$125,513	$3,454,268	$250,742	$0			$1,231
		Energy	AE-SEC-NRG	NRG-SEC	$9,697,205	$5,306,144	$123,747	$3,890,559	$309,462	$0			$67,293
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-369	Services - Deprec Exp	Total			$6,330,609	$4,902,520	$76,536	$1,283,128	$68,094	$0			$332
		Customer	SRVC-CUST	CUST-SVCS	$3,165,305	$2,769,343	$42,728	$352,680	$553	$0			$0
		Demand	SRVC-DMD	DMD-SEC	$3,165,305	$2,133,177	$33,808	$930,448	$67,540	$0			$332
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-370	Meters - Deprec Exp	Total			$10,302,747	$6,840,599	$206,031	$1,783,457	$53,085	$624,211			$0
		Customer	MTR-CUST	CUST-MTR	$8,373,934	$6,086,820	$91,693	$770,346	$5,500	$624,211			$0
		Demand	MTR-DMD	DMD-MTR	$1,928,813	$753,779	$114,338	$1,013,112	$47,585	$0			$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
403-371	Install on Cust Premise - Deprec Exp	Total			$910,175	$0	$0	$0	$0	$0	[redacted]		$910,175
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	DMD-LTG	$910,175	$0	$0	$0	$0	$0			$910,175
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-373	St Lt & Signal Sys - Deprec Exp	Total			$7,189,520	$0	$0	$0	$0	$0			$7,189,520
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	DMD-LTG	$7,189,520	$0	$0	$0	$0	$0			$7,189,520
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-374	Asset Retirement Costs	Total			$850	$485	$9	$270	$21	$62			$3
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$452	$287	$5	$125	$9	$26			$0
		Energy	AE-PRI-NRG	NRG-PRI	$398	$198	$5	$145	$12	$36			$3

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-389	Land & Land Rights - Deprec Exp	Total			$377	$198	$4	$111	$8	$26			$1
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$193	$116	$2	$50	$4	$11			$0
		Energy	AE-ALL-NRG	NRG-All	$184	$83	$2	$61	$5	$15			$1

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-390	Struct & Impmnts - Deprec Exp	Total			$1,494,037	$786,326	$14,915	$440,481	$33,648	$101,709			$4,234
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$765,369	$458,077	$7,260	$199,804	$14,504	$42,246			$71
		Energy	AE-ALL-NRG	NRG-All	$728,668	$328,249	$7,655	$240,678	$19,144	$59,463			$4,163

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-391	Office Furn & Equip - Deprec Exp	Total			$1,903,796	$1,001,986	$19,006	$561,289	$42,876	$129,604			$5,395
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$975,281	$583,710	$9,251	$254,602	$18,481	$53,832			$91
		Energy	AE-ALL-NRG	NRG-All	$928,514	$418,275	$9,755	$306,687	$24,394	$75,772			$5,305

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-392	Transportation Equip - Deprec Exp	Total			$535,910	$282,055	$5,350	$158,000	$12,069	$36,483			$1,519
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$274,537	$164,312	$2,604	$71,669	$5,202	$15,154			$26
		Energy	AE-ALL-NRG	NRG-All	$261,373	$117,743	$2,746	$86,331	$6,867	$21,329			$1,493

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-393	Stores Equip - Deprec Exp	Total			$44,353	$23,343	$443	$13,076	$999	$3,019			$126
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$22,721	$13,599	$216	$5,931	$431	$1,254			$2
		Energy	AE-ALL-NRG	NRG-All	$21,632	$9,745	$227	$7,145	$568	$1,765			$124

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-394	Tools, Shop & Garage Equip - Deprec Exp	Total			$1,215,535	$639,748	$12,135	$358,372	$27,375	$82,750			$3,445
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$622,697	$372,687	$5,907	$162,558	$11,800	$34,371			$58
		Energy	AE-ALL-NRG	NRG-All	$592,838	$267,060	$6,228	$195,813	$15,575	$48,379			$3,387

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
403-396	Power Operated Equip - Deprec Exp	Total			$16,999	$8,947	$170	$5,012	$383	$1,157	[redacted]		$48
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$8,708	$5,212	$83	$2,273	$165	$481			$1
		Energy	AE-ALL-NRG	NRG-All	$8,291	$3,735	$87	$2,738	$218	$677			$47
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-397	Communication Equip - Deprec Exp	Total			$1,691,857	$890,440	$16,890	$498,804	$38,103	$115,176			$4,795
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$866,708	$518,729	$8,221	$226,259	$16,424	$47,840			$81
		Energy	AE-ALL-NRG	NRG-All	$825,148	$371,711	$8,669	$272,545	$21,679	$67,336			$4,714
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-398	MISC Equip - Deprec Exp	Total			$17,967	$9,456	$179	$5,297	$405	$1,223			$51
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$9,204	$5,509	$87	$2,403	$174	$508			$1
		Energy	AE-ALL-NRG	NRG-All	$8,763	$3,948	$92	$2,894	$230	$715			$50
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-399	Other Tangible Property - Deprec Exp	Total			$70,511	$37,110	$704	$20,788	$1,588	$4,800			$200
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$36,121	$21,619	$343	$9,430	$684	$1,994			$3
		Energy	AE-ALL-NRG	NRG-All	$34,389	$15,492	$361	$11,359	$903	$2,806			$196
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403 (360-374)	Distribution Plant Depreciation Exp	Total			$112,875,724	$64,529,978	$1,278,452	$32,422,299	$2,360,741	$3,113,663			$8,375,228
		Customer			$11,539,239	$8,856,163	$134,421	$1,123,026	$6,053	$624,211			$0
		Demand			$60,951,243	$34,359,470	$646,949	$15,671,217	$1,111,602	$1,057,086			$8,104,918
		Energy			$40,385,242	$21,314,345	$497,081	$15,628,056	$1,243,085	$1,432,366			$270,309
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403 (389-399)	General Plant - Deprec Expense	Total			$6,992,192	$3,680,094	$69,805	$2,061,502	$157,474	$476,010			$19,816
		Customer			$0	$0	$0	$0	$0	$0			$0
		Demand			$3,581,994	$2,143,857	$33,978	$935,106	$67,878	$197,716			$333
		Energy			$3,410,198	$1,536,237	$35,827	$1,126,396	$89,596	$278,294			$19,483
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403 (360-399)	Total - Unadjusted Deprec Expense	Total			$119,867,916	$68,210,072	$1,348,256	$34,483,801	$2,518,215	$3,589,672			$8,395,044
		Customer			$11,539,239	$8,856,163	$134,421	$1,123,026	$6,053	$624,211			$0
		Demand			$64,533,237	$36,503,327	$680,927	$16,606,323	$1,179,481	$1,254,802			$8,105,252
		Energy			$43,795,440	$22,850,582	$532,908	$16,754,452	$1,332,681	$1,710,660			$289,792
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-DEPRC	Adjs to Depreciation Exp	Total			$25,777,280	$14,795,188	$288,597	$7,491,380	$548,997	$746,644			$1,686,546
		Customer	See Adjustments	See Adjustments	$2,318,258	$1,808,871	$27,516	$229,509	$1,120	$110,476			$0
		Demand	See Adjustments	See Adjustments	$13,960,072	$8,015,941	$145,165	$3,617,503	$257,997	$269,472			$1,623,512
		Energy	See Adjustments	See Adjustments	$9,498,949	$4,970,376	$115,916	$3,644,368	$289,880	$366,697			$63,035
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-TOTDPREXP	Total Adjusted Depreciation Exp	Total			$145,645,195	$83,005,261	$1,636,854	$41,975,181	$3,067,212	$4,336,316			$10,081,590
		Customer			$13,857,497	$10,665,034	$161,937	$1,352,536	$7,172	$734,687			$0
		Demand			$78,493,309	$44,519,268	$826,092	$20,223,826	$1,437,478	$1,524,273			$9,728,763
		Energy			$53,294,389	$27,820,959	$648,825	$20,398,820	$1,622,561	$2,077,356			$352,826

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
404	Amort - Ltd Term Elec Prpty	Total			$8,815,151	$5,159,704	$97,633	$2,621,666	$193,635	$235,346	[redacted]		$482,938
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$663,870	$543,063	$8,311	$69,013	$239	$19,015	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$4,839,032	$2,872,344	$48,642	$1,273,703	$91,666	$91,860	[redacted]		$460,817
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$3,312,249	$1,744,297	$40,680	$1,278,950	$101,730	$124,472	[redacted]		$22,121
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
407-TMI/OC	Amort - TMI and OC	Total			$109,008	$49,106	$1,145	$36,005	$2,864	$8,896	[redacted]		$623
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Energy	NRG	NRG-ALL	$109,008	$49,106	$1,145	$36,005	$2,864	$8,896	[redacted]		$623
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
407-STRM	Amort - Storm Exp	Total			$25,566,878	$13,456,090	$255,238	$7,537,790	$575,797	$1,740,509	[redacted]		$72,456
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$13,097,464	$7,838,895	$124,237	$3,419,164	$248,194	$722,938	[redacted]		$1,218
		Energy	AE-ALL-NRG	NRG-ALL	$12,469,414	$5,617,194	$131,001	$4,118,626	$327,603	$1,017,570	[redacted]		$71,237
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
407-COR	Amort - Cost of Removal	Total			($3,124,154)	($1,828,637)	($34,602)	($929,138)	($68,626)	($83,408)	[redacted]		($171,157)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($235,280)	($192,466)	($2,946)	($24,459)	($85)	($6,739)	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($1,714,989)	($1,017,980)	($17,239)	($451,410)	($32,487)	($32,556)	[redacted]		($163,317)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($1,173,886)	($618,192)	($14,417)	($453,269)	($36,054)	($44,114)	[redacted]		($7,840)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
407-ARO	Amort - ARO ACCR & DEP	Total			($9,421,269)	($4,958,503)	($94,054)	($2,777,639)	($212,178)	($641,369)	[redacted]		($26,700)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($4,826,351)	($2,888,594)	($45,781)	($1,259,945)	($91,458)	($266,399)	[redacted]		($449)
		Energy	AE-ALL-NRG	NRG-ALL	($4,594,918)	($2,069,908)	($48,273)	($1,517,694)	($120,720)	($374,970)	[redacted]		($26,251)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
411.1- Accretion	Accretion Expense	Total			$9,380,189	$4,936,882	$93,644	$2,765,527	$211,253	$638,572	[redacted]		$26,583
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$4,805,306	$2,875,999	$45,581	$1,254,451	$91,059	$265,238	[redacted]		$447
		Energy	AE-ALL-NRG	NRG-ALL	$4,574,883	$2,060,883	$48,063	$1,511,076	$120,194	$373,335	[redacted]		$26,136
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
404, 407	Amortization Expense	Total			$31,325,803	$16,814,642	$319,005	$9,254,212	$702,745	$1,898,546	[redacted]		$384,744
		Customer			$428,589	$350,598	$5,366	$44,554	$154	$12,276	[redacted]		$0
		Demand			$16,200,463	$9,680,664	$155,441	$4,235,963	$306,974	$781,081	[redacted]		$298,716
		Energy			$14,696,751	$6,783,380	$158,198	$4,973,694	$395,617	$1,105,189	[redacted]		$86,027
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-AMORT	Adjs to Amortization Exp	Total			$82,185,866	$43,520,510	$826,647	$24,332,125	$1,857,004	$5,487,830	[redacted]		$255,786
		Customer			$148,632	$107,254	$1,616	$13,575	$96	$10,877	[redacted]		$0
		Demand			$42,157,381	$25,323,202	$403,165	$11,057,629	$802,201	$2,276,383	[redacted]		$26,423
		Energy			$39,879,854	$18,090,054	$421,866	$13,260,921	$1,054,707	$3,200,569	[redacted]		$229,362
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-TOTAMORTEXP	Total Adj Amort Exp	Total			$113,511,669	$60,335,152	$1,145,652	$33,586,336	$2,559,749	$7,386,375	[redacted]		$640,529
		Customer			$577,221	$457,852	$6,982	$58,129	$250	$23,153	[redacted]		$0
		Demand			$58,357,843	$35,003,866	$558,606	$15,293,592	$1,109,175	$3,057,464	[redacted]		$325,140
		Energy			$54,576,604	$24,873,434	$580,064	$18,234,615	$1,450,324	$4,305,758	[redacted]		$315,389

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Jersey Central Power & Light
Taxes Other Than Income
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
408-PPTYTX	Txs Otr Inc - Property Tax	Total			$4,935,959	$2,865,926	$54,239	$1,466,963	$108,642	$148,048	[redacted]		$249,992
		Customer	RB-PLT-CUST	RB-PLT-CUST	$342,119	$279,863	$4,283	$35,565	$123	$9,799	[redacted]		$0
		Demand	RB-PLT-DMD	RB-PLT-DMD	$2,695,156	$1,600,778	$26,978	$708,969	$51,056	$58,456	[redacted]		$237,497
		Energy	RB-PLT-NRG	RB-PLT-NRG	$1,898,684	$985,285	$22,978	$722,429	$57,463	$79,793	[redacted]		$12,495
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
408-PAY	Txs Otr Inc - Payroll & Unemp	Total			$4,621,369	$2,700,277	$56,300	$1,358,518	$97,665	$256,254	[redacted]		$93,201
		Customer	PAY-CUST	PAY-CUST	$569,863	$410,394	$6,182	$51,939	$371	$42,086	[redacted]		$0
		Demand	PAY-DMD	PAY-DMD	$2,264,999	$1,372,647	$28,803	$645,827	$45,093	$90,839	[redacted]		$81,789
		Energy	PAY-NRG	PAY-NRG	$1,786,507	$917,236	$21,315	$660,751	$52,201	$123,328	[redacted]		$11,412
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
TOTTXOTR	Total Taxes Other Than Income	Total			$9,557,328	$5,566,203	$110,539	$2,825,481	$206,307	$404,302	[redacted]		$343,193
		Customer			$911,982	$690,257	$10,465	$87,505	$494	$51,885	[redacted]		$0
		Demand			$4,960,155	$2,973,425	$55,781	$1,354,796	$96,149	$149,295	[redacted]		$319,286
		Energy			$3,685,191	$1,902,521	$44,293	$1,383,180	$109,664	$203,121	[redacted]		$23,908

Jersey Central Power & Light
Plant In Service
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
301	Organization	Total			$45,044	$23,707	$450	$13,280	$1,014	$3,066	[redacted]		$128
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$23,075	$13,811	$219	$6,024	$437	$1,274	[redacted]		$2
		Energy	AE-ALL-NRG	NRG-ALL	$21,969	$9,897	$231	$7,256	$577	$1,793	[redacted]		$126
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
302	Franchise and Consents	Total			$15,029	$7,910	$150	$4,431	$338	$1,023	[redacted]		$43
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$7,699	$4,608	$73	$2,010	$146	$425	[redacted]		$1
		Energy	AE-ALL-NRG	NRG-ALL	$7,330	$3,302	$77	$2,421	$193	$598	[redacted]		$42
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
303	Misc Intangible Plant	Total			$126,008,783	$66,319,614	$1,257,966	$37,150,713	$2,837,871	$8,578,262	[redacted]		$357,106
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$64,552,091	$38,634,740	$612,316	$16,851,672	$1,223,246	$3,563,070	[redacted]		$6,005
		Energy	AE-ALL-NRG	NRG-ALL	$61,456,692	$27,684,875	$645,651	$20,299,041	$1,614,624	$5,015,192	[redacted]		$351,101
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
TOTINTPLT	Total Intangible PIS	Total			$126,068,856	$66,351,232	$1,258,566	$37,168,424	$2,839,224	$8,582,352	[redacted]		$357,276
		Customer			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			$64,582,866	$38,653,158	$612,607	$16,859,706	$1,223,830	$3,564,769	[redacted]		$6,008
		Energy			$61,485,991	$27,698,073	$645,959	$20,308,718	$1,615,394	$5,017,582	[redacted]		$351,268

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
360P	Land & Land Rights - PRI	Total			$16,328,813	$9,316,488	$176,076	$5,193,366	$396,370	$1,197,424	[redacted]	[redacted]	$49,090
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$8,689,271	$5,513,253	$87,379	$2,404,766	$174,560	$508,457	[redacted]	[redacted]	$857
		Energy	AE-PRI-NRG	NRG-PRI	$7,639,542	$3,803,236	$88,697	$2,788,600	$221,811	$688,967	[redacted]	[redacted]	$48,233
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
360S	Land & Land Rights - SEC	Total			$16,328,813	$10,068,710	$189,764	$5,591,684	$426,489	$0	[redacted]	[redacted]	$52,168
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$8,946,243	$6,029,094	$95,554	$2,629,766	$190,892	$0	[redacted]	[redacted]	$937
		Energy	AE-SEC-NRG	NRG-SEC	$7,382,570	$4,039,616	$94,210	$2,961,918	$235,597	$0	[redacted]	[redacted]	$51,231
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
361P	Struct & Impmnts -PRI	Total			$29,850,055	$17,031,102	$321,877	$9,493,786	$724,589	$2,188,963	[redacted]	[redacted]	$89,739
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$15,884,511	$10,078,558	$159,733	$4,396,058	$319,106	$929,490	[redacted]	[redacted]	$1,566
		Energy	AE-PRI-NRG	NRG-PRI	$13,965,544	$6,952,544	$162,143	$5,097,728	$405,483	$1,259,473	[redacted]	[redacted]	$88,172
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
361S	Struct & Impmnts -SEC	Total			$29,850,055	$18,406,208	$346,900	$10,221,935	$779,647	$0	[redacted]	[redacted]	$95,366
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$16,354,271	$11,021,547	$174,679	$4,807,370	$348,962	$0	[redacted]	[redacted]	$1,713
		Energy	AE-SEC-NRG	NRG-SEC	$13,495,784	$7,384,661	$172,221	$5,414,564	$430,685	$0	[redacted]	[redacted]	$93,653
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
362P	Station Equip - PRI	Total			$263,927,736	$150,585,322	$2,845,964	$83,942,007	$6,406,655	$19,354,335	[redacted]	[redacted]	$793,452
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$140,447,417	$89,112,431	$1,412,328	$38,868,993	$2,821,462	$8,218,352	[redacted]	[redacted]	$13,850
		Energy	AE-PRI-NRG	NRG-PRI	$123,480,319	$61,472,891	$1,433,636	$45,073,014	$3,585,193	$11,135,984	[redacted]	[redacted]	$779,602
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
362S	Station Equip - SEC	Total			$263,927,736	$162,743,715	$3,067,211	$90,380,137	$6,893,471	$0	[redacted]	[redacted]	$843,202
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$144,600,932	$97,450,138	$1,544,471	$42,505,728	$3,085,449	$0	[redacted]	[redacted]	$15,146
		Energy	AE-SEC-NRG	NRG-SEC	$119,326,803	$65,293,578	$1,522,740	$47,874,409	$3,808,022	$0	[redacted]	[redacted]	$828,056
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
364P	Poles, Towers & Fixt - PRI	Total			$376,540,833	$214,837,301	$4,060,284	$119,758,513	$9,140,257	$27,612,473	[redacted]	[redacted]	$1,132,003
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$200,373,739	$127,135,062	$2,014,942	$55,453,676	$4,025,328	$11,724,971	[redacted]	[redacted]	$19,760
		Energy	AE-PRI-NRG	NRG-PRI	$176,167,094	$87,702,240	$2,045,342	$64,304,837	$5,114,929	$15,887,503	[redacted]	[redacted]	$1,112,243
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
364S	Poles, Towers & Fixt - SEC	Total			$376,540,833	$232,183,457	$4,375,933	$128,943,675	$9,834,788	$0	[redacted]	[redacted]	$1,202,981
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$206,299,483	$139,030,314	$2,203,468	$60,642,138	$4,401,953	$0	[redacted]	[redacted]	$21,609
		Energy	AE-SEC-NRG	NRG-SEC	$170,241,349	$93,153,143	$2,172,464	$68,301,536	$5,432,834	$0	[redacted]	[redacted]	$1,181,372
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
365P	OH Cond & Dev - PRI	Total			$591,926,189	$337,726,520	$6,382,810	$188,261,655	$14,368,581	$43,407,102	[redacted]	[redacted]	$1,779,521
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$314,989,646	$199,857,668	$3,167,511	$87,173,768	$6,327,858	$18,431,778	[redacted]	[redacted]	$31,063
		Energy	AE-PRI-NRG	NRG-PRI	$276,936,543	$137,868,853	$3,215,299	$101,087,887	$8,040,723	$24,975,323	[redacted]	[redacted]	$1,748,458
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
365S	OH Cond & Dev - SEC	Total			$591,926,189	$364,994,861	$6,879,013	$202,700,826	$15,460,390	$0	[redacted]	[redacted]	$1,891,098
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$324,304,980	$218,557,131	$3,463,876	$95,330,086	$6,919,917	$0	[redacted]	[redacted]	$33,970
		Energy	AE-SEC-NRG	NRG-SEC	$267,621,210	$146,437,730	$3,415,137	$107,370,740	$8,540,473	$0	[redacted]	[redacted]	$1,857,129

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366P	UG Conduit - PRI	Total			$105,486,511	$60,185,869	$1,137,473	$33,549,901	$2,560,609	$7,735,532	[redacted]		$317,127
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$56,133,956	$35,616,414	$564,479	$15,535,141	$1,127,681	$3,284,707			$5,536
		Energy	AE-PRI-NRG	NRG-PRI	$49,352,555	$24,569,456	$572,995	$18,014,761	$1,432,928	$4,450,825			$311,591
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
366S	UG Conduit - SEC	Total			$11,720,723	$7,227,259	$136,211	$4,013,677	$306,131	$0			$37,446
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$6,421,559	$4,327,647	$68,588	$1,887,630	$137,021	$0			$673
		Energy	AE-SEC-NRG	NRG-SEC	$5,299,164	$2,899,612	$67,623	$2,126,047	$169,110	$0			$36,773
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
367P	UG Cond & Dev - PRI	Total			$310,333,678	$177,062,470	$3,346,364	$98,701,380	$7,533,126	$22,757,374			$932,963
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$165,142,035	$104,780,911	$1,660,655	$45,703,259	$3,317,555	$9,663,370			$16,286
		Energy	AE-PRI-NRG	NRG-PRI	$145,191,643	$72,281,560	$1,685,709	$52,998,121	$4,215,571	$13,094,004			$916,678
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
367S	UG Cond & Dev - SEC	Total			$310,333,678	$191,358,652	$3,606,513	$106,271,515	$8,105,537	$0			$991,461
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$170,025,856	$114,584,621	$1,816,033	$49,979,434	$3,627,958	$0			$17,809
		Energy	AE-SEC-NRG	NRG-SEC	$140,307,822	$76,774,031	$1,790,480	$56,292,081	$4,477,579	$0			$973,651
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
368	Line Transformers	Total			$853,891,746	$526,528,653	$9,923,420	$292,409,029	$22,302,611	$0			$2,728,032
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$467,830,872	$315,282,773	$4,996,864	$137,519,804	$9,982,428	$0			$49,003
		Energy	AE-SEC-NRG	NRG-SEC	$386,060,874	$211,245,881	$4,926,556	$154,889,225	$12,320,184	$0			$2,679,028
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
369	Services	Total			$469,594,395	$363,661,012	$5,677,353	$95,180,363	$5,051,072	$0			$24,594
		Customer	SRVC-CUST	CUST-SVCS	$234,797,197	$205,425,385	$3,169,503	$26,161,266	$41,043	$0			$0
		Demand	SRVC-DMD	DMD-SEC	$234,797,197	$158,235,627	$2,507,850	$69,019,097	$5,010,029	$0			$24,594
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
370	Meters	Total			$180,264,239	$119,688,011	$3,604,873	$31,204,644	$928,806	$10,921,646			$0
		Customer	MTR-CUST	CUST-MTR	$146,516,339	$106,499,359	$1,604,331	$13,478,519	$96,226	$10,921,646			$0
		Demand	MTR-DMD	DMD-MTR	$33,747,900	$13,188,653	$2,000,543	$17,726,125	$832,580	$0			$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
371	Install on Cust Premise	Total			$25,980,444	$0	$0	$0	$0	$0			$25,980,444
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	DMD-LTG	$25,980,444	$0	$0	$0	$0	$0			$25,980,444
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
373	St Lt & Signal Sys	Total			$238,449,297	$0	$0	$0	$0	$0			$238,449,297
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	DMD-LTG	$238,449,297	$0	$0	$0	$0	$0			$238,449,297
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
374	Asset Retirement Costs	Total			$45,657	$26,050	$492	$14,521	$1,108	$3,348			$137
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$24,296	$15,416	$244	$6,724	$488	$1,422			$2
		Energy	AE-PRI-NRG	NRG-PRI	$21,361	$10,634	$248	$7,797	$620	$1,926			$135
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
TOTDISTPLT	Total Distribution PIS	Total			$5,063,247,618	$2,963,631,662	$56,078,529	$1,505,832,615	$111,220,238	$135,178,196			$277,390,119
		Customer			$381,313,536	$311,924,744	$4,773,834	$39,639,785	$137,269	$10,921,646			$0
		Demand			$2,779,443,906	$1,649,817,255	$27,939,197	$731,589,565	$52,651,227	$52,762,546			$264,684,116
		Energy			$1,902,490,176	$1,001,889,663	$23,365,499	$734,603,265	$58,431,742	$71,494,005			$12,706,003

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389	Land & Land Rights	Total			$1,494,290	$786,459	$14,918	$440,556	$33,653	$101,726	[redacted]	[redacted]	$4,235
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$765,499	$458,155	$7,261	$199,838	$14,506	$42,253	[redacted]	[redacted]	$71
		Energy	AE-ALL-NRG	NRG-ALL	$728,791	$328,304	$7,657	$240,719	$19,147	$59,473	[redacted]	[redacted]	$4,164
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
390	Struct & Impmnts	Total			$92,717,272	$48,797,977	$925,612	$27,335,497	$2,088,105	$6,311,886	[redacted]	[redacted]	$262,758
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$47,497,434	$28,427,444	$450,542	$12,399,461	$900,065	$2,621,708	[redacted]	[redacted]	$4,418
		Energy	AE-ALL-NRG	NRG-ALL	$45,219,839	$20,370,533	$475,070	$14,936,036	$1,188,041	$3,690,178	[redacted]	[redacted]	$258,340
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
391	Office Furn & Equip	Total			$29,278,765	$15,409,691	$292,295	$8,632,152	$659,393	$1,993,202	[redacted]	[redacted]	$82,975
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$14,998,998	$8,976,973	$142,275	$3,915,569	$284,227	$827,897	[redacted]	[redacted]	$1,395
		Energy	AE-ALL-NRG	NRG-ALL	$14,279,767	$6,432,718	$150,020	$4,716,583	$375,166	$1,165,305	[redacted]	[redacted]	$81,580
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
392	Transportation Equip	Total			$8,780,078	$4,621,038	$87,653	$2,588,598	$197,738	$597,719	[redacted]	[redacted]	$24,883
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$4,497,880	$2,692,003	$42,665	$1,174,196	$85,234	$248,269	[redacted]	[redacted]	$418
		Energy	AE-ALL-NRG	NRG-ALL	$4,282,198	$1,929,035	$44,988	$1,414,403	$112,504	$349,450	[redacted]	[redacted]	$24,464
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
393	Stores Equip	Total			$1,490,362	$784,391	$14,879	$439,398	$33,565	$101,459	[redacted]	[redacted]	$4,224
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$763,486	$456,950	$7,242	$199,312	$14,468	$42,142	[redacted]	[redacted]	$71
		Energy	AE-ALL-NRG	NRG-ALL	$726,875	$327,441	$7,636	$240,086	$19,097	$59,317	[redacted]	[redacted]	$4,153
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
394	Tools, Shop & Garage Equip	Total			$23,055,243	$12,134,192	$230,164	$6,797,294	$519,232	$1,569,525	[redacted]	[redacted]	$65,338
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$11,810,797	$7,068,819	$112,033	$3,083,272	$223,812	$651,918	[redacted]	[redacted]	$1,099
		Energy	AE-ALL-NRG	NRG-ALL	$11,244,446	$5,065,373	$118,132	$3,714,021	$295,420	$917,606	[redacted]	[redacted]	$64,239
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
395	Laboratory Equip	Total			$448,981	$236,303	$4,482	$132,371	$10,112	$30,565	[redacted]	[redacted]	$1,272
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$230,005	$137,659	$2,182	$60,044	$4,359	$12,696	[redacted]	[redacted]	$21
		Energy	AE-ALL-NRG	NRG-ALL	$218,976	$98,644	$2,301	$72,327	$5,753	$17,870	[redacted]	[redacted]	$1,251

REDACTED

Jersey Central Power & Light
Plant In Service
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
396	Power Operated Equip	Total			$3,851,265	$2,026,957	$38,448	$1,135,454	$86,735	$262,181	[redacted]		$10,914
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$1,972,935	$1,180,811	$18,714	$515,045	$37,387	$108,900	[redacted]		$184
		Energy	AE-ALL-NRG	NRG-ALL	$1,878,329	$846,146	$19,733	$620,409	$49,349	$153,282	[redacted]		$10,731
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
397	Communication Equip	Total			$36,284,526	$19,096,890	$362,234	$10,697,635	$817,172	$2,470,131	[redacted]		$102,829
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$18,587,927	$11,124,964	$176,318	$4,852,479	$352,237	$1,025,995	[redacted]		$1,729
		Energy	AE-ALL-NRG	NRG-ALL	$17,696,599	$7,971,925	$185,917	$5,845,157	$464,935	$1,444,136	[redacted]		$101,100
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
398	MISC Equip	Total			$1,384,722	$728,792	$13,824	$408,253	$31,186	$94,267	[redacted]		$3,924
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$709,369	$424,561	$6,729	$185,185	$13,442	$39,155	[redacted]		$66
		Energy	AE-ALL-NRG	NRG-ALL	$675,353	$304,232	$7,095	$223,068	$17,743	$55,112	[redacted]		$3,858
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
399	Other Tangible Property	Total			$1,458,070	$767,396	$14,556	$429,877	$32,837	$99,261	[redacted]		$4,132
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$746,944	$447,049	$7,085	$194,994	$14,154	$41,229	[redacted]		$69
		Energy	AE-ALL-NRG	NRG-ALL	$711,126	$320,347	$7,471	$234,884	$18,683	$58,032	[redacted]		$4,063
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
SRVCO-PIS	Service Company PIS	Total			$114,476,272	$60,249,945	$1,142,835	$33,750,624	$2,578,145	$7,793,167	[redacted]		$324,423
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$58,644,188	$35,098,831	$556,276	$15,309,382	$1,111,293	$3,236,973	[redacted]		$5,455
		Energy	AE-ALL-NRG	NRG-ALL	$55,832,084	$25,151,114	$586,560	$18,441,243	$1,466,852	$4,556,194	[redacted]		$318,967
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
TOTGENPLT	Total General PIS	Total			$314,719,845	$165,640,032	$3,141,900	$92,787,712	$7,087,873	$21,425,088	[redacted]		$891,908
		Customer			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			$161,225,461	$96,494,221	$1,529,321	$42,088,777	$3,055,183	$8,899,134	[redacted]		$14,998
		Energy			$153,494,384	$69,145,811	$1,612,579	$50,698,935	$4,032,690	$12,525,955	[redacted]		$876,910

REDACTED

Jersey Central Power & Light
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
108-303	Misc Intangible Plant - Accum Res	Total			($86,519,616)	($45,536,092)	($863,740)	($25,508,265)	($1,948,527)	($5,889,970)	[redacted]		($245,194)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	($44,322,483)	($26,527,221)	($420,426)	($11,570,623)	($839,900)	($2,446,460)			($4,123)
		Energy	AE-ALL-NRG	NRG-ALL	($42,197,133)	($19,008,871)	($443,314)	($13,937,641)	($1,108,627)	($3,443,510)			($241,071)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-360P	Land & Land Rights - PRI - Accum Res	Total			($9,226,449)	($5,264,198)	($99,490)	($2,934,465)	($223,965)	($676,594)			($27,738)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	($4,909,794)	($3,115,214)	($49,373)	($1,358,792)	($98,633)	($287,299)			($484)
		Energy	AE-PRI-NRG	NRG-PRI	($4,316,655)	($2,148,984)	($50,117)	($1,575,673)	($125,332)	($389,294)			($27,253)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-360S	Land & Land Rights - SEC - Accum Res	Total			($9,226,449)	($5,689,234)	($107,224)	($3,159,531)	($240,984)	$0			($29,477)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	($5,054,994)	($3,406,685)	($53,992)	($1,485,925)	($107,862)	$0			($529)
		Energy	AE-SEC-NRG	NRG-SEC	($4,171,455)	($2,282,549)	($53,232)	($1,673,605)	($133,122)	$0			($28,947)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-361P	Struct & Impmnts -PRI - Accum Res	Total			($7,132,242)	($4,069,337)	($76,908)	($2,268,404)	($173,130)	($523,021)			($21,442)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	($3,795,376)	($2,408,127)	($38,166)	($1,050,375)	($76,246)	($222,088)			($374)
		Energy	AE-PRI-NRG	NRG-PRI	($3,336,866)	($1,661,210)	($38,742)	($1,218,029)	($96,884)	($300,933)			($21,068)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-361S	Struct & Impmnts -SEC - Accum Res	Total			($7,132,242)	($4,397,899)	($82,887)	($2,442,384)	($186,285)	$0			($22,786)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	($3,907,618)	($2,633,440)	($41,737)	($1,148,652)	($83,380)	$0			($409)
		Energy	AE-SEC-NRG	NRG-SEC	($3,224,624)	($1,764,459)	($41,150)	($1,293,732)	($102,906)	$0			($22,377)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-362P	Station Equip - PRI - Accum Res	Total			($97,058,405)	($55,377,170)	($1,046,592)	($30,869,349)	($2,356,023)	($7,117,482)			($291,789)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	($51,648,995)	($32,770,752)	($519,378)	($14,293,922)	($1,037,582)	($3,022,267)			($5,093)
		Energy	AE-PRI-NRG	NRG-PRI	($45,409,410)	($22,606,418)	($527,214)	($16,575,427)	($1,318,441)	($4,095,215)			($286,695)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-362S	Station Equip - SEC - Accum Res	Total			($97,058,405)	($59,848,372)	($1,127,955)	($33,236,946)	($2,535,047)	$0			($310,084)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	($53,176,434)	($35,836,911)	($567,973)	($15,631,317)	($1,134,662)	$0			($5,570)
		Energy	AE-SEC-NRG	NRG-SEC	($43,881,971)	($24,011,461)	($559,982)	($17,605,629)	($1,400,385)	$0			($304,514)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-364P	Poles, Towers & Fixt - PRI - Accum Res	Total			($126,225,561)	($72,018,641)	($1,361,105)	($40,145,940)	($3,064,034)	($9,256,367)			($379,475)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	($67,170,106)	($42,618,737)	($675,457)	($18,589,409)	($1,349,387)	($3,930,493)			($6,624)
		Energy	AE-PRI-NRG	NRG-PRI	($59,055,455)	($29,399,904)	($685,648)	($21,556,531)	($1,714,648)	($5,325,874)			($372,851)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-364S	Poles, Towers & Fixt - SEC - Accum Res	Total			($126,225,561)	($77,833,490)	($1,466,918)	($43,225,027)	($3,296,858)	$0			($403,268)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	($69,156,558)	($46,606,312)	($738,656)	($20,328,706)	($1,475,641)	$0			($7,244)
		Energy	AE-SEC-NRG	NRG-SEC	($57,069,003)	($31,227,178)	($728,262)	($22,896,321)	($1,821,217)	$0			($396,024)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-365P	OH Cond & Dev - PRI - Accum Res	Total			($91,701,795)	($52,320,929)	($988,831)	($29,165,683)	($2,225,995)	($6,724,671)			($275,685)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	($48,798,510)	($30,962,149)	($490,714)	($13,505,047)	($980,318)	($2,855,469)			($4,812)
		Energy	AE-PRI-NRG	NRG-PRI	($42,903,285)	($21,358,780)	($498,117)	($15,660,636)	($1,245,677)	($3,869,202)			($270,873)

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
108-365S	OH Cond & Dev - SEC - Accum Res	Total			($91,701,795)	($56,545,367)	($1,065,704)	($31,402,614)	($2,395,139)	$0	[redacted]		($292,971)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	($50,241,650)	($33,859,088)	($536,627)	($14,768,632)	($1,072,041)	$0	[redacted]		($5,263)
		Energy	AE-SEC-NRG	NRG-SEC	($41,460,144)	($22,686,279)	($529,076)	($16,633,982)	($1,323,099)	$0	[redacted]		($287,708)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-366P	UG Conduit - PRI - Accum Res	Total			($53,567,324)	($30,563,111)	($577,623)	($17,037,045)	($1,300,308)	($3,928,196)	[redacted]		($161,041)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	($28,505,501)	($18,086,445)	($286,649)	($7,888,932)	($572,650)	($1,668,014)	[redacted]		($2,811)
		Energy	AE-PRI-NRG	NRG-PRI	($25,061,823)	($12,476,666)	($290,974)	($9,148,113)	($727,658)	($2,260,183)	[redacted]		($158,230)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-366S	UG Conduit - SEC - Accum Res	Total			($5,951,925)	($3,670,089)	($69,170)	($2,038,193)	($155,457)	$0	[redacted]		($19,015)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	($3,260,945)	($2,197,631)	($34,830)	($958,561)	($69,581)	$0	[redacted]		($342)
		Energy	AE-SEC-NRG	NRG-SEC	($2,690,980)	($1,472,458)	($34,340)	($1,079,632)	($85,876)	$0	[redacted]		($18,674)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-367P	UG Cond & Dev - PRI - Accum Res	Total			($111,484,593)	($63,608,106)	($1,202,151)	($35,457,586)	($2,706,208)	($8,175,383)	[redacted]		($335,159)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	($59,325,796)	($37,641,603)	($596,576)	($16,418,486)	($1,191,802)	($3,471,479)	[redacted]		($5,850)
		Energy	AE-PRI-NRG	NRG-PRI	($52,158,797)	($25,966,503)	($605,576)	($19,039,100)	($1,514,406)	($4,703,904)	[redacted]		($329,308)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-367S	UG Cond & Dev - SEC - Accum Res	Total			($111,484,593)	($68,743,881)	($1,295,607)	($38,177,090)	($2,911,842)	$0	[redacted]		($356,173)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	($61,080,265)	($41,163,498)	($652,393)	($17,954,664)	($1,303,311)	$0	[redacted]		($6,398)
		Energy	AE-SEC-NRG	NRG-SEC	($50,404,328)	($27,580,383)	($643,214)	($20,222,426)	($1,608,530)	$0	[redacted]		($349,775)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-368	Line Transformers - Accum Res	Total			($289,146,526)	($178,294,183)	($3,360,288)	($99,016,129)	($7,552,155)	$0	[redacted]		($923,772)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	($158,417,823)	($106,761,681)	($1,692,048)	($46,567,230)	($3,380,270)	$0	[redacted]		($16,594)
		Energy	AE-SEC-NRG	NRG-SEC	($130,728,703)	($71,532,501)	($1,668,240)	($52,448,898)	($4,171,885)	$0	[redacted]		($907,178)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-369	Services - Accum Res	Total			($189,580,347)	($146,813,893)	($2,292,009)	($38,425,344)	($2,039,172)	$0	[redacted]		($9,929)
		Customer	SRVC-CUST	CUST-SVCS	($94,790,174)	($82,932,455)	($1,279,563)	($10,561,586)	($16,570)	$0	[redacted]		$0
		Demand	SRVC-DMD	DMD-SEC	($94,790,174)	($63,881,438)	($1,012,446)	($27,863,758)	($2,022,603)	$0	[redacted]		($9,929)
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-370	Meters - Accum Res	Total			($35,341,484)	($23,465,286)	($706,749)	($6,117,788)	($182,096)	($2,141,230)	[redacted]		$0
		Customer	MTR-CUST	CUST-MTR	($28,725,081)	($20,879,601)	($314,535)	($2,642,514)	($18,865)	($2,141,230)	[redacted]		$0
		Demand	MTR-DMD	DMD-MTR	($6,616,403)	($2,585,685)	($392,214)	($3,475,274)	($163,230)	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-371	Install on Cust Premise - Accum Res	Total			($8,345,814)	$0	$0	$0	$0	$0	[redacted]		($8,345,814)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DMD	DMD-LTG	($8,345,814)	$0	$0	$0	$0	$0	[redacted]		($8,345,814)
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
108-373	St Lt & Signal Sys - Accum Res	Total			($86,922,368)	$0	$0	$0	$0	$0	[redacted]	[redacted]	($86,922,368)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DMD	DMD-LTG	($86,922,368)	$0	$0	$0	$0	$0	[redacted]	[redacted]	($86,922,368)
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-374	Asset Ret Costs - Accum Res	Total			($28,356)	($16,179)	($306)	($9,019)	($688)	($2,079)	[redacted]	[redacted]	($85)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	($15,090)	($9,574)	($152)	($4,176)	($303)	($883)	[redacted]	[redacted]	($1)
		Energy	AE-PRI-NRG	NRG-PRI	($13,267)	($6,605)	($154)	($4,843)	($385)	($1,196)	[redacted]	[redacted]	($84)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-389	Land & Land Rights - Accum Res	Total			($5,722)	($3,012)	($57)	($1,687)	($129)	($390)	[redacted]	[redacted]	($16)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($2,931)	($1,754)	($28)	($765)	($56)	($162)	[redacted]	[redacted]	($0)
		Energy	AE-ALL-NRG	NRG-All	($2,791)	($1,257)	($29)	($922)	($73)	($228)	[redacted]	[redacted]	($16)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-390	Struct & Impmnts - Accum Res	Total			($54,183,893)	($28,517,495)	($540,927)	($15,974,841)	($1,220,287)	($3,688,661)	[redacted]	[redacted]	($153,556)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($27,757,459)	($16,612,974)	($263,296)	($7,246,234)	($525,997)	($1,532,124)	[redacted]	[redacted]	($2,582)
		Energy	AE-ALL-NRG	NRG-All	($26,426,434)	($11,904,522)	($277,630)	($8,728,606)	($694,290)	($2,156,537)	[redacted]	[redacted]	($150,974)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-391	Office Furn & Equip - Accum Res	Total			($6,118,526)	($3,220,238)	($61,082)	($1,803,903)	($137,797)	($416,529)	[redacted]	[redacted]	($17,340)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($3,134,414)	($1,875,962)	($29,732)	($818,256)	($59,396)	($173,010)	[redacted]	[redacted]	($292)
		Energy	AE-ALL-NRG	NRG-All	($2,984,113)	($1,344,276)	($31,350)	($985,647)	($78,400)	($243,519)	[redacted]	[redacted]	($17,048)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-392	Transportation Equip - Accum Res	Total			($3,822,686)	($2,011,916)	($38,163)	($1,127,029)	($86,092)	($260,236)	[redacted]	[redacted]	($10,833)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($1,958,295)	($1,172,049)	($18,576)	($511,224)	($37,109)	($108,092)	[redacted]	[redacted]	($182)
		Energy	AE-ALL-NRG	NRG-All	($1,864,391)	($839,867)	($19,587)	($615,805)	($48,982)	($152,144)	[redacted]	[redacted]	($10,651)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-393	Stores Equip - Accum Res	Total			($1,257,964)	($662,078)	($12,558)	($370,881)	($28,331)	($85,638)	[redacted]	[redacted]	($3,565)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($644,433)	($385,696)	($6,113)	($168,233)	($12,212)	($35,571)	[redacted]	[redacted]	($60)
		Energy	AE-ALL-NRG	NRG-All	($613,531)	($276,382)	($6,446)	($202,648)	($16,119)	($50,067)	[redacted]	[redacted]	($3,505)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-394	Tools, Shop & Garage Equip - Accum Res	Total			($10,790,043)	($5,678,902)	($107,719)	($3,181,189)	($243,005)	($734,551)	[redacted]	[redacted]	($30,579)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($5,527,550)	($3,308,265)	($52,432)	($1,442,997)	($104,746)	($305,103)	[redacted]	[redacted]	($514)
		Energy	AE-ALL-NRG	NRG-All	($5,262,493)	($2,370,636)	($55,287)	($1,738,193)	($138,259)	($429,447)	[redacted]	[redacted]	($30,064)

Jersey Central Power & Light
Depreciation Reserve
Test Year July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
108-395	Laboratory Equip - Accum Res	Total			($448,981)	($236,303)	($4,482)	($132,371)	($10,112)	($30,565)	[redacted]		($1,272)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($230,005)	($137,659)	($2,182)	($60,044)	($4,359)	($12,696)	[redacted]		($21)
		Energy	AE-ALL-NRG	NRG-All	($218,976)	($98,644)	($2,301)	($72,327)	($5,753)	($17,870)	[redacted]		($1,251)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-396	Power Operated Equip - Accum Res	Total			($2,847,208)	($1,498,513)	($28,424)	($839,432)	($64,123)	($193,829)	[redacted]		($8,069)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($1,458,575)	($872,964)	($13,835)	($380,769)	($27,640)	($80,509)	[redacted]		($136)
		Energy	AE-ALL-NRG	NRG-All	($1,388,633)	($625,549)	($14,589)	($458,663)	($36,483)	($113,320)	[redacted]		($7,933)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-397	Communication Equip - Accum Res	Total			($4,859,396)	($2,557,546)	($48,512)	($1,432,678)	($109,439)	($330,812)	[redacted]		($13,771)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($2,489,383)	($1,489,908)	($23,613)	($649,867)	($47,173)	($137,406)	[redacted]		($232)
		Energy	AE-ALL-NRG	NRG-All	($2,370,013)	($1,067,638)	($24,899)	($782,811)	($62,266)	($193,406)	[redacted]		($13,540)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-398	MISC Equip - Accum Res	Total			($921,377)	($484,929)	($9,198)	($271,646)	($20,751)	($62,724)	[redacted]		($2,611)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($472,005)	($282,497)	($4,477)	($123,219)	($8,944)	($26,053)	[redacted]		($44)
		Energy	AE-ALL-NRG	NRG-All	($449,372)	($202,432)	($4,721)	($148,427)	($11,806)	($36,671)	[redacted]		($2,567)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-399	Other Tangible Property - Accum Res	Total			($614,344)	($323,335)	($6,133)	($181,125)	($13,836)	($41,823)	[redacted]		($1,741)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($314,718)	($188,360)	($2,985)	($82,159)	($5,964)	($17,371)	[redacted]		($29)
		Energy	AE-ALL-NRG	NRG-All	($299,627)	($134,975)	($3,148)	($98,966)	($7,872)	($24,451)	[redacted]		($1,712)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
SRVCO-PIS	Service Company PIS - Accum Res	Total			($68,833,640)	($36,227,796)	($687,178)	($20,293,973)	($1,550,217)	($4,685,967)	[redacted]		($195,073)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($35,262,267)	($21,104,638)	($334,484)	($9,205,405)	($668,211)	($1,946,365)	[redacted]		($3,280)
		Energy	AE-ALL-NRG	NRG-All	($33,571,373)	($15,123,158)	($352,694)	($11,088,567)	($882,006)	($2,739,602)	[redacted]		($191,792)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108 - Intngbl	Intangible PIS - Accum Res	Total			($86,519,616)	($45,536,092)	($863,740)	($25,508,265)	($1,948,527)	($5,889,970)	[redacted]		($245,194)
		Customer			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			($44,322,483)	($26,527,221)	($420,426)	($11,570,623)	($839,900)	($2,446,460)	[redacted]		($4,123)
		Energy			($42,197,133)	($19,008,871)	($443,314)	($13,937,641)	($1,108,627)	($3,443,510)	[redacted]		($241,071)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108 - Gen	General PIS - Accum Res	Total			($154,703,781)	($81,422,063)	($1,544,433)	($45,610,755)	($3,484,117)	($10,531,723)	[redacted]		($438,426)
		Customer			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			($79,252,036)	($47,432,728)	($751,753)	($20,689,172)	($1,501,807)	($4,374,461)	[redacted]		($7,372)
		Energy			($75,451,745)	($33,989,335)	($792,680)	($24,921,583)	($1,982,310)	($6,157,262)	[redacted]		($431,054)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108 - Dist	Distribution PIS - Accum Res	Total			($1,554,542,233)	($908,539,364)	($16,927,517)	($455,128,536)	($33,545,387)	($38,545,023)	[redacted]		($99,128,071)
		Customer			($123,515,254)	($103,812,056)	($1,594,098)	($13,204,101)	($35,435)	($2,141,230)	[redacted]		$0
		Demand			($865,140,214)	($506,544,971)	($8,379,381)	($223,291,858)	($16,119,501)	($15,457,992)	[redacted]		($95,346,511)
		Energy			($565,886,764)	($298,182,337)	($6,954,038)	($218,632,577)	($17,390,451)	($20,945,801)	[redacted]		($3,781,560)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
TOTDPRRES	Total PIS - Accum Res	Total			($1,795,765,630)	($1,035,497,520)	($19,335,690)	($526,247,556)	($38,978,031)	($54,966,715)	[redacted]		($99,811,691)
		Customer			($123,515,254)	($103,812,056)	($1,594,098)	($13,204,101)	($35,435)	($2,141,230)	[redacted]		$0
		Demand			($988,714,733)	($580,504,920)	($9,551,560)	($255,551,653)	($18,461,208)	($22,278,913)	[redacted]		($95,358,006)
		Energy			($683,535,642)	($351,180,544)	($8,190,032)	($257,491,802)	($20,481,388)	($30,546,572)	[redacted]		($4,453,685)

REDACTED

Jersey Central Power & Light
Rate Base Additions & Deductions
Test Year: July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
RB-CUSTDEP	Acct 235 - Cust Deposits	Total			($47,386,955)	($41,437,530)	($639,339)	($5,277,139)	($8,279)	($17,777)	[redacted]	[redacted]	$0
		Customer	CUST	CUST-DEP	($47,386,955)	($41,437,530)	($639,339)	($5,277,139)	($8,279)	($17,777)	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-CAFC	Acct 252 - Cust Adv for Const	Total			($34,598,405)	($20,251,217)	($383,198)	($10,289,721)	($759,995)	($923,706)	[redacted]	[redacted]	($1,895,474)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($2,605,608)	($2,131,458)	($32,621)	($270,868)	($938)	($74,630)	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($18,992,618)	($11,273,603)	($190,915)	($4,999,130)	($359,779)	($360,539)	[redacted]	[redacted]	($1,808,651)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($13,000,179)	($6,846,156)	($159,662)	($5,019,723)	($399,278)	($488,536)	[redacted]	[redacted]	($86,823)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-ADIT	Accum Deferred Inc Tx	Total			($1,102,329,656)	($645,218,112)	($12,208,968)	($327,837,798)	($24,213,978)	($29,429,912)	[redacted]	[redacted]	($60,391,152)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($83,016,524)	($67,909,753)	($1,039,321)	($8,630,056)	($29,885)	($2,377,773)	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($605,118,232)	($359,184,979)	($6,082,698)	($159,275,812)	($11,462,803)	($11,487,038)	[redacted]	[redacted]	($57,624,902)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($414,194,900)	($218,123,381)	($5,086,949)	($159,931,930)	($12,721,290)	($15,565,101)	[redacted]	[redacted]	($2,766,249)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-REAQDBT	Unamort G/L on Reaquired Debt	Total			$2,178,358	$1,275,041	$24,127	$647,853	$47,850	$58,158	[redacted]	[redacted]	$119,341
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$164,052	$134,199	$2,054	$17,054	$59	$4,699	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$1,195,798	$709,800	$12,020	$314,751	$22,652	$22,700	[redacted]	[redacted]	$113,875
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$818,507	$431,042	$10,053	$316,048	$25,139	$30,759	[redacted]	[redacted]	$5,466
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-M&S	Materials & Supplies	Total			$22,844,588	$13,371,446	$253,018	$6,794,083	$501,808	$609,903	[redacted]	[redacted]	$1,251,541
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$1,720,428	$1,407,356	$21,539	$178,849	$619	$49,277	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$12,540,420	$7,443,720	$126,057	$3,300,819	$237,554	$238,056	[redacted]	[redacted]	$1,194,214
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$8,583,741	$4,520,371	$105,422	$3,314,416	$263,635	$322,570	[redacted]	[redacted]	$57,328
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-CWC	Cash Working Capital	Total			$114,525,841	$68,178,967	$1,511,343	$31,787,961	$2,171,180	$4,919,569	[redacted]	[redacted]	$3,701,186
		Customer	CWC-CUST	CWC-CUST	$23,893,092	$17,387,341	$261,927	$2,200,535	$15,710	$1,783,094	[redacted]	[redacted]	$0
		Demand	CWC-DMD	CWC-DMD	$52,843,062	$30,800,029	$786,421	$15,427,846	$1,044,280	$1,327,524	[redacted]	[redacted]	$3,456,962
		Energy	CWC-NRG	CWC-NRG	$37,789,687	$19,991,598	$462,995	$14,159,579	$1,111,190	$1,808,951	[redacted]	[redacted]	$244,224
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-EXCOR	Unamort Excess Cost of Removal	Total			($87,758,072)	($51,366,755)	($971,974)	($26,099,645)	($1,927,710)	($2,342,958)	[redacted]	[redacted]	($4,807,828)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($6,609,067)	($5,406,395)	($82,742)	($687,051)	($2,379)	($189,298)	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($48,174,345)	($28,595,240)	($484,252)	($12,680,180)	($912,570)	($914,500)	[redacted]	[redacted]	($4,587,603)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($32,974,660)	($17,365,121)	($404,979)	($12,732,414)	($1,012,760)	($1,239,160)	[redacted]	[redacted]	($220,225)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-REF	Customer Refunds	Total			($4,033,419)	($2,360,850)	($44,673)	($1,199,557)	($88,599)	($107,684)	[redacted]	[redacted]	($220,971)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($303,757)	($248,481)	($3,803)	($31,577)	($109)	($8,700)	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($2,214,125)	($1,314,256)	($22,257)	($582,789)	($41,942)	($42,031)	[redacted]	[redacted]	($210,849)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($1,515,537)	($798,112)	($18,613)	($585,190)	($46,547)	($56,953)	[redacted]	[redacted]	($10,122)

Jersey Central Power & Light
Rate Base Additions & Deductions
Test Year: July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
RB-OPRES	Net Operating Reserves	Total			($10,699,965)	($6,252,016)	($130,353)	($3,145,409)	($226,126)	($593,311)	[redacted]		($215,791)
		Customer	PAY-CUST	PAY-CUST	($1,319,416)	($950,195)	($14,314)	($120,256)	($859)	($97,444)			$0
		Demand	PAY-DMD	PAY-DMD	($5,244,206)	($3,178,122)	($66,689)	($1,495,299)	($104,405)	($210,323)			($189,368)
		Energy	PAY-NRG	PAY-NRG	($4,136,343)	($2,123,699)	($49,351)	($1,529,853)	($120,862)	($285,545)			($26,423)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-NOL	NOL- Net Operating Losses	Total			$22,826,438	$13,360,823	$252,817	$6,788,685	$501,410	$609,418			$1,250,547
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$1,719,061	$1,406,238	$21,522	$178,706	$619	$49,238			$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$12,530,456	$7,437,805	$125,957	$3,298,196	$237,365	$237,867			$1,193,265
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$8,576,921	$4,516,779	$105,338	$3,311,783	$263,425	$322,314			$57,282
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-CTA	CTA	Total			($20,787,390)	($12,069,614)	($228,424)	($6,177,995)	($457,539)	($623,492)			($1,052,821)
		Customer	RB-PLT-CUST	RB-PLT-CUST	($1,440,807)	($1,178,619)	($18,038)	($149,780)	($519)	($41,268)			$0
		Demand	RB-PLT-DMD	RB-PLT-DMD	($11,350,429)	($6,741,546)	($113,615)	($2,985,765)	($215,018)	($246,183)			($1,000,198)
		Energy	RB-PLT-NRG	RB-PLT-NRG	($7,996,154)	($4,149,449)	($96,771)	($3,042,450)	($242,002)	($336,041)			($52,623)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-PRAMT	Property-Related Unprotected Amort	Total			$32,052,681	$18,761,148	$355,003	$9,532,611	$704,075	$855,740			$1,756,007
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$2,413,890	$1,974,627	$30,221	$250,938	$869	$69,139			$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$17,595,155	$10,444,100	$176,868	$4,631,298	$333,306	$334,011			$1,675,572
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$12,043,636	$6,342,421	$147,914	$4,650,376	$369,900	$452,590			$80,435
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-ADD/DED	Rate Base Adds and Deducts	Total			($1,113,165,957)	($664,008,668)	($12,210,621)	($324,476,069)	($23,755,902)	($26,986,051)			($60,505,415)
		Customer			($112,771,613)	($96,952,670)	($1,492,915)	($12,340,646)	($25,092)	($851,444)			$0
		Demand			($594,389,062)	($353,452,292)	($5,733,102)	($155,046,064)	($11,221,359)	($11,100,455)			($57,787,684)
		Energy			($406,005,282)	($213,603,706)	($4,984,604)	($157,089,360)	($12,509,451)	($15,034,153)			($2,717,731)

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Jersey Central Power & Light
Rate Base Summary
Test Year: July 2019 - June 2020
Complied COSS

Account	Description	Category	Total	RS	RT	GS	GST	GP	GT	GT	LTG
RB-PIS	Rate Base Plant In Service	Total	$5,504,036,320	$3,195,622,926	$60,478,995	$1,635,788,750	$121,147,335	$165,185,636	[redacted]	[redacted]	$278,639,302
		Customer	$381,313,536	$311,924,744	$4,773,834	$39,639,785	$137,269	$10,921,646	[redacted]	[redacted]	$0
		Demand	$3,005,252,232	$1,784,964,634	$30,081,125	$790,538,048	$56,930,240	$65,226,449	[redacted]	[redacted]	$264,705,121
		Energy	$2,117,470,551	$1,098,733,547	$25,624,037	$805,610,918	$64,079,825	$89,037,542	[redacted]	[redacted]	$13,934,181
Account	Description	Category	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-ADD/DED	Rate Base Adds & Deducts	Total	($1,113,165,957)	($664,008,668)	($12,210,621)	($324,476,069)	($23,755,902)	($26,986,051)	[redacted]	[redacted]	($60,505,415)
		Customer	($112,771,613)	($96,952,670)	($1,492,915)	($12,340,646)	($25,092)	($851,444)	[redacted]	[redacted]	$0
		Demand	($594,389,062)	($353,452,292)	($5,733,102)	($155,046,064)	($11,221,359)	($11,100,455)	[redacted]	[redacted]	($57,787,684)
		Energy	($406,005,282)	($213,603,706)	($4,984,604)	($157,089,360)	($12,509,451)	($15,034,153)	[redacted]	[redacted]	($2,717,731)
Account	Description	Category	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTRBADJ	Total Rate Base Adjustments	Total	$3,819,060	$2,292,670	($19,886)	$1,329,052	$130,676	($1,513,180)	[redacted]	[redacted]	$2,153,873
		Customer	($2,408,809)	($1,292,570)	($18,584)	($161,659)	($2,881)	($382,172)	[redacted]	[redacted]	$0
		Demand	$5,401,270	$2,863,375	($19,067)	$818,207	$75,730	($479,019)	[redacted]	[redacted]	$2,142,044
		Energy	$826,599	$721,865	$17,765	$672,505	$57,827	($651,989)	[redacted]	[redacted]	$11,829
Account	Description	Category	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTDPRRES	Total PIS - Accum Res	Total	($1,795,765,630)	($1,035,497,520)	($19,335,690)	($526,247,556)	($38,978,031)	($54,966,715)	[redacted]	[redacted]	($99,811,691)
		Customer	($123,515,254)	($103,812,056)	($1,594,098)	($13,204,101)	($35,435)	($2,141,230)	[redacted]	[redacted]	$0
		Demand	($988,714,733)	($580,504,920)	($9,551,560)	($255,551,653)	($18,461,208)	($22,278,913)	[redacted]	[redacted]	($95,358,006)
		Energy	($683,535,642)	($351,180,544)	($8,190,032)	($257,491,802)	($20,481,388)	($30,546,572)	[redacted]	[redacted]	($4,453,685)
Sub-Total	Description	Category	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-TOT	Total Distribution Rate Base	Total	$2,598,923,793	$1,498,409,408	$28,912,798	$786,394,177	$58,544,078	$81,719,689	[redacted]	[redacted]	$120,476,069
		Customer	$142,617,859	$109,867,448	$1,668,237	$13,933,379	$73,862	$7,546,800	[redacted]	[redacted]	$0
		Demand	$1,427,549,708	$853,870,797	$14,777,396	$380,758,536	$27,323,403	$31,368,062	[redacted]	[redacted]	$113,701,475
		Energy	$1,028,756,227	$534,671,162	$12,467,165	$391,702,262	$31,146,813	$42,804,828	[redacted]	[redacted]	$6,774,594

Jersey Central Power & Light
Interest Expense
Test Year: July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
INTEXP	Interest Expense	Total			$62,352,756	$35,949,479	$693,669	$18,866,980	$1,404,575	$1,960,599	[redacted]		$2,890,433
		Customer	RB-CUST	RB-CUST	$3,421,653	$2,635,913	$40,024	$334,286	$1,772	$181,061			$0
		Demand	RB-DMD	RB-DMD	$34,249,430	$20,485,863	$354,536	$9,135,067	$655,537	$752,575			$2,727,899
		Energy	RB-NRG	RB-NRG	$24,681,672	$12,827,702	$299,109	$9,397,627	$747,267	$1,026,963			$162,534

Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
TOTINTEXP	Total Interest Expense	Total			$62,352,756	$35,949,479	$693,669	$18,866,980	$1,404,575	$1,960,599	[redacted]		$2,890,433
		Customer			$3,421,653	$2,635,913	$40,024	$334,286	$1,772	$181,061			$0
		Demand			$34,249,430	$20,485,863	$354,536	$9,135,067	$655,537	$752,575			$2,727,899
		Energy			$24,681,672	$12,827,702	$299,109	$9,397,627	$747,267	$1,026,963			$162,534

Jersey Central Power & Light
Income Tax Expenses
Test Year July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
PRETXNI	Pre-Tax Net Income	Total			($640,724)	($25,144,116)	$197,495	$19,737,457	($682,390)	($806,835)	[redacted]	[redacted]	$168,290
		Customer	RB-CUST	RB-CUST	($4,134,481)	($3,239,395)	$369,757	$4,960,521	$67,300	($2,696,309)	[redacted]	[redacted]	$0
		Demand	RB-DMD	RB-DMD	($124,360,931)	($163,124,233)	($3,060,305)	$20,903,714	$3,382,903	$10,041,757	[redacted]	[redacted]	($3,425,484)
		Energy	RB-NRG	RB-NRG	$127,854,688	$141,219,512	$2,888,043	($6,126,778)	($4,132,593)	($8,152,283)	[redacted]	[redacted]	$3,593,773
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
STTXEXP	State Tax Expense	Total			($57,665)	($2,262,970)	$17,775	$1,776,371	($61,415)	($72,615)	[redacted]	[redacted]	$15,146
		Customer	RB-CUST	RB-CUST	($372,103)	($291,546)	$33,278	$446,447	$6,057	($242,668)	[redacted]	[redacted]	$0
		Demand	RB-DMD	RB-DMD	($11,192,484)	($14,681,181)	($275,427)	$1,881,334	$304,461	$903,758	[redacted]	[redacted]	($308,294)
		Energy	RB-NRG	RB-NRG	$11,506,922	$12,709,756	$259,924	($551,410)	($371,933)	($733,705)	[redacted]	[redacted]	$323,440
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
FEDTXEXP	Federal Tax Expense	Total			($122,442)	($4,805,041)	$37,741	$3,771,828	($130,405)	($154,186)	[redacted]	[redacted]	$32,160
		Customer	RB-CUST	RB-CUST	($790,099)	($619,048)	$70,661	$947,955	$12,861	($515,265)	[redacted]	[redacted]	$0
		Demand	RB-DMD	RB-DMD	($23,765,374)	($31,173,041)	($584,824)	$3,994,700	$646,473	$1,918,980	[redacted]	[redacted]	($654,610)
		Energy	RB-NRG	RB-NRG	$24,433,031	$26,987,049	$551,905	($1,170,827)	($789,739)	($1,557,901)	[redacted]	[redacted]	$686,770
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
FEDITC	Amortization of Fed Income Tax Credit	Total			($97,625)	($56,286)	($1,086)	($29,540)	($2,199)	($3,070)	[redacted]	[redacted]	($4,526)
		Customer	RB-CUST	RB-CUST	($5,357)	($4,127)	($63)	($523)	($3)	($283)	[redacted]	[redacted]	$0
		Demand	RB-DMD	RB-DMD	($53,624)	($32,074)	($555)	($14,303)	($1,026)	($1,178)	[redacted]	[redacted]	($4,271)
		Energy	RB-NRG	RB-NRG	($38,644)	($20,084)	($468)	($14,714)	($1,170)	($1,608)	[redacted]	[redacted]	($254)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
FEDTAXRFM	Federal Tax Reform Amortization	Total			(5,291,287)	($3,050,691)	($58,865)	($1,601,062)	($119,193)	($166,377)	[redacted]	[redacted]	($245,284)
		Customer	RB-CUST	RB-CUST	($290,363)	($223,685)	($3,396)	($28,368)	($150)	($15,365)	[redacted]	[redacted]	$0
		Demand	RB-DMD	RB-DMD	($2,906,424)	($1,738,441)	($30,086)	($775,206)	($55,629)	($63,864)	[redacted]	[redacted]	($231,491)
		Energy	RB-NRG	RB-NRG	($2,094,499)	($1,088,565)	($25,383)	($797,487)	($63,413)	($87,149)	[redacted]	[redacted]	($13,793)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTITEXP	Total Income Tax Expense	Total			($5,569,019)	($10,174,988)	($4,435)	$3,917,598	($313,212)	($396,248)	[redacted]	[redacted]	($202,503)
		Customer			($1,457,923)	($1,138,406)	$100,480	$1,365,511	$18,765	($773,581)	[redacted]	[redacted]	$0
		Demand			($37,917,906)	($47,624,737)	($890,893)	$5,086,525	$894,278	$2,757,696	[redacted]	[redacted]	($1,198,665)
		Energy			$33,806,810	$38,588,155	$785,978	($2,534,438)	($1,226,255)	($2,380,363)	[redacted]	[redacted]	$996,162

Jersey Central Power & Light
Income Statement Summary
Test Year: July 2019 - June 2020
Complied COSS

		Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
Operating Revenues										
Distribution Revenues		$542,868,768	$283,576,706	$6,369,034	$179,570,595	$11,123,447	$25,384,277	[redacted]		$17,833,311
	Customer	$41,918,982	$30,980,844	$886,940	$9,291,578	$94,289	$250,047	[redacted]		$0
	Demand	$150,980,629	$0	$0	$95,229,974	$8,719,365	$19,685,757	[redacted]		$12,839,173
	Energy	$349,969,157	$252,595,861	$5,482,095	$75,049,042	$2,309,794	$5,448,473	[redacted]		$4,994,139
Other Operating Revenues		$15,543,099	$9,568,552	$180,074	$4,518,806	$262,379	$423,651	[redacted]		$710,851
	Customer	$488,146	$399,317	$6,111	$50,746	$176	$13,982	[redacted]		$0
	Demand	$12,619,441	$7,886,646	$144,051	$3,527,643	$187,401	$318,145	[redacted]		$694,585
	Energy	$2,435,511	$1,282,589	$29,912	$940,417	$74,803	$91,525	[redacted]		$16,266
Adjustments to Revenues		($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)	[redacted]		($9,867)
	Customer	$0	$0	$0	$0	$0	$0	[redacted]		$0
	Demand	($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)	[redacted]		($9,867)
	Energy	$0	$0	$0	$0	$0	$0	[redacted]		$0
Total Operating Revenues		$558,143,786	$293,020,676	$6,545,769	$183,990,642	$11,379,828	$25,793,163	[redacted]		$18,534,295
	Customer	$42,407,129	$31,380,161	$893,051	$9,342,324	$94,464	$264,029	[redacted]		$0
	Demand	$163,331,988	$7,762,064	$140,711	$98,658,859	$8,900,767	$19,989,136	[redacted]		$13,523,891
	Energy	$352,404,669	$253,878,451	$5,512,007	$75,989,460	$2,384,596	$5,539,998	[redacted]		$5,010,405
Operations & Maintenance Expenses								[redacted]		
Production O&M Expense		$0	$0	$0	$0	$0	$0	[redacted]		$0
	Customer	$0	$0	$0	$0	$0	$0	[redacted]		$0
	Demand	$0	$0	$0	$0	$0	$0	[redacted]		$0
	Energy	$0	$0	$0	$0	$0	$0	[redacted]		$0
Distribution O&M Expense		$93,816,859	$53,855,810	$1,065,504	$28,720,651	$2,139,446	$3,243,415	[redacted]		$4,329,213
	Customer	$4,872,763	$3,541,900	$53,356	$448,261	$3,200	$363,226	[redacted]		$0
	Demand	$51,109,965	$30,518,507	$550,491	$13,758,050	$981,748	$1,223,003	[redacted]		$4,078,167
	Energy	$37,834,131	$19,795,403	$461,657	$14,514,340	$1,154,498	$1,657,186	[redacted]		$251,046
Customer Accounts Expense		$30,283,331	$20,272,286	$598,439	$5,275,426	$154,613	$1,750,122	[redacted]		$4,540
	Customer	$23,317,839	$16,949,201	$255,327	$2,145,085	$15,314	$1,738,162	[redacted]		$0
	Demand	$5,370,924	$2,098,953	$318,383	$2,821,084	$132,504	$0	[redacted]		$0
	Energy	$1,594,568	$1,224,131	$24,729	$309,257	$6,795	$11,960	[redacted]		$4,540

Jersey Central Power & Light
Income Statement Summary
Test Year: July 2019 - June 2020
Complied COSS

	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
Customer Service Expense	$10,968,363	$6,258,055	$118,273	$3,488,479	$266,249	$804,331	[redacted]	[redacted]	$32,974
Customer	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Demand	$5,836,742	$3,703,353	$58,694	$1,615,326	$117,255	$341,540	[redacted]	[redacted]	$576
Energy	$5,131,620	$2,554,703	$59,579	$1,873,153	$148,994	$462,791	[redacted]	[redacted]	$32,399
Sales Expense	$56,383	$32,170	$608	$17,933	$1,369	$4,135	[redacted]	[redacted]	$170
Customer	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Demand	$30,004	$19,037	$302	$8,304	$603	$1,756	[redacted]	[redacted]	$3
Energy	$26,379	$13,133	$306	$9,629	$766	$2,379	[redacted]	[redacted]	$167
A&G Expense	$95,621,463	$54,407,366	$1,028,264	$30,328,743	$2,314,762	$6,992,836	[redacted]	[redacted]	$286,679
Customer	$262,814	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Demand	$50,744,481	$32,196,847	$510,282	$14,043,597	$1,019,411	$2,969,339	[redacted]	[redacted]	$5,004
Energy	$44,614,168	$22,210,518	$517,981	$16,285,146	$1,295,351	$4,023,497	[redacted]	[redacted]	$281,675
Adjustments to Expenses	($3,373,977)	($1,718,655)	($53,732)	($933,484)	($59,358)	($301,572)	[redacted]	[redacted]	($250,276)
Customer	($722,720)	($351,250)	($5,259)	($47,878)	($1,067)	($134,981)	[redacted]	[redacted]	$0
Demand	($1,629,092)	($735,337)	($34,301)	($546,729)	($35,362)	($78,650)	[redacted]	[redacted]	($241,570)
Energy	($1,022,165)	($632,068)	($14,172)	($338,878)	($22,930)	($87,942)	[redacted]	[redacted]	($8,705)
Total O&M Expenses	$227,372,423	$133,107,032	$2,757,355	$66,897,747	$4,817,081	$12,493,267	[redacted]	[redacted]	$4,403,300
Customer	$27,730,697	$20,139,851	$303,424	$2,545,468	$17,447	$1,966,408	[redacted]	[redacted]	$0
Demand	$111,463,024	$67,801,361	$1,403,851	$31,699,631	$2,216,159	$4,456,988	[redacted]	[redacted]	$3,842,179
Energy	$88,178,701	$45,165,820	$1,050,081	$32,652,648	$2,583,475	$6,069,871	[redacted]	[redacted]	$561,121
Depreciation Expense							[redacted]	[redacted]	
Depreciation Expense	$119,867,916	$68,210,072	$1,348,256	$34,483,801	$2,518,215	$3,589,672	[redacted]	[redacted]	$8,395,044
Customer	$11,539,239	$8,856,163	$134,421	$1,123,026	$6,053	$624,211	[redacted]	[redacted]	$0
Demand	$64,533,237	$36,503,327	$680,927	$16,606,323	$1,179,481	$1,254,802	[redacted]	[redacted]	$8,105,252
Energy	$43,795,440	$22,850,582	$532,908	$16,754,452	$1,332,681	$1,710,660	[redacted]	[redacted]	$289,792
Ajustments to Depreciation	$25,777,280	$14,795,188	$288,597	$7,491,380	$548,997	$746,644	[redacted]	[redacted]	$1,686,546
Customer	$2,318,258	$1,808,871	$27,516	$229,509	$1,120	$110,476	[redacted]	[redacted]	$0
Demand	$13,960,072	$8,015,941	$145,165	$3,617,503	$257,997	$269,472	[redacted]	[redacted]	$1,623,512
Energy	$9,498,949	$4,970,376	$115,916	$3,644,368	$289,880	$366,697	[redacted]	[redacted]	$63,035
Total Depreciation Expense	$145,645,195	$83,005,261	$1,636,854	$41,975,181	$3,067,212	$4,336,316	[redacted]	[redacted]	$10,081,590
Customer	$13,857,497	$10,665,034	$161,937	$1,352,536	$7,172	$734,687	[redacted]	[redacted]	$0
Demand	$78,493,309	$44,519,268	$826,092	$20,223,826	$1,437,478	$1,524,273	[redacted]	[redacted]	$9,728,763
Energy	$53,294,389	$27,820,959	$648,825	$20,398,820	$1,622,561	$2,077,356	[redacted]	[redacted]	$352,826

REDACTED

Jersey Central Power & Light
Income Statement Summary
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		Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
Amortization Expense								[redacted]		
Amortization Expense		$31,325,803	$16,814,642	$319,005	$9,254,212	$702,745	$1,898,546			$384,744
	Customer	$428,589	$350,598	$5,366	$44,554	$154	$12,276			$0
	Demand	$16,200,463	$9,680,664	$155,441	$4,235,963	$306,974	$781,081			$298,716
	Energy	$14,696,751	$6,783,380	$158,198	$4,973,694	$395,617	$1,105,189			$86,027
Adjustments to Amortization		$82,185,866	$43,520,510	$826,647	$24,332,125	$1,857,004	$5,487,830			$255,786
	Customer	$148,632	$107,254	$1,616	$13,575	$96	$10,877			$0
	Demand	$42,157,381	$25,323,202	$403,165	$11,057,629	$802,201	$2,276,383			$26,423
	Energy	$39,879,854	$18,090,054	$421,866	$13,260,921	$1,054,707	$3,200,569			$229,362
Total Amortization Expense		$113,511,669	$60,335,152	$1,145,652	$33,586,336	$2,559,749	$7,386,375			$640,529
	Customer	$577,221	$457,852	$6,982	$58,129	$250	$23,153			$0
	Demand	$58,357,843	$35,003,866	$558,606	$15,293,592	$1,109,175	$3,057,464			$325,140
	Energy	$54,576,604	$24,873,434	$580,064	$18,234,615	$1,450,324	$4,305,758			$315,389
Taxes Other Than Income										
Taxes Other Than Income		$9,557,328	$5,566,203	$110,539	$2,825,481	$206,307	$404,302			$343,193
	Customer	$911,982	$690,257	$10,465	$87,505	$494	$51,885			$0
	Demand	$4,960,155	$2,973,425	$55,781	$1,354,796	$96,149	$149,295			$319,286
	Energy	$3,685,191	$1,902,521	$44,293	$1,383,180	$109,664	$203,121			$23,908
Adjustments to Taxes Other		$345,139	$201,665	$4,205	$101,459	$7,294	$19,138			$6,961
	Customer	$42,559	$30,650	$462	$3,879	$28	$3,143			$0
	Demand	$169,157	$102,514	$2,151	$48,232	$3,368	$6,784			$6,108
	Energy	$133,422	$68,502	$1,592	$49,347	$3,899	$9,211			$852
Total Taxes Other Than Income		$9,902,467	$5,767,869	$114,744	$2,926,939	$213,601	$423,440			$350,154
	Customer	$954,541	$720,906	$10,927	$91,384	$522	$55,029			$0
	Demand	$5,129,312	$3,075,939	$57,932	$1,403,029	$99,517	$156,080			$325,394
	Energy	$3,818,614	$1,971,024	$45,885	$1,432,527	$113,563	$212,332			$24,760
Income Taxes										
State Income Taxes		($57,665)	($2,262,970)	$17,775	$1,776,371	($61,415)	($72,615)			$15,146
	Customer	($372,103)	($291,546)	$33,278	$446,447	$6,057	($242,668)			$0
	Demand	($11,192,484)	($14,681,181)	($275,427)	$1,881,334	$304,461	$903,758			($308,294)
	Energy	$11,506,922	$12,709,756	$259,924	($551,410)	($371,933)	($733,705)			$323,440

REDACTED

Jersey Central Power & Light
Income Statement Summary
Test Year: July 2019 - June 2020
Complied COSS

		Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
Federal Income Taxes		($122,442)	($4,805,041)	$37,741	$3,771,828	($130,405)	($154,186)	[redacted]		$32,160
	Customer	($790,099)	($619,048)	$70,661	$947,955	$12,861	($515,265)	[redacted]		$0
	Demand	($23,765,374)	($31,173,041)	($584,824)	$3,994,700	$646,473	$1,918,980	[redacted]		($654,610)
	Energy	$24,433,031	$26,987,049	$551,905	($1,170,827)	($789,739)	($1,557,901)	[redacted]		$686,770
Investment Tax Credit		($97,625)	($56,286)	($1,086)	($29,540)	($2,199)	($3,070)	[redacted]		($4,526)
	Customer	($5,357)	($4,127)	($63)	($523)	($3)	($283)	[redacted]		$0
	Demand	($53,624)	($32,074)	($555)	($14,303)	($1,026)	($1,178)	[redacted]		($4,271)
	Energy	($38,644)	($20,084)	($468)	($14,714)	($1,170)	($1,608)	[redacted]		($254)
Federal Tax Reform		($5,291,287)	($3,050,691)	($58,865)	($1,601,062)	($119,193)	($166,377)	[redacted]		($245,284)
	Customer	($290,363)	($223,685)	($3,396)	($28,368)	($150)	($15,365)	[redacted]		$0
	Demand	($2,906,424)	($1,738,441)	($30,086)	($775,206)	($55,629)	($63,864)	[redacted]		($231,491)
	Energy	($2,094,499)	($1,088,565)	($25,383)	($797,487)	($63,413)	($87,149)	[redacted]		($13,793)
Total Income Taxes		($5,569,019)	($10,174,988)	($4,435)	$3,917,598	($313,212)	($396,248)	[redacted]		($202,503)
	Customer	($1,457,923)	($1,138,406)	$100,480	$1,365,511	$18,765	($773,581)	[redacted]		$0
	Demand	($37,917,906)	($47,624,737)	($890,893)	$5,086,525	$894,278	$2,757,696	[redacted]		($1,198,665)
	Energy	$33,806,810	$38,588,155	$785,978	($2,534,438)	($1,226,255)	($2,380,363)	[redacted]		$996,162
Net Operating Income		$67,281,051	$20,980,350	$895,599	$34,686,840	$1,035,397	$1,550,013	[redacted]		$3,261,225
	Customer	$745,096	$534,924	$309,301	$3,929,296	$50,307	($1,741,667)	[redacted]		$0
	Demand	($52,193,595)	($95,013,633)	($1,814,876)	$24,952,257	$3,144,161	$8,036,636	[redacted]		$501,080
	Energy	$118,729,551	$115,459,059	$2,401,174	$5,805,287	($2,159,071)	($4,744,956)	[redacted]		$2,760,145
Interest Expense		$62,352,756	$35,949,479	$693,669	$18,866,980	$1,404,575	$1,960,599	[redacted]		$2,890,433
	Customer	$3,421,653	$2,635,913	$40,024	$334,286	$1,772	$181,061	[redacted]		$0
	Demand	$34,249,430	$20,485,863	$354,536	$9,135,067	$655,537	$752,575	[redacted]		$2,727,899
	Energy	$24,681,672	$12,827,702	$299,109	$9,397,627	$747,267	$1,026,963	[redacted]		$162,534
Net Income		$4,928,295	($14,969,128)	$201,930	$15,819,859	($369,178)	($410,586)	[redacted]		$370,792
	Customer	($2,676,558)	($2,100,989)	$269,277	$3,595,009	$48,535	($1,922,728)	[redacted]		$0
	Demand	($86,443,025)	($115,499,496)	($2,169,412)	$15,817,189	$2,488,624	$7,284,061	[redacted]		($2,226,819)
	Energy	$94,047,878	$102,631,356	$2,102,065	($3,592,339)	($2,906,338)	($5,771,919)	[redacted]		$2,597,611
Rate Base		$2,598,923,793	$1,498,409,408	$28,912,798	$786,394,177	$58,544,078	$81,719,689	[redacted]		$120,476,069
Rate of Return		2 59%	1.40%	3.10%	4.41%	1.77%	1.90%	[redacted]		2.71%

Jersey Central Power & Light
Adjustments
Test Year: July 2019 - June 2020
Complied COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-1	Revenue Normalization	Total			($319,110)	($166,693)	($3,744)	($105,555)	($6,539)	($14,921)	[redacted]		($10,483)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DMD	REV-ALL	($319,110)	($166,693)	($3,744)	($105,555)	($6,539)	($14,921)	[redacted]		($10,483)
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-2	Tariff Fee Adjustments	Total			$51,028	$42,111	$404	$6,797	$540	$156	[redacted]		$616
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DMD	ALL451	$51,028	$42,111	$404	$6,797	$540	$156	[redacted]		$616
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-3	Int on Cust Deposits	Total			$1,104,116	$965,494	$14,897	$122,957	$193	$414	[redacted]		$0
		Customer	CUST	CUST-DEP	$1,104,116	$965,494	$14,897	$122,957	$193	$414	[redacted]		$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-4	Annualize Payroll Increase	Total			$4,511,619	$2,636,150	$54,963	$1,326,255	$95,346	$250,168	[redacted]		$90,988
		Customer	PAY-CUST	PAY-CUST	$556,329	$400,648	$6,035	$50,706	$362	$41,087	[redacted]		$0
		Demand	PAY-DMD	PAY-DMD	$2,211,209	$1,340,049	$28,119	$630,490	$44,022	$88,682	[redacted]		$79,847
		Energy	PAY-NRG	PAY-NRG	$1,744,081	$895,453	$20,809	$645,060	$50,961	$120,399	[redacted]		$11,141
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-4a	Svngs Pln Match on Payroll Inc	Total			$135,349	$79,085	$1,649	$39,788	$2,860	$7,505	[redacted]		$2,730
		Customer	PAY-CUST	PAY-CUST	$16,690	$12,019	$181	$1,521	$11	$1,233	[redacted]		$0
		Demand	PAY-DMD	PAY-DMD	$66,336	$40,202	$844	$18,915	$1,321	$2,660	[redacted]		$2,395
		Energy	PAY-NRG	PAY-NRG	$52,323	$26,864	$624	$19,352	$1,529	$3,612	[redacted]		$334
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-4b	FICA on Payroll Increase	Total			$345,139	$201,665	$4,205	$101,459	$7,294	$19,138	[redacted]		$6,961
		Customer	PAY-CUST	PAY-CUST	$42,559	$30,650	$462	$3,879	$28	$3,143	[redacted]		$0
		Demand	PAY-DMD	PAY-DMD	$169,157	$102,514	$2,151	$48,232	$3,368	$6,784	[redacted]		$6,108
		Energy	PAY-NRG	PAY-NRG	$133,422	$68,502	$1,592	$49,347	$3,899	$9,211	[redacted]		$852
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-5	Reclass G/L on Reaquired Debt	Total			$638,187	$373,545	$7,068	$189,800	$14,019	$17,038	[redacted]		$34,963
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$48,062	$39,316	$602	$4,996	$17	$1,377	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$350,329	$207,948	$3,522	$92,212	$6,636	$6,650	[redacted]		$33,362
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$239,796	$126,281	$2,945	$92,592	$7,365	$9,011	[redacted]		$1,602
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-6	BPU & RPA Assessments	Total			($425,441)	($222,236)	($4,991)	($140,728)	($8,717)	($19,893)	[redacted]		($13,976)
		Customer	DIST-REV-CUST	DIST-REV-CUST	($32,852)	($24,279)	($695)	($7,282)	($74)	($196)	[redacted]		$0
		Demand	DIST-REV-DMD	DIST-REV-DMD	($118,322)	$0	$0	($74,631)	($6,833)	($15,428)	[redacted]		($10,062)
		Energy	DIST-REV-NRG	DIST-REV-NRG	($274,267)	($197,957)	($4,296)	($58,815)	($1,810)	($4,270)	[redacted]		($3,914)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-7	Return Net Gain on Sale of Property	Total			($101,996)	($59,701)	($1,130)	($30,334)	($2,240)	($2,723)	[redacted]		($5,588)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($7,681)	($6,284)	($96)	($799)	($3)	($220)	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($55,990)	($33,235)	($563)	($14,737)	($1,061)	($1,063)	[redacted]		($5,332)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($38,324)	($20,182)	($471)	($14,798)	($1,177)	($1,440)	[redacted]		($256)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-8	Rate Case Exp	Total			$156,039	$82,125	$1,558	$46,004	$3,514	$10,623	[redacted]		$442
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$79,936	$47,842	$758	$20,868	$1,515	$4,412	[redacted]		$7
		Energy	AE-ALL-NRG	NRG-ALL	$76,103	$34,283	$800	$25,137	$1,999	$6,210	[redacted]		$435

Jersey Central Power & Light
Adjustments
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-9	OPEB Settlement	Total			$1,187,500	$693,859	$14,467	$349,083	$25,096	$65,847	[redacted]	[redacted]	$23,949
		Customer	PAY-CUST	PAY-CUST	$146,431	$105,454	$1,589	$13,346	$95	$10,814	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	$582,011	$352,713	$7,401	$165,951	$11,587	$23,342	[redacted]	[redacted]	$21,016
		Energy	PAY-NRG	PAY-NRG	$459,058	$235,692	$5,477	$169,786	$13,413	$31,690	[redacted]	[redacted]	$2,933

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-10a	Pension Smoothing	Total			($25,638,726)	($14,980,770)	($312,346)	($7,536,873)	($541,832)	($1,421,662)	[redacted]	[redacted]	($517,069)
		Customer	PAY-CUST	PAY-CUST	($3,161,520)	($2,276,810)	($34,298)	($288,152)	($2,057)	($233,490)	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	($12,565,907)	($7,615,259)	($159,796)	($3,582,962)	($250,171)	($503,964)	[redacted]	[redacted]	($453,754)
		Energy	PAY-NRG	PAY-NRG	($9,911,299)	($5,088,701)	($118,251)	($3,665,759)	($289,603)	($684,208)	[redacted]	[redacted]	($63,315)

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-10b	OPEB Smoothing	Total			$7,176,427	$4,193,204	$87,427	$2,109,614	$151,662	$397,931	[redacted]	[redacted]	$144,731
		Customer	PAY-CUST	PAY-CUST	$884,928	$637,292	$9,600	$80,655	$576	$65,355	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	$3,517,270	$2,131,555	$44,728	$1,002,892	$70,024	$141,063	[redacted]	[redacted]	$127,008
		Energy	PAY-NRG	PAY-NRG	$2,774,230	$1,424,357	$33,099	$1,026,067	$81,062	$191,514	[redacted]	[redacted]	$17,722

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-11	Normalize Forestry Maint Exp	Total			$5,808,721	$3,447,991	$65,071	$1,918,307	$146,360	$212,982	[redacted]	[redacted]	$18,010
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	OHL-PLT-DMD	OHL-PLT-DMD	$3,136,780	$2,053,005	$32,538	$895,478	$65,002	$90,438	[redacted]	[redacted]	$319
		Energy	OHL-PLT-NRG	OHL-PLT-NRG	$2,671,941	$1,394,986	$32,533	$1,022,828	$81,358	$122,545	[redacted]	[redacted]	$17,691

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-12	Amort Forestry Reg Asset	Total			$2,894,215	$1,717,973	$32,422	$955,803	$72,924	$106,119	[redacted]	[redacted]	$8,974
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	OHL-PLT-DMD	OHL-PLT-DMD	$1,562,911	$1,022,917	$16,212	$446,175	$32,387	$45,061	[redacted]	[redacted]	$159
		Energy	OHL-PLT-NRG	OHL-PLT-NRG	$1,331,304	$695,057	$16,210	$509,628	$40,537	$61,058	[redacted]	[redacted]	$8,815

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-13	Annualize Deprec Exp	Total			$17,988,446	$10,236,210	$202,331	$5,174,946	$377,906	$538,698	[redacted]	[redacted]	$1,259,835
		Customer	DPR-TOT-CUST	DPR-TOT-CUST	$1,731,681	$1,329,035	$20,172	$168,531	$908	$93,675	[redacted]	[redacted]	$0
		Demand	DPR-TOT-DMD	DPR-TOT-DMD	$9,684,432	$5,478,014	$102,186	$2,492,093	$177,003	$188,307	[redacted]	[redacted]	$1,216,346
		Energy	DPR-TOT-NRG	DPR-TOT-NRG	$6,572,333	$3,429,162	$79,973	$2,514,322	$199,994	$256,717	[redacted]	[redacted]	$43,489

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-14	Average Net Salvage	Total			$7,788,834	$4,558,978	$86,266	$2,316,434	$171,091	$207,946	[redacted]	[redacted]	$426,711
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$586,578	$479,836	$7,344	$60,978	$211	$16,801	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$4,275,641	$2,537,927	$42,979	$1,125,410	$80,994	$81,165	[redacted]	[redacted]	$407,166
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$2,926,616	$1,541,215	$35,943	$1,130,046	$89,886	$109,980	[redacted]	[redacted]	$19,546

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-15	Amort Storm Damage Exp	Total			$76,863,146	$40,453,801	$767,337	$22,661,283	$1,731,051	$5,232,589	[redacted]	[redacted]	$217,828
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$39,375,642	$23,566,513	$373,502	$10,279,224	$746,159	$2,173,410	[redacted]	[redacted]	$3,663
		Energy	AE-ALL-NRG	NRG-ALL	$37,487,503	$16,887,288	$393,836	$12,382,059	$984,893	$3,059,179	[redacted]	[redacted]	$214,165

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-16	ServCo Depr @ JCP&L Rates	Total			$1,710,308	$900,151	$17,074	$504,244	$38,518	$116,432	[redacted]	[redacted]	$4,847
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DPR-G&I-DMD	DMD-ALL	$876,161	$524,386	$8,311	$228,726	$16,603	$48,361	[redacted]	[redacted]	$82
		Energy	DPR-G&I-NRG	NRG-ALL	$834,147	$375,765	$8,763	$275,517	$21,915	$68,071	[redacted]	[redacted]	$4,765

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-17	SERP/EDCP	Total			($1,181,606)	($690,415)	($14,395)	($347,350)	($24,971)	($65,520)	[redacted]	[redacted]	($23,830)
		Customer	PAY-CUST	PAY-CUST	($145,704)	($104,931)	($1,581)	($13,280)	($95)	($10,761)	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	($579,122)	($350,963)	($7,364)	($165,127)	($11,530)	($23,226)	[redacted]	[redacted]	($20,912)
		Energy	PAY-NRG	PAY-NRG	($456,780)	($234,522)	($5,450)	($168,943)	($13,347)	($31,533)	[redacted]	[redacted]	($2,918)

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-18	Removal of Certain Advertising Expense	Total			($924,095)	($525,798)	($9,937)	($293,100)	($22,370)	($67,579)	[redacted]		($2,770)
		Customer	A&G-GT-CUST	CUST-GTA&G	($2,540)	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	($490,400)	($311,153)	($4,931)	($135,719)	($9,852)	($28,696)	[redacted]		($48)
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	($431,156)	($214,645)	($5,006)	($157,381)	($12,518)	($38,883)	[redacted]		($2,722)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-19	Holding Company Costs	Total			$147,821	$84,108	$1,590	$46,885	$3,578	$10,810	[redacted]		$443
		Customer	A&G-GT-CUST	CUST-GTA&G	$406	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$78,446	$49,773	$789	$21,710	$1,576	$4,590	[redacted]		$8
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$68,969	$34,335	$801	$25,175	$2,002	$6,220	[redacted]		$435
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-20	ARAM	Total			$131,215	$76,803	$1,453	$39,024	$2,882	$3,503	[redacted]		$7,189
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$9,882	$8,084	$124	$1,027	$4	$283	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$72,030	$42,755	$724	$18,959	$1,364	$1,367	[redacted]		$6,859
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$49,303	$25,964	$606	$19,037	$1,514	$1,853	[redacted]		$329
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-21	LED Amortization	Total			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-22	Production Related Regulatory Asset Amortization	Total			$1,211,786	$637,774	$12,097	$357,266	$27,291	$82,494	[redacted]		$3,434
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$620,777	$371,538	$5,888	$162,057	$11,764	$34,265	[redacted]		$58
		Energy	AE-ALL-NRG	NRG-ALL	$591,009	$266,237	$6,209	$195,209	$15,527	$48,229	[redacted]		$3,376
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-23	Service Company O&M	Total			$3,407,305	$1,938,712	$36,640	$1,080,712	$82,483	$249,178	[redacted]		$10,215
		Customer	A&G-GT-CUST	CUST-GTA&G	$9,365	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$1,808,192	$1,147,279	$18,183	$500,419	$36,325	$105,807	[redacted]		$178
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$1,589,749	$791,433	$18,457	$580,293	$46,158	$143,370	[redacted]		$10,037
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
PTYADDS	RB Post Test-Year Additions 6mo CAPEX	Total			$30,013,986	$17,567,855	$332,423	$8,926,294	$659,293	$801,311	[redacted]		$1,644,317
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$2,260,355	$1,849,032	$28,298	$234,977	$814	$64,741	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$16,476,024	$9,779,808	$165,618	$4,336,726	$312,107	$312,767	[redacted]		$1,568,998
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$11,277,606	$5,939,015	$138,506	$4,354,591	$346,372	$423,803	[redacted]		$75,319
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
PTYDPRRES	RB Post Test-Year Deprec Reserve 6mo CAPEX	Total			($663,309)	($388,250)	($7,347)	($197,271)	($14,570)	($17,709)	[redacted]		($36,339)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($49,954)	($40,864)	($625)	($5,193)	($18)	($1,431)	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($364,120)	($216,134)	($3,660)	($95,842)	($6,898)	($6,912)	[redacted]		($34,675)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($249,235)	($131,252)	($3,061)	($96,236)	($7,655)	($9,366)	[redacted]		($1,665)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-IIPADD	RB IIP Incremental Plant Additions	Total			$31,402,232	$18,380,426	$347,799	$9,339,165	$689,787	$838,374	[redacted]		$1,720,372
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$2,364,904	$1,934,555	$29,607	$245,846	$851	$67,736	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$17,238,095	$10,232,157	$173,279	$4,537,314	$326,543	$327,233	[redacted]		$1,641,569
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$11,799,233	$6,213,714	$144,913	$4,556,005	$362,393	$443,405	[redacted]		$78,803
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-IIPDEP	RB IIP Incremental Deprec Reserve	Total			(758,683)	($444,074)	($8,403)	($225,636)	($16,665)	($20,255)	[redacted]		($41,564)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($57,136)	($46,739)	($715)	($5,940)	($21)	($1,637)	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($416,475)	($247,210)	($4,186)	($109,622)	($7,889)	($7,906)	[redacted]		($39,661)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($285,071)	($150,124)	($3,501)	($110,074)	($8,755)	($10,713)	[redacted]		($1,904)

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
RB-P&OPEBADD	RB Delayed Recog Pension & OPEB Additions	Total			($68,892,010)	($40,253,770)	($839,283)	($20,251,800)	($1,455,917)	($3,820,047)	[redacted]		($1,389,379)
		Customer	PAY-CUST	PAY-CUST	($8,495,097)	($6,117,856)	($92,161)	($774,274)	($5,528)	($627,394)			$0
		Demand	PAY-DMD	PAY-DMD	($33,764,961)	($20,462,425)	($429,377)	($9,627,524)	($672,217)	($1,354,167)			($1,219,251)
		Energy	PAY-NRG	PAY-NRG	($26,631,952)	($13,673,490)	($317,745)	($9,850,002)	($778,172)	($1,838,486)			($170,128)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-P&OPEBDEP	RB Delayed Recog Pension & OPEB Deprec Reserve	Total			$12,716,844	$7,430,483	$154,924	$3,738,300	$268,749	$705,146			$256,467
		Customer	PAY-CUST	PAY-CUST	$1,568,118	$1,129,301	$17,012	$142,924	$1,020	$115,811			$0
		Demand	PAY-DMD	PAY-DMD	$6,232,707	$3,777,179	$79,259	$1,777,154	$124,085	$249,967			$225,063
		Energy	PAY-NRG	PAY-NRG	$4,916,018	$2,524,003	$58,653	$1,818,222	$143,644	$339,368			$31,404
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-REV	Adjs to Revenue	Total			($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)			($9,867)
		Customer			$0	$0	$0	$0	$0	$0			$0
		Demand			($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)			($9,867)
		Energy			$0	$0	$0	$0	$0	$0			$0
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-O&M	Adjs to O&M Exp	Total			($3,373,977)	($1,718,655)	($53,732)	($933,484)	($59,358)	($301,572)			($250,276)
		Customer			($722,720)	($351,250)	($5,259)	($47,878)	($1,067)	($134,981)			$0
		Demand			($1,629,092)	($735,337)	($34,301)	($546,729)	($35,362)	($78,650)			($241,570)
		Energy			($1,022,165)	($632,068)	($14,172)	($338,878)	($22,930)	($87,942)			($8,705)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-AMORT	Adjs to Amortization Exp	Total			$82,185,866	$43,520,510	$826,647	$24,332,125	$1,857,004	$5,487,830			$255,786
		Customer			$148,632	$107,254	$1,616	$13,575	$96	$10,877			$0
		Demand			$42,157,381	$25,323,202	$403,165	$11,057,629	$802,201	$2,276,383			$26,423
		Energy			$39,879,854	$18,090,054	$421,866	$13,260,921	$1,054,707	$3,200,569			$229,362
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-TXOTR	Adjs to Taxes Other Than Income	Total			$345,139	$201,665	$4,205	$101,459	$7,294	$19,138			$6,961
		Customer			$42,559	$30,650	$462	$3,879	$28	$3,143			$0
		Demand			$169,157	$102,514	$2,151	$48,232	$3,368	$6,784			$6,108
		Energy			$133,422	$68,502	$1,592	$49,347	$3,899	$9,211			$852
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-DEPRC	Adjs to Depreciation Exp	Total			$25,777,280	$14,795,188	$288,597	$7,491,380	$548,997	$746,644			$1,686,546
		Customer			$2,318,258	$1,808,871	$27,516	$229,509	$1,120	$110,476			$0
		Demand			$13,960,072	$8,015,941	$145,165	$3,617,503	$257,997	$269,472			$1,623,512
		Energy			$9,498,949	$4,970,376	$115,916	$3,644,368	$289,880	$366,697			$63,035
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
TOTEXPADJ	Total Adjustments to Expense	Total			$104,934,308	$56,798,709	$1,065,717	$30,991,479	$2,353,936	$5,952,039			$1,699,017
		Customer			$1,786,730	$1,595,524	$24,335	$199,086	$176	($10,485)			$0
		Demand			$54,657,518	$32,706,320	$516,180	$14,176,635	$1,028,204	$2,473,989			$1,414,473
		Energy			$48,490,060	$22,496,865	$525,202	$16,615,758	$1,325,556	$3,488,535			$284,544
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
TOTRBADJ	Total Rate Base Adjustments	Total			$3,819,060	$2,292,670	($19,886)	$1,329,052	$130,676	($1,513,180)			$2,153,873
		Customer			($2,408,809)	($1,292,570)	($18,584)	($161,659)	($2,881)	($382,172)			$0
		Demand			$5,401,270	$2,863,375	($19,067)	$818,207	$75,730	($479,019)			$2,142,044
		Energy			$826,599	$721,865	$17,765	$672,505	$57,827	($651,989)			$11,829

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AF	RS	RT	GS	GST	GP	GT	GT-D	LTG
ALL451	0.825	0.008	0.133	0.011	0.003	[redacted]	[redacted]	0.012
ALL901	0.793	0.016	0.183	0.002	0.001	[redacted]	[redacted]	0.003
ALL905	0.793	0.016	0.183	0.002	0.001	[redacted]	[redacted]	0.003
CUST-ALL	0.872	0.013	0.111	0.000	0.000	[redacted]	[redacted]	0.003
CUST-DEP	0.874	0.013	0.111	0.000	0.000	[redacted]	[redacted]	0.000
CUST-GTA&G	0.000	0.000	0.000	0.000	0.000	[redacted]	[redacted]	0.000
CUST-LTG	0.000	0.000	0.000	0.000	0.000	[redacted]	[redacted]	1.000
CUST-MTR	0.727	0.011	0.092	0.001	0.075	[redacted]	[redacted]	0.000
CUST-PRI	0.872	0.013	0.111	0.000	0.000	[redacted]	[redacted]	0.003
CUST-SEC	0.873	0.013	0.111	0.000	0.000	[redacted]	[redacted]	0.003
CUST-SVCS	0.875	0.013	0.111	0.000	0.000	[redacted]	[redacted]	0.000
CWC-CUST	0.728	0.011	0.092	0.001	0.075	[redacted]	[redacted]	0.000
CWC-DMD	0.583	0.015	0.292	0.020	0.025	[redacted]	[redacted]	0.065
CWC-NRG	0.529	0.012	0.375	0.029	0.048	[redacted]	[redacted]	0.006
DIST-PLT-CUST	0.818	0.013	0.104	0.000	0.029	[redacted]	[redacted]	0.000
DIST-PLT-DMD	0.594	0.010	0.263	0.019	0.019	[redacted]	[redacted]	0.095
DIST-PLT-NRG	0.527	0.012	0.386	0.031	0.038	[redacted]	[redacted]	0.007
DIST-REV-CUST	0.739	0.021	0.222	0.002	0.006	[redacted]	[redacted]	0.000
DIST-REV-DMD	0.000	0.000	0.631	0.058	0.130	[redacted]	[redacted]	0.085
DIST-REV-NRG	0.722	0.016	0.214	0.007	0.016	[redacted]	[redacted]	0.014
DMD-ALL	0.599	0.009	0.261	0.019	0.055	[redacted]	[redacted]	0.000
DMD-LTG	0.000	0.000	0.000	0.000	0.000	[redacted]	[redacted]	1.000
DMD-MTR	0.391	0.059	0.525	0.025	0.000	[redacted]	[redacted]	0.000
DMD-PRI	0.634	0.010	0.277	0.020	0.059	[redacted]	[redacted]	0.000
DMD-SEC	0.674	0.011	0.294	0.021	0.000	[redacted]	[redacted]	0.000
DPR-TOT-CUST	0.767	0.012	0.097	0.001	0.054	[redacted]	[redacted]	0.000
DPR-TOT-DMD	0.566	0.011	0.257	0.018	0.019	[redacted]	[redacted]	0.126
DPR-TOT-NRG	0.522	0.012	0.383	0.030	0.039	[redacted]	[redacted]	0.007
LATEPAY	0.000	0.000	0.816	0.029	0.104	[redacted]	[redacted]	0.131
NONE	0.000	0.000	0.000	0.000	0.000	[redacted]	[redacted]	0.000
NRG-ALL	0.450	0.011	0.330	0.026	0.082	[redacted]	[redacted]	0.006
NRG-PRI	0.498	0.012	0.365	0.029	0.090	[redacted]	[redacted]	0.006
NRG-SEC	0.547	0.013	0.401	0.032	0.000	[redacted]	[redacted]	0.007
OHL-PLT-DMD	0.654	0.010	0.285	0.021	0.029	[redacted]	[redacted]	0.000
OHL-PLT-NRG	0.522	0.012	0.383	0.030	0.046	[redacted]	[redacted]	0.007
PAY-CUST	0.720	0.011	0.091	0.001	0.074	[redacted]	[redacted]	0.000
PAY-DMD	0.606	0.013	0.285	0.020	0.040	[redacted]	[redacted]	0.036
PAY-NRG	0.513	0.012	0.370	0.029	0.069	[redacted]	[redacted]	0.006
PWRGD	0.917	0.041	0.042	0.000	0.000	[redacted]	[redacted]	0.000
RB-CUST	0.770	0.012	0.098	0.001	0.053	[redacted]	[redacted]	0.000
RB-DMD	0.598	0.010	0.267	0.019	0.022	[redacted]	[redacted]	0.080
RB-NRG	0.520	0.012	0.381	0.030	0.042	[redacted]	[redacted]	0.007
RB-PLT-CUST	0.818	0.013	0.104	0.000	0.029	[redacted]	[redacted]	0.000
RB-PLT-DMD	0.594	0.010	0.263	0.019	0.022	[redacted]	[redacted]	0.088
RB-PLT-NRG	0.519	0.012	0.380	0.030	0.042	[redacted]	[redacted]	0.007
REV-ALL	0.522	0.012	0.331	0.020	0.047	[redacted]	[redacted]	0.033
SRVC-CUST	0.802	0.012	0.186	0.001	0.000	[redacted]	[redacted]	0.000
SRVC-DMD	0.006	0.000	0.992	0.002	0.000	[redacted]	[redacted]	0.000
SSEQ-PLT-DMD	0.654	0.010	0.285	0.021	0.029	[redacted]	[redacted]	0.000
SSEQ-PLT-NRG	0.522	0.012	0.383	0.030	0.046	[redacted]	[redacted]	0.007
UG-PLT-DMD	0.652	0.010	0.284	0.021	0.033	[redacted]	[redacted]	0.000
UG-PLT-NRG	0.519	0.012	0.381	0.030	0.052	[redacted]	[redacted]	0.007

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ALL451	RS	RT	GS	GST	GP	GT	GT-D	LTG	Total
WP-7	4,256,421	40,846	687,062	54,613	15,742	[redacted]		62,234	5,157,790
Factor	0.825	0.008	0.133	0.011	0 003	[redacted]		0.012	1 000
ALL901	RS	RT	GS	GST	GP	[redacted]		LTG	Total
WP-8	986,002	19,777	227,280	3,077	1,853	[redacted]		3,249	1,242,736
Factor	0.793	0.016	0.183	0.002	0 001	[redacted]		0.003	1 000
ALL905	RS	RT	GS	GST	GP	[redacted]		LTG	Total
WP-8	986,002	19,777	227,280	3,077	1,853	[redacted]		3,249	1,242,736
Factor	0.793	0.016	0.183	0.002	0 001	[redacted]		0.003	1 000
CUST-GTA&G	RS	RT	GS	GST	GP	[redacted]		LTG	Total
Factor	0	0	0	0	0	[redacted]		0	1 000
CUST-ALL	RS	RT	GS	GST	GP	[redacted]		LTG	Total
WP-3	986,002	15,213	125,569	197	423	[redacted]		2,938	1,130,506
Factor	0.872	0.013	0.111	0.000	0 000	[redacted]		0.003	1 000
CUST-DEP	RS	RT	GS	GST	GP	[redacted]		LTG	Total
WP-3 (Excl LTG)	986,002	15,213	125,569	197	423	[redacted]			1,127,568
Factor	0.874	0.013	0.111	0.000	0 000	[redacted]		0.000	1 000
CUST-LTG	RS	RT	GS	GST	GP	[redacted]		LTG	Total
WP-3						[redacted]		2,938	2,938
Factor	0.000	0.000	0.000	0.000	0 000	[redacted]		1.000	1 000
CUST-MTR	RS	RT	GS	GST	GP	[redacted]		LTG	Total
WP-9/15	76,227,441	1,148,308	9,647,316	68,874	7,817,222	[redacted]		0	104,869,792
Factor	0.727	0.011	0.092	0.001	0 075	[redacted]		0.000	1 000
CUST-PRI	RS	RT	GS	GST	GP	[redacted]		LTG	Total
WP-3	986,002	15,213	125,569	197	423	[redacted]		2,938	1,130,342
Factor	0.872	0.013	0.111	0.000	0 000	[redacted]		0.003	1 000
CUST-SEC	RS	RT	GS	GST	GP	[redacted]		LTG	Total
WP-3	986,002	15,213	125,569	197		[redacted]		2,938	1,129,919
Factor	0.873	0.013	0.111	0.000	0 000	[redacted]		0.003	1 000
CUST-SVCS	RS	RT	GS	GST	GP	[redacted]		LTG	Total
WP-3	986,002	15,213	125,569	197		[redacted]			1,126,981
Factor	0.875	0.013	0.111	0.000	0 000	[redacted]		0.000	1 000
CWC-CUST	RS	RT	GS	GST	GP	[redacted]		LTG	Total
O&M minus A&G	20,491,101	308,683	2,593,346	18,514	2,101,389	[redacted]			28,158,172
Factor	0.728	0.011	0.092	0.001	0 075	[redacted]		0.000	1 000
CWC-DMD	RS	RT	GS	GST	GP	[redacted]		LTG	Total
O&M minus A&G	36,339,850	927,870	18,202,763	1,232,109	1,566,298	[redacted]		4,078,745	62,347,636
Factor	0.583	0.015	0.292	0.020	0 025	[redacted]		0.065	1 000
CWC-NRG	RS	RT	GS	GST	GP	[redacted]		LTG	Total
O&M minus A&G	23,587,370	546,272	16,706,380	1,311,053	2,134,316	[redacted]		288,151	44,586,698
Factor	0.529	0.012	0.375	0.029	0 048	[redacted]		0.006	1 000

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DPR-TOT-CUST	RS	RT	GS	GST	GP	GT	GT-D	LTG	Total
Acct 403	8,856,163	134,421	1,123,026	6,053	624,211	[redacted]	[redacted]	0	11,539,239
Factor	0.767	0.012	0.097	0.001	0 054	[redacted]	[redacted]	0.000	1 000
DPR-TOT-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Acct 403	36,503,327	680,927	16,606,323	1,179,481	1,254,802	[redacted]	[redacted]	8,105,252	64,533,237
Factor	0.566	0.011	0.257	0.018	0 019	[redacted]	[redacted]	0.126	1 000
DPR-TOT-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Acct 403	22,850,582	532,908	16,754,452	1,332,681	1,710,660	[redacted]	[redacted]	289,792	43,795,440
Factor	0.522	0.012	0.383	0.030	0 039	[redacted]	[redacted]	0.007	1 000
DIST-PLT-CUST	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Dist PIS	311,924,744	4,773,834	39,639,785	137,269	10,921,646	[redacted]	[redacted]	0	381,313,536
Factor	0.818	0.013	0.104	0.000	0 029	[redacted]	[redacted]	0.000	1 000
DIST-PLT-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Dist PIS	1,649,817,255	27,939,197	731,589,565	52,651,227	52,762,546	[redacted]	[redacted]	264,684,116	2,779,443,906
Factor	0.594	0.010	0.263	0.019	0 019	[redacted]	[redacted]	0.095	1 000
DIST-PLT-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Dist PIS	1,001,889,663	23,365,499	734,603,265	58,431,742	71,494,005	[redacted]	[redacted]	12,706,003	1,902,490,176
Factor	0.527	0.012	0.386	0.031	0 038	[redacted]	[redacted]	0.007	1 000
DIST-REV-CUST	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-4 Dist Revenue	30,980,844	886,940	9,291,578	94,289	250,047	[redacted]	[redacted]	0	41,918,982
Factor	0.739	0.021	0.222	0.002	0 006	[redacted]	[redacted]	0.000	1 000
DIST-REV-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-4 Dist Revenue	0	0	95,229,974	8,719,365	19,685,757	[redacted]	[redacted]	12,839,173	150,980,629
Factor	0.000	0.000	0.631	0.058	0.130	[redacted]	[redacted]	0.085	1 000
DIST-REV-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-4 Dist Revenue	252,595,861	5,482,095	75,049,042	2,309,794	5,448,473	[redacted]	[redacted]	4,994,139	349,969,157
Factor	0.722	0.016	0.214	0.007	0 016	[redacted]	[redacted]	0.014	1 000
DMD-ALL	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-12 DMD	3,110,797	49,303	1,356,865	98,494	286,892	[redacted]	[redacted]	484	5,197,613
Factor	0.599	0.009	0.261	0.019	0 055	[redacted]	[redacted]	0.000	1 000
DMD-LTG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-12						[redacted]	[redacted]	484	484
Factor	0.000	0.000	0.000	0.000	0 000	[redacted]	[redacted]	1.000	1 000
DMD-MTR	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-9/15	29,464,090	4,469,309	39,601,024	1,860,024	0	[redacted]	[redacted]	0	75,394,447
Factor	0.391	0.059	0.525	0.025	0 000	[redacted]	[redacted]	0.000	1 000

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DMD-PRI	RS	RT	GS	GST	GP	GT	GT-D	LTG	Total
WP-12	3,110,797	49,303	1,356,865	98,494	286,892	[redacted]		484	4,902,833
Factor	0.634	0.010	0.277	0.020	0 059			0.000	1 000
DMD-SEC	RS	RT	GS	GST	GP			LTG	Total
WP-12	3,110,797	49,303	1,356,865	98,494				484	4,615,941
Factor	0.674	0.011	0.294	0.021	0 000			0.000	1 000
LATEPAY	RS	RT	GS	GST	GP			LTG	Total
Forfeited Discnt (WP-7)	347	0	1,833,682	65,385	234,858			293,510	2,247,882
Factor	0.000	0.000	0.816	0.029	0.104			0.131	1 000
NRG-ALL	RS	RT	GS	GST	GP			LTG	Total
WP-2	10,003,450	233,295	7,334,707	583,417	1,812,153			126,864	22,206,312
Factor	0.450	0.011	0.330	0.026	0 082			0.006	1 000
NRG-PRI	RS	RT	GS	GST	GP			LTG	Total
WP-2	10,003,450	233,295	7,334,707	583,417	1,812,153			126,864	20,093,885
Factor	0.498	0.012	0.365	0.029	0 090			0.006	1 000
NRG-SEC	RS	RT	GS	GST	GP			LTG	Total
WP-2	10,003,450	233,295	7,334,707	583,417				126,864	18,281,733
Factor	0.547	0.013	0.401	0.032	0 000			0.007	1 000
OHL-PLT-DMD	RS	RT	GS	GST	GP			LTG	Total
OH Lines Plt - 364, 365	684,580,175	10,849,797	298,599,669	21,675,057	30,156,749			106,402	1,045,967,848
Factor	0.654	0.010	0.285	0.021	0 029			0.000	1 000
OHL-PLT-NRG	RS	RT	GS	GST	GP			LTG	Total
OH Lines Plt - 364, 365	465,161,966	10,848,242	341,065,001	27,128,959	40,862,826			5,899,202	890,966,195
Factor	0.522	0.012	0.383	0.030	0 046			0.007	1 000
PAY-CUST	RS	RT	GS	GST	GP			LTG	Total
S&W Alloc * O&M Cust	7,241,180	109,083	916,441	6,543	742,592			0	10,054,916
Factor	0.720	0.011	0.091	0.001	0 074			0.000	1 000
PAY-DMD	RS	RT	GS	GST	GP			LTG	Total
S&W Alloc * O&M DMD	24,219,613	508,217	11,395,273	795,646	1,602,811			1,443,122	39,964,682
Factor	0.606	0.013	0.285	0.020	0 040			0.036	1 000
PAY-NRG	RS	RT	GS	GST	GP			LTG	Total
S&W Alloc * O&M NRG	16,184,135	376,087	11,658,601	921,056	2,176,058			201,366	31,521,952
Factor	0.513	0.012	0.370	0.029	0 069			0.006	1 000
PWRGD	RS	RT	GS	GST	GP			LTG	Total
WP-11 Pwr Guard Rev	251,400	11,170	11,650						274,221
Factor	0.917	0.041	0.042	0.000	0 000			0.000	1 000
RB-CUST	RS	RT	GS	GST	GP			LTG	Total
Total Rate Base	109,867,448	1,668,237	13,933,379	73,862	7,546,800			0	142,617,859
Factor	0.770	0.012	0.098	0.001	0 053			0.000	1 000

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RB-DMD	RS	RT	GS	GST	GP	GT	GT-D	LTG	Total
Total Rate Base	853,870,797	14,777,396	380,758,536	27,323,403	31,368,062	[redacted]	[redacted]	113,701,475	1,427,549,708
Factor	0.598	0.010	0.267	0.019	0 022	[redacted]	[redacted]	0.080	1 000
RB-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Total Rate Base	534,671,162	12,467,165	391,702,262	31,146,813	42,804,828	[redacted]	[redacted]	6,774,594	1,028,756,227
Factor	0.520	0.012	0.381	0.030	0 042	[redacted]	[redacted]	0.007	1 000
RB-PLT-CUST	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Rate Base Plt (D,G,I, PTY)	313,773,776	4,802,132	39,874,762	138,083	10,986,387	[redacted]	[redacted]	0	383,573,892
Factor	0.818	0.013	0.104	0.000	0 029	[redacted]	[redacted]	0.000	1 000
RB-PLT-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Rate Base Plt (D,G,I, PTY)	1,794,744,443	30,246,744	794,874,774	57,242,346	65,539,215	[redacted]	[redacted]	266,274,119	3,021,728,256
Factor	0.594	0.010	0.263	0.019	0 022	[redacted]	[redacted]	0.088	1 000
RB-PLT-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Rate Base Plt (D,G,I, PTY)	1,104,672,562	25,762,543	809,965,509	64,426,198	89,461,345	[redacted]	[redacted]	14,009,500	2,128,748,158
Factor	0.519	0.012	0.380	0.030	0 042	[redacted]	[redacted]	0.007	1 000
REV-ALL	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Dist Revenues	283,576,706	6,369,034	179,570,595	11,123,447	25,384,277	[redacted]	[redacted]	17,833,311	542,868,768
Factor	0.522	0.012	0.331	0.020	0 047	[redacted]	[redacted]	0.033	1 000
SRVC-CUST	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-18	355,908,356	5,339,140	82,430,952	362,086	0	[redacted]	[redacted]	0	444,040,534
Factor	0.802	0.012	0.186	0.001	0 000	[redacted]	[redacted]	0.000	1 000
SRVC-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-18	164,940	1,121	25,341,645	46,154	0	[redacted]	[redacted]	0	25,553,860
Factor	0.006	0.000	0.992	0.002	0 000	[redacted]	[redacted]	0.000	1 000
SSEQ-PLT-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Sub St Equip PIS - 362	186,562,569	2,956,799	81,374,722	5,906,911	8,218,352	[redacted]	[redacted]	28,997	285,048,349
Factor	0.654	0.010	0.285	0.021	0 029	[redacted]	[redacted]	0.000	1 000
SSEQ-PLT-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Sub St Equip PIS - 362	126,766,469	2,956,375	92,947,422	7,393,215	11,135,984	[redacted]	[redacted]	1,607,657	242,807,122
Factor	0.522	0.012	0.383	0.030	0 046	[redacted]	[redacted]	0.007	1 000
UG-PLT-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
UG Lines Plt - 366, 367	259,309,593	4,109,755	113,105,464	8,210,215	12,948,076	[redacted]	[redacted]	40,304	397,723,406
Factor	0.652	0.010	0.284	0.021	0 033	[redacted]	[redacted]	0.000	1 000
UG-PLT-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
UG Lines Plt - 366, 367	176,524,658	4,116,807	129,431,009	10,295,189	17,544,829	[redacted]	[redacted]	2,238,692	340,151,184
Factor	0.519	0.012	0.381	0.030	0 052	[redacted]	[redacted]	0.007	1 000

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CF	Factor
A&G-GT-CUST	0.003
AE-ALL-DMD	0.512
AE-ALL-NRG	0.488
AE-PRI-DMD	0.532
AE-PRI-DMD-GTA&G	0.531
AE-PRI-NRG	0.468
AE-PRI-NRG-GTA&G	0.467
AE-SEC-DMD	0.548
AE-SEC-NRG	0.452
CUST	1.000
CWC-CUST	0.209
CWC-DMD	0.461
CWC-NRG	0.330
DIST-CLA-DMD	0.594
DIST-CLA-NRG	0.406
DIST-PLT-CUST	0.075
DIST-PLT-DMD	0.549
DIST-PLT-NRG	0.376
DIST-REV-CUST	0.077
DIST-REV-DMD	0.278
DIST-REV-NRG	0.645
DMD	1.000
DPR-G&I-DMD	0.512
DPR-G&I-NRG	0.488
DPR-TOT-CUST	0.096
DPR-TOT-DMD	0.538
DPR-TOT-NRG	0.365
MTR-CUST	0.813
MTR-DMD	0.187
NONE	0.000
NRG	1.000
OHL-PLT-DMD	0.540
OHL-PLT-NRG	0.460
PAY-CUST	0.123
PAY-DMD	0.490
PAY-NRG	0.387
RB-CUST	0.055
RB-DMD	0.549
RB-NRG	0.396
RB-PLT-CUST	0.069
RB-PLT-DMD	0.546
RB-PLT-NRG	0.385
SRVC-CUST	0.500
SRVC-DMD	0.500
SSEQ-PLT-DMD	0.540
SSEQ-PLT-NRG	0.460
UG-PLT-DMD	0.539
UG-PLT-NRG	0.461

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		Customer	Demand	Energy	Total
Avg/Excess All	Dist - All		*See WP-6 Voltage Specific Load Factors Tab*		
WP-6	AE-ALL-***	0 0%	51 2%	48.8%	100 0%
		Customer	Demand	Energy	Total
Avg/Excess Primary	Dist - Primary		*See WP-6 Voltage Specific Load Factors Tab*		
WP-6	AE-PRI-***	0 0%	53 2%	46.8%	100 0%
		Customer	Demand	Energy	Total
Avg/Exc Secondary	Dist - Secondary		*See WP-6 Voltage Specific Load Factors Tab*		
WP-6	AE-SEC-***	0 0%	54.8%	45.2%	100 0%
		Customer	Demand	Energy	Total
Avg/Exc for GT A&G	Dist - Primary		*See WP-6 Voltage Specific Load Factors Tab*		
WP-6	AE-PRI-***-GTA&G	0 275%	53.1%	46.7%	100 0%
		Customer	Demand	Energy	Total
Cash Working Cap	O&M minus A&G Exp	$28,190,603	$62,347,636	$44,586,698	$135,124,936
	CWC-***	20 9%	46.1%	33.0%	100 0%
		Customer	Demand	Energy	Total
Deprec Exp - G&I	Acct 403 G&I Depr Exp	$0	($123,574,518)	($117,648,878)	($241,223,397)
	DPR-G&I-***	0 0%	51.2%	48.8%	100 0%
		Customer	Demand	Energy	Total
Deprec Exp - Tot	Acct 403 - Depr Exp	$11,539,239	$64,533,237	$43,795,440	$119,867,916
	TOT-DPR-***	9.6%	53.8%	36.5%	100 0%
		Customer	Demand	Energy	Total
Distribution Plant	Dist PIS	$381,313,536	$2,779,443,906	$1,902,490,176	$5,063,247,618
	DIST-PLT-***	7 5%	54.9%	37.6%	100 0%
		Customer	Demand	Energy	Total
Distribution Revs	Dist Revenues	$41,918,982	$150,980,629	$349,969,157	$542,868,768
WP-4	DIST-REV-***	7.7%	27.8%	64.5%	100 0%
		Customer	Demand	Energy	Total
Meter Expense			*See WP-15 Meter Cost Tab*		
WP-15	MTR-***	81 3%	18.7%	0.0%	100 0%
		Customer	Demand	Energy	Total
Misc Exp	Acct 588	$0	$2,779,443,906	$1,902,490,176	$4,681,934,082
	DIST-CLA-***	0 0%	59.4%	40.6%	100 0%
		Customer	Demand	Energy	Total
OH Lines - Plant	Acct 364 - 365	$0	$1,045,967,848	$890,966,195	$1,936,934,044
	OH-PLT-***	0 0%	54.0%	46.0%	100 0%
		Customer	Demand	Energy	Total
Payroll & Unemp	Acct 408	$10,054,916	$39,964,682	$31,521,952	$81,541,550
WP-10	PAY-***	12 3%	49.0%	38.7%	100 0%
		Customer	Demand	Energy	Total
Rate Base	Total Rate Base	$142,617,859	$1,427,549,708	$1,028,756,227	$2,598,923,793
	RB-***	5 5%	54.9%	39.6%	100 0%
		Customer	Demand	Energy	Total
Rate Base Plant	Rate Base Plt (D,G,I, PTY)	$383,573,892	$3,021,728,256	$2,128,748,158	$5,534,050,306
	RB-PLT-***	6 9%	54.6%	38.5%	100 0%
		Customer	Demand	Energy	Total
Services Plant	Acct 369 - Services	$234,797,197	$234,797,197	$0	$469,594,395
	SRVC-***	50 0%	50.0%	0.0%	100 0%
		Customer	Demand	Energy	Total
Substation Plant	Acct 362 - Sub Equip	$0	$285,048,349	$242,807,122	$527,855,471
	SSEQ-PLT-***	0 0%	54.0%	46.0%	100 0%
		Customer	Demand	Energy	Total
UG Lines - Plant	Acct 366 - 367	$0	$397,723,406	$340,151,184	$737,874,590
	UG-PLT-***	0 0%	53.9%	46.1%	100 0%

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Account	Description	Total	Primary Factor	Primary	Secondary
108-303	Misc Intangible Plant - Accum Res	($86,519,616)			
108-360	Land & Land Rights - Accum Res	($18,452,898)	50.0%	($9,226,449)	($9,226,449)
108-361	Struct & Impmnts - Accum Res	($14,264,483)	50.0%	($7,132,242)	($7,132,242)
108-362	Station Equip - Accum Res	($194,116,809)	50.0%	($97,058,405)	($97,058,405)
108-364	Poles, Towers & Fixt - Accum Res	($252,451,123)	50.0%	($126,225,561)	($126,225,561)
108-365	OH Cond & Dev - Accum Res	($183,403,589)	50.0%	($91,701,795)	($91,701,795)
108-366	UG Conduit - Accum Res	($59,519,249)	90.0%	($53,567,324)	($5,951,925)
108-367	UG Cond & Dev - Accum Res	($222,969,186)	50.0%	($111,484,593)	($111,484,593)
108-368	Line Transformers - Accum Res	($289,146,526)			
108-369	Services - Accum Res	($189,580,347)			
108-370	Meters - Accum Res	($35,341,484)			
108-371	Install on Cust Premise - Accum Res	($8,345,814)			
108-373	St Lt & Signal Sys - Accum Res	($86,922,368)			
108-374	Asset Ret Costs - Accum Res	($28,356)			
108-389	Land & Land Rights - Accum Res	($5,722)			
108-390	Struct & Impmnts - Accum Res	($54,183,893)			
108-391	Office Furn & Equip - Accum Res	($6,118,526)			
108-392	Transportation Equip - Accum Res	($3,822,686)			
108-393	Stores Equip - Accum Res	($1,257,964)			
108-394	Tools, Shop & Garage Equip - Accum Res	($10,790,043)			
108-395	Laboratory Equip - Accum Res	($448,981)			
108-396	Power Operated Equip - Accum Res	($2,847,208)			
108-397	Communication Equip - Accum Res	($4,859,396)			
108-398	MISC Equip - Accum Res	($921,377)			
108-399	Other Tangible Property - Accum Res	($614,344)			
SRVCO-PIS	Service Company PIS - Accum Res	(68,833,640)			
301	Organization	$45,044			
302	Franchise and Consents	$15,029			
303	Misc Intangible Plant	$126,008,783			
360	Land & Land Rights	$32,657,627	50.0%	$16,328,813	$16,328,813
361	Struct & Impmnts	$59,700,110	50.0%	$29,850,055	$29,850,055
362	Station Equip	$527,855,471	50.0%	$263,927,736	$263,927,736
364	Poles, Towers & Fixtures	$753,081,665	50.0%	$376,540,833	$376,540,833
365	OH Cond & Dev	$1,183,852,378	50.0%	$591,926,189	$591,926,189
366	UG Conduit	$117,207,235	90.0%	$105,486,511	$11,720,723
367	UG Cond & Dev	$620,667,356	50.0%	$310,333,678	$310,333,678
368	Line Transformers	$853,891,746			
369	Services	$469,594,395			
370	Meters	$180,264,239			
371	Install on Cust Premise	$25,980,444			
373	St Lt & Signal Sys	$238,449,297			
374	Asset Retirement Costs	$45,657			
389	Land & Land Rights	$1,494,290			
390	Struct & Impmnts	$92,717,272			
391	Office Furn & Equip	$29,278,765			
392	Transportation Equip	$8,780,078			
393	Stores Equip	$1,490,362			
394	Tools, Shop & Garage Equip	$23,055,243			
395	Laboratory Equip	$448,981			
396	Power Operated Equip	$3,851,265			
397	Communication Equip	$36,284,526			
398	MISC Equip	$1,384,722			
399	Other Tangible Property	$1,458,070			
SRVCO-PIS	Service Company PIS	114,476,272			
RB-CUSTDEP	Acct 235 - Cust Deposits	($47,386,955)			
RB-CAFC	Acct 252 - Cust Adv for Const	($34,598,405)			
RB-ADIT	Accum Deferred Inc Tx	($1,102,329,656)			
RB-REAQDBT	Unamort G/L on Reaquired Debt	$2,178,358			
RB-M&S	Materials & Supplies	$22,844,588			
RB-CWC	Cash Working Capital	$114,525,841			

Jersey Central Power & Light
Direct Input Sheet
Test Year: July 2019 - June 2020
Complied COSS

Account	Description	Total	Primary Factor	Primary	Secondary
RB-EXCOR	Unamort Excess Cost of Removal	($87,758,072)			
RB-REF	Customer Refunds	($4,033,419)			
RB-OPRES	Net Operating Reserves	($10,699,965)			
RB-NOL	NOL	$22,826,438			
RB-CTA	CTA	($20,787,390)			
RB-PRAMT	Property-Related Unprotected Amort	$32,052,681			
403-360	Land & Land Rights - Deprec Exp	$192,735	50.0%	$96,368	$96,368
403-361	Struct & Impmnts - Deprec Exp	$675,035	50.0%	$337,518	$337,518
403-362	Station Equip - Deprec Exp	$7,538,342	50.0%	$3,769,171	$3,769,171
403-364	Poles, Towers & Fixt - Deprec Exp	$18,158,038	50.0%	$9,079,019	$9,079,019
403-365	OH Cond & Dev - Deprec Exp	$26,911,530	50.0%	$13,455,765	$13,455,765
403-366	UG Conduit - Deprec Exp	$1,501,346	90.0%	$1,351,211	$150,135
403-367	UG Cond & Dev - Deprec Exp	$11,717,310	50.0%	$5,858,655	$5,858,655
403-368	Line Transformers - Deprec Exp	$21,448,336			
403-369	Services - Deprec Exp	$6,330,609			
403-370	Meters - Deprec Exp	$10,302,747			
403-371	Install on Cust Premise - Deprec Exp	$910,175			
403-373	St Lt & Signal Sys - Deprec Exp	$7,189,520			
403-374	Asset Retirement Costs - Deprec Exp	$850			
403-389	Land & Land Rights - Deprec Exp	$377			
403-390	Struct & Impmnts - Deprec Exp	$1,494,037			
403-391	Office Furn & Equip - Deprec Exp	$1,903,796			
403-392	Transportation Equip - Deprec Exp	$535,910			
403-393	Stores Equip - Deprec Exp	$44,353			
403-394	Tools, Shop & Garage Equip - Deprec Exp	$1,215,535			
403-396	Power Operated Equip - Deprec Exp	$16,999			
403-397	Communication Equip - Deprec Exp	$1,691,857			
403-398	MISC Equip - Deprec Exp	$17,967			
403-399	Other Tangible Property - Deprec Exp	$70,511			
404	Amort - Ltd Term Elec Prpty	$8,815,151			
407-TMI/OC	Amort - TMI and OC	$109,008			
407-STRM	Amort - Storm Exp	$25,566,878			
407-COR	Amort - Cost of Removal	($3,124,154)			
407-ARO	Amort - ARO ACCR & DEP	($9,421,269)			
411.1	Accretion Expense	$9,380,189			
408-PPTYTX	Txs Otr Inc - Property Tax	$4,935,959			
408-PAY	Txs Otr Inc - Payroll & Unemp	$4,621,369			
REV	Rev - Retail Distribution	$542,868,768			
450	Rev - Elec Frft Discount	$2,247,882			
451	Rev - Misc Service	$5,157,789			
454	Rev - Rent from Elec Prpty	$6,481,819			
456PG	Other Elec Revs - Pwr Guard	$1,655,608			
524	Misc Nuclear Pwr Exp	$0			
580	OP Supv & Eng	$89,279	36.7%	$32,754	$56,525
581	Load Dispatching	$1,283,749			
582	Station Exp	$586,634	50.0%	$293,317	$293,317
583	OH Line Exp	$1,386,851	50.0%	$693,425	$693,425
584	UG Line Exp	$3,370,232	50.0%	$1,685,116	$1,685,116
585	St Lt & Signal Sys Exp	$0			
586	Meter Exp	$1,124,469			
588	Misc Exp	17,308,525			
589	Rent	6,177,282	36.7%	$2,266,262	$3,911,020
590	Maint Supv & Engr	1,617,484	36.7%	$593,407	$1,024,077
591	Maint of Structures	119,074			
592	Maint of Station Equip	10,654,296	50.0%	$5,327,148	$5,327,148
593	Maint of OH Lines	36,695,799	50.0%	$18,347,900	$18,347,900
594	Maint of UG Lines	3,597,029	50.0%	$1,798,515	$1,798,515
595	Maint of Line Trnsfrmrs	350,274			
596	Maint of St Lt & Signal Sys	3,006,789			
597	Maint of Meters	4,870,664			
598	Maint of Misc Dist Plant	1,578,429			
901	Supervision	$38,021			
902	Meter Reading Exp	$14,235,371			
903	Cust Records & Collect Exp	$14,453,393			

Jersey Central Power & Light
Direct Input Sheet
Test Year: July 2019 - June 2020
Complied COSS

Account	Description	Total	Primary Factor	Primary	Secondary
904	Cust Uncollect Exp	$119,609			
905	Misc Cust Acct Exp	$1,436,938			
907	Supervision	$368,340			
908	Cust Assist Exp	$1,214,314			
909	Info & Instrctnl Advertising	$2,400			
910	Misc Cust Srvc & Info Exp	$9,383,308			
911	Sales Exp	$56,383			
920	A&G Salaries	$850,366			
921	Office Supplies & Exp	$1,085,146			
922	Admin Exp Trnsfr Credit	$0			
923	Outside Services	$32,961,974			
924	Property Insurance	$253,345			
925	Injuries & Damages	$3,344,187			
926	Pensions & Benefits	$44,294,361			
928	Regulatory Comms Exp	$4,483,645			
930.1	Gen Advertising Exp	$996,585			
930.2	Misc Gen Exp	$2,279,321			
931	Rents	$2,510,095			
935	Maint of Gen Plant	$2,562,438			
INTEXP	Interest Expense	$62,352,756			
STTXEXP	State Income Tax Rate	9.0%			
FEDTXEXP	Federal Income Tax Rate	21.0%			
	Composite Tax Gross-up Factor	1.391			
FEDITC	Amortization of Fed Income Tax Credit	(97,625)			
FEDTAXRFM	Federal Tax Reform Amortization	(5,291,287)			
ADJ-1	Revenue Normalization	($319,110)			
ADJ-2	Tariff Fee Adjustments	$51,028			
ADJ-3	Int on Cust Deposits	1,104,116			
ADJ-4	Annualize Payroll Increase	$4,511,619			
ADJ-4a	Svngs Pln Match on Payroll Inc	135,349			
ADJ-4b	FICA on Payroll Increase	$345,139			
ADJ-5	Reclass G/L on Reaquired Debt	638,187			
ADJ-6	BPU & RPA Assessments	($425,441)			
ADJ-7	Return Net Gain on Sale of Property	($101,996)			
ADJ-8	Rate Case Exp	$156,039			
ADJ-9	OPEB Settlement	$1,187,500			
ADJ-10a	Pension Smoothing	($25,638,726)			
ADJ-10b	OPEB Smoothing	$7,176,427			
ADJ-11	Normalize Forestry Maint Exp	$5,808,721			
ADJ-12	Amort Forestry Reg Asset	$2,894,215			
ADJ-13	Annualize Deprec Exp	$17,988,446			
ADJ-14	Average Net Salvage	$7,788,834			
ADJ-15	Amort Storm Damage Exp	$76,863,146			
ADJ-16	ServCo Depr @ JCP&L Rates	$1,710,308			
ADJ-17	SERP/EDCP	($1,181,606)			
ADJ-18	Removal of Certain Advertising Expense	($924,095)			
ADJ-19	Holding Company Costs	$147,821			
ADJ-20	ARAM	$131,215			
ADJ-21	LED Amortization	$0			
ADJ-22	Production Related Regulatory Asset Amortizatic	$1,211,786			
ADJ-23	Service Company O&M	$3,407,305			
PTYADDS	RB Post Test-Year Additions- 6mo CAPEX	$30,013,986			
PTYDPRRES	RB Post Test-Year Deprec Reserve- 6mo CAPEX	($663,309)			
RB-IIPADD	RB IIP Incremental Plant Additions	$31,402,232			
RB-IIPDEP	RB IIP Incremental Deprec Reserve	(758,683)			
RB-P&OPEBADD	RB Delayed Recog Pension & OPEB Additions	($68,892,010)			
RB-P&OPEBDEP	RB Delayed Recog Pension & OPEB Deprec Reser	$12,716,844			
Dist Rev Change	RS Change in Dist Rev	$102,458,038			
Dist Rev Change	RT Change in Dist Rev	$2,080,000			
Dist Rev Change	GS Change in Dist Rev	$61,580,000			
Dist Rev Change	GST Change in Dist Rev	$4,040,000			
Dist Rev Change	GP Change in Dist Rev	$7,850,000			
Dist Rev Change	GT Change in Dist Rev	$5,788,000			
Dist Rev Change	GT-D Change in Dist Rev	$89,900			
Dist Rev Change	LTG Change in Dist Rev	$3,060,000			
	Required Rate of Return	7.76%			

REDACTED

Jersey Central Power & Light
Proposed Distribution Revenue Requirement
Test Year: July 2019 - June 2020
JCP&L's Proposed Alternative COSS

	Customer	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
1	Rate Base	$221,621,793	$149,995,145	$3,725,948	$55,003,041	$684,147	$5,396,188	[redacted]	[redacted]	$0
2	Rate of Return	8.85%	6.74%	8.76%	8.62%	7.73%	15.97%	[redacted]	[redacted]	3.19%
3	Net Operating Income (Return on Rate Base)	$19,611,285	$10,114,859	$326,261	$4,743,388	$52,911	$861,984	[redacted]	[redacted]	$0
4	Interest Expense	$5,317,097	$3,598,648	$89,392	$1,319,620	$16,414	$129,464	[redacted]	[redacted]	$0
5	Net Income	$14,294,189	$6,516,212	$236,869	$3,423,768	$36,498	$732,520	[redacted]	[redacted]	$0
6	Federal Income Tax	$3,799,721	$1,732,157	$62,965	$910,116	$9,702	$194,720	[redacted]	[redacted]	$0
7	State Income Tax	$1,789,508	$815,773	$29,654	$428,626	$4,569	$91,705	[redacted]	[redacted]	$0
8	Investment Tax Credit	($8,325)	($5,634)	($140)	($2,066)	($26)	($203)	[redacted]	[redacted]	$0
9	Federal Tax Reform	($451,212)	($305,383)	($7,586)	($111,984)	($1,393)	($10,986)	[redacted]	[redacted]	$0
10	Rate Base Revenue Requirement	$24,561,292	$12,230,160	$408,133	$5,923,485	$65,209	$1,132,845	[redacted]	[redacted]	$0
11	Operating Expenses	$47,062,572	$34,086,420	$1,087,367	$7,014,355	$164,652	$1,989,343	[redacted]	[redacted]	$0
12	Total Distribution Revenue Requirement	$71,623,864	$46,316,580	$1,495,500	$12,937,840	$229,861	$3,122,188	[redacted]	[redacted]	$0
13	Other Operating Revenue	$756,013	$585,466	$11,667	$134,843	$1,279	$10,007	[redacted]	[redacted]	$0
14	Distribution Rate Schedule Revenues	$70,867,851	$45,731,114	$1,483,832	$12,802,996	$228,582	$3,112,181	[redacted]	[redacted]	$0
15										
16	**Demand**	**Total**	**RS**	**RT**	**GS**	**GST**	**GP**	**GT**	**GT-D**	**LTG**
17	Rate Base	$1,998,401,970	$1,109,288,261	$18,649,486	$649,103,894	$41,875,045	$40,243,774	[redacted]	[redacted]	$128,326,354
18	Rate of Return	7.54%	6.74%	8.76%	8.62%	7.73%	15.97%	[redacted]	[redacted]	3.19%
19	Net Operating Income (Return on Rate Base)	$150,738,212	$74,804,384	$1,633,032	$55,977,847	$3,238,589	$6,428,517	[redacted]	[redacted]	$4,090,086
20	Interest Expense	$47,945,180	$26,613,778	$447,434	$15,573,145	$1,004,656	$965,519	[redacted]	[redacted]	$3,078,775
21	Net Income	$102,793,031	$48,190,606	$1,185,598	$40,404,702	$2,233,933	$5,462,998	[redacted]	[redacted]	$1,011,311
22	Federal Income Tax	$27,324,730	$12,810,161	$315,159	$10,740,490	$593,830	$1,452,189	[redacted]	[redacted]	$268,830
23	State Income Tax	$12,868,790	$6,033,043	$148,426	$5,058,316	$279,669	$683,920	[redacted]	[redacted]	$126,607
24	Investment Tax Credit	($75,067)	($41,669)	($701)	($24,383)	($1,573)	($1,512)	[redacted]	[redacted]	($4,820)
25	Federal Tax Reform	($4,068,652)	($2,258,459)	($37,969)	($1,321,545)	($85,256)	($81,934)	[redacted]	[redacted]	($261,266)
26	Rate Base Revenue Requirement	$185,167,759	$90,448,078	$2,042,827	$69,904,448	$3,991,308	$8,448,551	[redacted]	[redacted]	$4,115,393
27	Operating Expenses	$366,732,289	$201,260,644	$3,619,033	$117,477,721	$7,735,525	$13,457,266	[redacted]	[redacted]	$16,911,587
28	Total Distribution Revenue Requirement	$551,900,048	$291,708,722	$5,661,860	$187,382,169	$11,726,833	$21,905,816	[redacted]	[redacted]	$21,026,980
29	Other Operating Revenue	$13,660,659	$8,354,490	$149,679	$4,049,020	$215,598	$321,348	[redacted]	[redacted]	$720,326
30	Distribution Rate Schedule Revenues	$538,239,390	$283,354,233	$5,512,181	$183,333,149	$11,511,236	$21,584,469	[redacted]	[redacted]	$20,306,655
31										
32	**Energy**	**Total**	**RS**	**RT**	**GS**	**GST**	**GP**	**GT**	**GT-D**	**LTG**
33	Rate Base	$378,900,030	$196,724,653	$4,585,770	$143,913,890	$11,437,255	$15,732,218	[redacted]	[redacted]	$2,488,743
34	Rate of Return	8.27%	6.74%	8.76%	8.62%	7.73%	15.97%	[redacted]	[redacted]	3.19%
35	Net Operating Income (Return on Rate Base)	$31,326,988	$13,266,044	$401,550	$12,410,940	$884,550	$2,513,055	[redacted]	[redacted]	$79,323
36	Interest Expense	$9,090,479	$4,719,771	$110,021	$3,452,748	$274,400	$377,444	[redacted]	[redacted]	$59,709
37	Net Income	$22,236,510	$8,546,273	$291,530	$8,958,193	$610,150	$2,135,612	[redacted]	[redacted]	$19,613
38	Federal Income Tax	$5,910,971	$2,271,794	$77,495	$2,381,292	$162,192	$567,694	[redacted]	[redacted]	$5,214
39	State Income Tax	$2,783,817	$1,069,919	$36,497	$1,121,487	$76,385	$267,360	[redacted]	[redacted]	$2,455
40	Investment Tax Credit	($14,233)	($7,390)	($172)	($5,406)	($430)	($591)	[redacted]	[redacted]	($93)
41	Federal Tax Reform	($771,423)	($400,522)	($9,336)	($293,002)	($23,286)	($32,030)	[redacted]	[redacted]	($5,067)
42	Rate Base Revenue Requirement	$38,928,918	$16,040,345	$502,316	$15,498,630	$1,090,139	$3,302,733	[redacted]	[redacted]	$79,813
43	Operating Expenses	$82,636,892	$41,360,473	$961,233	$29,846,810	$2,359,818	$5,268,247	[redacted]	[redacted]	$512,568
44	Total Distribution Revenue Requirement	$121,565,811	$57,400,819	$1,463,549	$45,345,440	$3,449,957	$8,570,980	[redacted]	[redacted]	$592,382
45	Other Operating Revenue	$858,345	$451,422	$10,528	$330,991	$26,328	$33,352	[redacted]	[redacted]	$5,725
46	Distribution Rate Schedule Revenues	$120,707,465	$56,949,396	$1,453,021	$45,014,449	$3,423,629	$8,537,628	[redacted]	[redacted]	$586,657
47										
48	**Total Distribution Revenue Requirement**	**Total**	**RS**	**RT**	**GS**	**GST**	**GP**	**GT**	**GT-D**	**LTG**
49	Rate Base	$2,598,923,793	$1,456,008,059	$26,961,204	$848,020,824	$53,996,447	$61,372,180	[redacted]	[redacted]	$130,815,097
50	Rate of Return	7.76%	6.74%	8.76%	8.62%	7.73%	15.97%	[redacted]	[redacted]	3.19%
51	Net Operating Income (Return on Rate Base)	$201,676,486	$98,185,287	$2,360,843	$73,132,175	$4,176,050	$9,803,556	[redacted]	[redacted]	$4,169,409
52	Interest Expense	$62,352,756	$34,932,196	$646,847	$20,345,512	$1,295,470	$1,472,427	[redacted]	[redacted]	$3,138,484
53	Net Income	$139,323,730	$63,253,091	$1,713,996	$52,786,663	$2,880,580	$8,331,129	[redacted]	[redacted]	$1,030,925
54	Federal Income Tax	$37,035,422	$16,814,113	$455,619	$14,031,898	$765,724	$2,214,604	[redacted]	[redacted]	$274,043
55	State Income Tax	$17,442,114	$7,918,734	$214,577	$6,608,429	$360,623	$1,042,985	[redacted]	[redacted]	$129,063
56	Investment Tax Credit	($97,625)	($54,693)	($1,013)	($31,855)	($2,028)	($2,305)	[redacted]	[redacted]	($4,914)
57	Federal Tax Reform	($5,291,287)	($2,964,364)	($54,892)	($1,726,531)	($109,934)	($124,951)	[redacted]	[redacted]	($266,333)
58	Rate Base Revenue Requirement	$248,657,970	$118,718,583	$2,953,275	$91,326,563	$5,146,656	$12,884,129	[redacted]	[redacted]	$4,195,206
59	Operating Expenses	$496,431,754	$276,707,538	$5,667,633	$154,338,886	$10,259,995	$20,714,855	[redacted]	[redacted]	$17,424,156
60	Total Distribution Revenue Requirement	$745,089,723	$395,426,121	$8,620,908	$245,665,449	$15,406,651	$33,598,984	[redacted]	[redacted]	$21,619,362
61	Other Operating Revenue	$15,275,018	$9,391,377	$171,874	$4,514,854	$243,204	$364,707	[redacted]	[redacted]	$726,050
62	Distribution Rate Schedule Revenues	$729,814,706	$386,034,743	$8,449,034	$241,150,595	$15,163,447	$33,234,277	[redacted]	[redacted]	$20,893,311

Jersey Central Power & Light
Present Distribution Rate of Return and Proposed Revenue Calculations
Test Year: July 2019 - June 2020
JCP&L's Proposed Alternative COSS

Line	Description	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
1	Distribution Revenues	$542,868,768	$283,576,706	$6,369,034	$179,570,595	$11,123,447	$25,384,277	[redacted]	[redacted]	$17,833,311
2	Other Operating Revenues	$15,275,018	$9,391,377	$171,874	$4,514,854	$243,204	$364,707	[redacted]	[redacted]	$726,050
3	**Total Operating Revenues**	**$558,143,786**	**$292,968,083**	**$6,540,908**	**$184,085,449**	**$11,366,651**	**$25,748,984**	[redacted]	[redacted]	**$18,559,362**
4								[redacted]	[redacted]	
5	Total O&M Expenses	$227,372,423	$129,121,751	$2,897,097	$72,568,308	$4,763,526	$10,602,485	[redacted]	[redacted]	$5,306,701
6	Total Depreciation Expense	$145,645,195	$82,253,629	$1,628,402	$43,844,180	$2,872,842	$3,140,771	[redacted]	[redacted]	$10,628,956
7	Total Amortization Expense [1]	$113,511,669	$59,694,004	$1,027,729	$34,801,975	$2,420,676	$6,622,210	[redacted]	[redacted]	$1,099,520
8	Total Taxes Other Than Income	$9,902,467	$5,638,154	$114,405	$3,124,422	$202,951	$349,388	[redacted]	[redacted]	$388,979
9	**Total Expenses**	**$496,431,754**	**$276,707,538**	**$5,667,633**	**$154,338,886**	**$10,259,995**	**$20,714,855**	[redacted]	[redacted]	**$17,424,156**
10								[redacted]	[redacted]	
11	**Income Before Taxes**	**$61,712,032**	**$16,260,546**	**$873,275**	**$29,746,563**	**$1,106,656**	**$5,034,129**	[redacted]	[redacted]	**$1,135,206**
12								[redacted]	[redacted]	
13	State Income Taxes	($57,665)	($1,680,449)	$20,379	$846,095	($16,993)	$320,553	[redacted]	[redacted]	($180,295)
14	Federal Income Taxes	($122,442)	($3,568,152)	$43,270	$1,796,541	($36,082)	$680,641	[redacted]	[redacted]	($382,826)
15	Investment Tax Credit	($97,625)	($54,693)	($1,013)	($31,855)	($2,028)	($2,305)	[redacted]	[redacted]	($4,914)
16	Federal Tax Reform	($5,291,287)	($2,964,364)	($54,892)	($1,726,531)	($109,934)	($124,951)	[redacted]	[redacted]	($266,333)
17	**Total Income Taxes**	**($5,569,019)**	**($8,267,658)**	**$7,745**	**$884,250**	**($165,038)**	**$873,938**	[redacted]	[redacted]	**($834,369)**
18								[redacted]	[redacted]	
19	**Net Operating Income**	**$67,281,051**	**$24,528,203**	**$865,531**	**$28,862,313**	**$1,271,694**	**$4,160,191**	[redacted]	[redacted]	**$1,969,575**
20								[redacted]	[redacted]	
21	**Rate Base**	**$2,598,923,793**	**$1,456,008,059**	**$26,961,204**	**$848,020,824**	**$53,996,447**	**$61,372,180**	[redacted]	[redacted]	**$130,815,097**
22								[redacted]	[redacted]	
23	Rate of Return	2.59%	1.68%	3.21%	3.40%	2.36%	6.78%	[redacted]	[redacted]	1 51%
24								[redacted]	[redacted]	
25	**Existing Unitized Rate of Return**		**0.65**	**1.24**	**1.31**	**0.91**	**2.62**	[redacted]	[redacted]	**0.58**
26								[redacted]	[redacted]	
27	**Rate Increase with Equal Rates of Return**							[redacted]	[redacted]	
28	Required Rate of Return	7.76%	7.76%	7.76%	7.76%	7.76%	7.76%	[redacted]	[redacted]	7.76%
29	Required Net Operating Income	$ 201,676,486	$ 112,986,225	$ 2,092,189	$ 65,806,416	$ 4,190,124	$ 4,762,481	[redacted]	[redacted]	$ 10,151,252
30	Change in Net Operating Income	$ 134,395,435	$ 88,458,022	$ 1,226,659	$ 36,944,103	$ 2,918,430	$ 602,291	[redacted]	[redacted]	$ 8,181,677
31	Change in Distribution Revenue	$ 186,945,939	$ 123,046,351	$ 1,706,300	$ 51,389,766	$ 4,059,578	$ 837,795	[redacted]	[redacted]	$ 11,380,827
32								[redacted]	[redacted]	
33	**Rate Increase Using Current Unitized ROR**							[redacted]	[redacted]	
34	Current Unitized ROR	1.00	0.65	1.24	1 31	0 91	2.62	[redacted]	[redacted]	0 58
35	Required Rate of Return	7.76%	5.05%	9.62%	10.20%	7.06%	20.32%	[redacted]	[redacted]	4 51%
36	Required Net Income	$ 201,676,486	$ 73,523,849	$ 2,594,448	$ 86,515,442	$ 3,811,932	$ 12,470,266	[redacted]	[redacted]	$ 5,903,846
37	Change in Net Operating Income	$ 134,395,435	$ 48,995,646	$ 1,728,917	$ 57,653,129	$ 2,540,238	$ 8,310,076	[redacted]	[redacted]	$ 3,934,271
38	Change in Distribution Revenue	$ 186,945,939	$ 68,153,632	$ 2,404,948	$ 80,196,313	$ 3,533,506	$ 11,559,432	[redacted]	[redacted]	$ 5,472,626
39								[redacted]	[redacted]	
40	**Rate Change as Requested**							[redacted]	[redacted]	
41	Change in Distribution Revenue	$ 186,945,938	$ 102,458,038	$ 2,080,000	$ 61,580,000	$ 4,040,000	$ 7,850,000	[redacted]	[redacted]	$ 3,060,000
42	Requested Distribution Revenue	$ 729,814,706	$ 386,034,743	$ 8,449,034	$ 241,150,595	$ 15,163,447	$ 33,234,277	[redacted]	[redacted]	$ 20,893,311
43	Requested Distribution Revenue Inc/(Dec)	34.44%	36.13%	32.66%	34.29%	36.32%	30.92%	[redacted]	[redacted]	17.16%
44	Requested Net Operating Income	$201,676,486	$98,185,287	$2,360,843	$73,132,175	$4,176,050	$9,803,556	[redacted]	[redacted]	$4,169,409
45	Requested Rate of Return	7.76%	6.74%	8.76%	8.62%	7.73%	15.97%	[redacted]	[redacted]	3.19%
46	Requested Unitized ROR	1.00	0.87	1.13	1.11	1 00	2 06	[redacted]	[redacted]	0.41

1. FERC 404, Amortizations are included in line 7, Total Amortization Expense

REDACTED

Jersey Central Power & Light
Proposed COSS Revenues
Test Year: July 2019 - June 2020
JCP&L's Proposed Alternative COSS

Line	Description	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
1	Distribution Revenues	$542,868,768	$283,576,706	$6,369,034	$179,570,595	$11,123,447	$25,384,277	[redacted]	[redacted]	$17,833,311
2	Other Operating Revenues	$15,275,018	$9,391,377	$171,874	$4,514,854	$243,204	$364,707	[redacted]	[redacted]	$726,050
3	**Total Operating Revenues**	**$558,143,786**	**$292,968,083**	**$6,540,908**	**$184,085,449**	**$11,366,651**	**$25,748,984**	[redacted]	[redacted]	**$18,559,362**

Jersey Central Power & Light
Other Operating Revenues
Test Year: July 2019 - June 2020
JCP&L's Proposed Alternative COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
REV	Rev - Retail Distribution	Total			$542,868,768	$283,576,706	$6,369,034	$179,570,595	$11,123,447	$25,384,277	[redacted]		$17,833,311
		Customer	DIST-REV-CUST	DIST-REV-CUST	$41,918,982	$30,980,844	$886,940	$9,291,578	$94,289	$250,047			$0
		Demand	DIST-REV-DMD	DIST-REV-DMD	$150,980,629	$0	$0	$95,229,974	$8,719,365	$19,685,757			$12,839,173
		Energy	DIST-REV-NRG	DIST-REV-NRG	$349,969,157	$252,595,861	$5,482,095	$75,049,042	$2,309,794	$5,448,473			$4,994,139
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
450	Rev - Elec Frft Discount	Total			$2,247,882	$347	$0	$1,833,683	$65,385	$234,858			$293,510
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	LATEPAY	$2,247,882	$347	$0	$1,833,683	$65,385	$234,858			$293,510
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
451	Rev - Misc Service	Total			$5,157,789	$4,256,421	$40,846	$687,062	$54,613	$15,742			$62,234
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	ALL451	$5,157,789	$4,256,421	$40,846	$687,062	$54,613	$15,742			$62,234
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
454	Rev - Rent from Elec Prpty	Total			$6,481,819	$3,741,360	$66,929	$2,022,529	$129,204	$128,872			$380,173
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$756,013	$585,466	$11,667	$134,843	$1,279	$10,007			$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$4,867,460	$2,704,472	$44,734	$1,556,695	$101,598	$85,513			$374,448
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$858,345	$451,422	$10,528	$330,991	$26,328	$33,352			$5,725
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
456PG	Other Elec Revs - Pwr Guard	Total			$1,655,608	$1,517,831	$67,438	$70,339	$0	$0			$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	PWRGD	$1,655,608	$1,517,831	$67,438	$70,339	$0	$0			$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
REV-DIST	Distribution Revenues	Total			$542,868,768	$283,576,706	$6,369,034	$179,570,595	$11,123,447	$25,384,277			$17,833,311
		Customer			$41,918,982	$30,980,844	$886,940	$9,291,578	$94,289	$250,047			$0
		Demand			$150,980,629	$0	$0	$95,229,974	$8,719,365	$19,685,757			$12,839,173
		Energy			$349,969,157	$252,595,861	$5,482,095	$75,049,042	$2,309,794	$5,448,473			$4,994,139
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
450,451,456	Other Operating Revs	Total			$15,543,099	$9,515,959	$175,214	$4,613,612	$249,202	$379,472			$735,918
		Customer			$756,013	$585,466	$11,667	$134,843	$1,279	$10,007			$0
		Demand			$13,928,740	$8,479,071	$153,018	$4,147,778	$221,596	$336,113			$730,193
		Energy			$858,345	$451,422	$10,528	$330,991	$26,328	$33,352			$5,725
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-REV	Adjs to Revenue	Total			($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)			($9,867)
		Customer			$0	$0	$0	$0	$0	$0			$0
		Demand			($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)			($9,867)
		Energy			$0	$0	$0	$0	$0	$0			$0
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
ADJ-TOTREV	Total Adj Revenues	Total			$558,143,786	$292,968,083	$6,540,908	$184,085,449	$11,366,651	$25,748,984			$18,559,362
		Customer			$42,674,996	$31,566,310	$898,607	$9,426,421	$95,567	$260,054			$0
		Demand			$164,641,287	$8,354,490	$149,679	$99,278,994	$8,934,962	$20,007,105			$13,559,498
		Energy			$350,827,503	$253,047,284	$5,492,623	$75,380,033	$2,336,121	$5,481,825			$4,999,864

REDACTED

Jersey Central Power & Light
Total Operation & Maintenance Expenses
Test Year July 2019 - June 2020
JCP&L's Proposed Alternative COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
524	Misc Nuclear Pwr Exp	Total			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
580P	OP Supv & Eng - PRI	Total			$26,941	$15,179	$260	$8,886	$621	$1,795			$200
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$21,357	$12,399	$195	$6,848	$459	$1,291			$165
		Energy	AE-PRI-NRG	NRG-PRI	$5,584	$2,780	$65	$2,038	$162	$504			$35
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
580S	OP Supv & Eng - SEC	Total			$62,338	$37,635	$643	$22,024	$1,539	$0			$497
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$49,826	$30,789	$483	$17,004	$1,140	$0			$410
		Energy	AE-SEC-NRG	NRG-SEC	$12,512	$6,846	$160	$5,020	$399	$0			$87
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
581	Load Dispatching	Total			$1,283,749	$723,289	$12,366	$423,433	$29,592	$85,522			$9,546
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$1,017,669	$590,825	$9,276	$326,308	$21,867	$61,526			$7,866
		Energy	AE-PRI-NRG	NRG-PRI	$266,080	$132,464	$3,089	$97,125	$7,726	$23,996			$1,680
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
582P	Station Exp	Total			$586,634	$330,521	$5,651	$193,496	$13,523	$39,081			$4,362
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$465,044	$269,989	$4,239	$149,113	$9,992	$28,116			$3,595
		Energy	AE-PRI-NRG	NRG-PRI	$121,590	$60,532	$1,412	$44,383	$3,530	$10,966			$768
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
582S	Station Exp	Total			$0	$0	$0	$0	$0	$0			$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$0	$0	$0	$0	$0	$0			$0
		Energy	AE-SEC-NRG	NRG-SEC	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
583P	OH Line Exp	Total			$422,381	$237,977	$4,069	$139,318	$9,737	$28,139			$3,141
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$334,835	$194,394	$3,052	$107,362	$7,195	$20,243			$2,588
		Energy	AE-PRI-NRG	NRG-PRI	$87,546	$43,583	$1,016	$31,956	$2,542	$7,895			$553
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
583S	OH Line Exp	Total			$964,470	$582,277	$9,949	$340,751	$23,808	$0			$7,686
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$770,891	$476,354	$7,479	$263,086	$17,630	$0			$6,342
		Energy	AE-SEC-NRG	NRG-SEC	$193,579	$105,923	$2,470	$77,665	$6,178	$0			$1,343
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
584P	UG Line Exp	Total			$1,026,441	$578,317	$9,887	$338,562	$23,661	$68,381			$7,633
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$813,693	$472,403	$7,417	$260,904	$17,484	$49,194			$6,290
		Energy	AE-PRI-NRG	NRG-PRI	$212,748	$105,914	$2,470	$77,658	$6,177	$19,187			$1,343
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
584S	UG Line Exp	Total			$2,343,791	$1,415,010	$24,179	$828,070	$57,856	$0			$18,677
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$1,873,369	$1,157,603	$18,175	$639,334	$42,844	$0			$15,413
		Energy	AE-SEC-NRG	NRG-SEC	$470,423	$257,407	$6,003	$188,735	$15,012	$0			$3,264

REDACTED

Jersey Central Power & Light
Total Operation & Maintenance Expenses
Test Year July 2019 - June 2020
JCP&L's Proposed Alternative COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
585	St Lt & Signal Sys Exp	Total			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP		LTG
586	Meter Exp	Total			$1,124,469	$659,292	$35,042	$307,206	$12,032	$48,763		$0
		Customer	MTR-CUST	CUST-MTR	$913,953	$632,683	$23,547	$142,856	$3,971	$48,763		$0
		Demand	MTR-DMD	DMD-MTR	$210,516	$26,610	$11,495	$164,350	$8,061	$0		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0		$0

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP		LTG
588	Misc Exp	Total			$17,308,525	$9,539,946	$167,051	$5,706,281	$386,706	$359,317		$1,149,224
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0		$0
		Demand	DIST-CLA-DMD	DIST-PLT-DMD	$14,713,834	$8,175,342	$135,227	$4,705,729	$307,120	$258,498		$1,131,918
		Energy	DIST-CLA-NRG	DIST-PLT-NRG	$2,594,690	$1,364,604	$31,825	$1,000,552	$79,586	$100,819		$17,306

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP		LTG
589P	Rent-PRI	Total			$1,864,096	$1,050,268	$17,956	$614,855	$42,970	$124,185		$13,862
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0		$0
		Demand	AE-PRI-DMD	DMD-PRI	$1,477,728	$857,921	$13,470	$473,822	$31,752	$89,340		$11,423
		Energy	AE-PRI-NRG	NRG-PRI	$386,367	$192,347	$4,486	$141,032	$11,218	$34,844		$2,439

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP		LTG
589S	Rent-SEC	Total			$4,313,186	$2,603,987	$44,495	$1,523,864	$106,470	$0		$34,371
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0		$0
		Demand	AE-SEC-DMD	DMD-SEC	$3,447,486	$2,130,290	$33,447	$1,176,541	$78,843	$0		$28,364
		Energy	AE-SEC-NRG	NRG-SEC	$865,700	$473,696	$11,047	$347,322	$27,627	$0		$6,007

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP		LTG
590P	Maint Supv & Engr - PRI	Total			$488,102	$275,006	$4,702	$160,996	$11,251	$32,517		$3,630
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0		$0
		Demand	AE-PRI-DMD	DMD-PRI	$386,934	$224,641	$3,527	$124,067	$8,314	$23,393		$2,991
		Energy	AE-PRI-NRG	NRG-PRI	$101,168	$50,365	$1,175	$36,928	$2,937	$9,124		$639

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP		LTG
590S	Maint Supv & Engr - SEC	Total			$1,129,382	$681,838	$11,651	$399,014	$27,879	$0		$9,000
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0		$0
		Demand	AE-SEC-DMD	DMD-SEC	$902,703	$557,804	$8,758	$308,070	$20,645	$0		$7,427
		Energy	AE-SEC-NRG	NRG-SEC	$226,678	$124,034	$2,893	$90,944	$7,234	$0		$1,573

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP		LTG
591	Maint of Structures	Total			$119,074	$67,088	$1,147	$39,275	$2,745	$7,933		$885
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0		$0
		Demand	AE-PRI-DMD	DMD-PRI	$94,393	$54,802	$860	$30,267	$2,028	$5,707		$730
		Energy	AE-PRI-NRG	NRG-PRI	$24,680	$12,287	$287	$9,009	$717	$2,226		$156

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP		LTG
592P	Maint of Station Equip - PRI	Total			$10,654,296	$6,002,839	$102,628	$3,514,221	$245,598	$709,781		$79,229
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0		$0
		Demand	AE-PRI-DMD	DMD-PRI	$8,446,003	$4,903,472	$76,989	$2,708,146	$181,481	$510,628		$65,287
		Energy	AE-PRI-NRG	NRG-PRI	$2,208,293	$1,099,367	$25,639	$806,075	$64,117	$199,153		$13,942

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP		LTG
592S	Maint of Station Equip - SEC	Total			$0	$0	$0	$0	$0	$0		$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0		$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0		$0

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
593P	Maint of OH Lines - PRI	Total			$11,176,107	$6,296,837	$107,654	$3,686,336	$257,626	$744,544	[redacted]	[redacted]	$83,109
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$8,859,659	$5,143,627	$80,760	$2,840,782	$190,369	$535,637	[redacted]	[redacted]	$68,484
		Energy	AE-PRI-NRG	NRG-PRI	$2,316,448	$1,153,210	$26,895	$845,554	$67,257	$208,907	[redacted]	[redacted]	$14,625
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
593S	Maint of OH Lines - SEC	Total			$25,519,693	$15,406,925	$263,261	$9,016,197	$629,949	$0	[redacted]	[redacted]	$203,362
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$20,397,633	$12,604,222	$197,898	$6,961,205	$466,491	$0	[redacted]	[redacted]	$167,818
		Energy	AE-SEC-NRG	NRG-SEC	$5,122,060	$2,802,703	$65,363	$2,054,992	$163,458	$0	[redacted]	[redacted]	$35,544
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
594P	Maint of UG Lines - PRI	Total			$1,095,515	$617,234	$10,553	$361,345	$25,253	$72,982	[redacted]	[redacted]	$8,147
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$868,450	$504,193	$7,916	$278,462	$18,661	$52,505	[redacted]	[redacted]	$6,713
		Energy	AE-PRI-NRG	NRG-PRI	$227,065	$113,041	$2,636	$82,884	$6,593	$20,478	[redacted]	[redacted]	$1,434
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
594S	Maint of UG Lines - SEC	Total			$2,501,515	$1,510,232	$25,806	$883,794	$61,749	$0	[redacted]	[redacted]	$19,934
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$1,999,436	$1,235,503	$19,399	$682,358	$45,727	$0	[redacted]	[redacted]	$16,450
		Energy	AE-SEC-NRG	NRG-SEC	$502,079	$274,729	$6,407	$201,436	$16,023	$0	[redacted]	[redacted]	$3,484
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
595	Maint of Line Trnsfrmrs	Total			$350,274	$216,444	$3,398	$119,540	$8,011	$0	[redacted]	[redacted]	$2,882
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DMD	DMD-SEC	$350,274	$216,444	$3,398	$119,540	$8,011	$0	[redacted]	[redacted]	$2,882
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
596	Maint of St Lt & Signal Sys	Total			$3,006,789	$0	$0	$0	$0	$0	[redacted]	[redacted]	$3,006,789
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DMD	DMD-LTG	$3,006,789	$0	$0	$0	$0	$0	[redacted]	[redacted]	$3,006,789
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
597	Maint of Meters	Total			$4,870,664	$2,855,741	$151,786	$1,330,670	$52,118	$211,218	[redacted]	[redacted]	$0
		Customer	MTR-CUST	CUST-MTR	$3,958,810	$2,740,481	$101,995	$618,784	$17,201	$211,218	[redacted]	[redacted]	$0
		Demand	MTR-DMD	DMD-MTR	$911,854	$115,261	$49,791	$711,886	$34,917	$0	[redacted]	[redacted]	$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
598	Maint of Misc Dist Plant	Total			$1,578,429	$869,983	$15,234	$520,377	$35,265	$32,767	[redacted]	[redacted]	$104,802
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DIST-CLA-DMD	DIST-PLT-DMD	$1,341,809	$745,540	$12,332	$429,133	$28,007	$23,573	[redacted]	[redacted]	$103,224
		Energy	DIST-CLA-NRG	DIST-PLT-NRG	$236,619	$124,443	$2,902	$91,244	$7,258	$9,194	[redacted]	[redacted]	$1,578
Subtotal	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
Prod O&M	Production O&M Expense	Total			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Customer			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Subtotal	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
Dist O&M	Distribution O&M Expense	Total			$93,816,859	$52,573,867	$1,029,365	$30,478,511	$2,065,958	$2,566,925	[redacted]	[redacted]	$4,770,968
		Customer			$4,872,763	$3,373,163	$125,542	$761,639	$21,173	$259,981	[redacted]	[redacted]	$0
		Demand			$72,762,186	$40,700,427	$705,585	$23,484,318	$1,549,036	$1,659,653	[redacted]	[redacted]	$4,663,167
		Energy			$16,181,910	$8,500,276	$198,239	$6,232,553	$495,749	$647,292	[redacted]	[redacted]	$107,801
Subtotal	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTD&PO&M	Total Distribution O&M	Total			$93,816,859	$52,573,867	$1,029,365	$30,478,511	$2,065,958	$2,566,925	[redacted]	[redacted]	$4,770,968
		Customer			$4,872,763	$3,373,163	$125,542	$761,639	$21,173	$259,981	[redacted]	[redacted]	$0
		Demand			$72,762,186	$40,700,427	$705,585	$23,484,318	$1,549,036	$1,659,653	[redacted]	[redacted]	$4,663,167
		Energy			$16,181,910	$8,500,276	$198,239	$6,232,553	$495,749	$647,292	[redacted]	[redacted]	$107,801

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
901	Supervision	Total			$38,021	$30,166	$605	$6,953	$94	$57	[redacted]	[redacted]	$99
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NRG	ALL901	$38,021	$30,166	$605	$6,953	$94	$57	[redacted]	[redacted]	$99
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
902	Meter Reading Exp	Total			$14,235,371	$8,346,404	$443,620	$3,889,115	$152,324	$617,322	[redacted]	[redacted]	$0
		Customer	MTR-CUST	CUST-MTR	$11,570,317	$8,009,535	$298,097	$1,808,503	$50,274	$617,322	[redacted]	[redacted]	$0
		Demand	MTR-DMD	DMD-MTR	$2,665,054	$336,869	$145,523	$2,080,612	$102,050	$0	[redacted]	[redacted]	$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
903	Cust Records & Collect Exp	Total			$14,453,393	$8,474,233	$450,414	$3,948,679	$154,657	$626,776	[redacted]	[redacted]	$0
		Customer	MTR-CUST	CUST-MTR	$11,747,522	$8,132,205	$302,663	$1,836,202	$51,044	$626,776	[redacted]	[redacted]	$0
		Demand	MTR-DMD	DMD-MTR	$2,705,870	$342,028	$147,752	$2,112,477	$103,613	$0	[redacted]	[redacted]	$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
904	Cust Uncollect Exp	Total			$119,609	$53,881	$1,257	$39,507	$3,142	$9,761	[redacted]	[redacted]	$683
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NRG	NRG-All	$119,609	$53,881	$1,257	$39,507	$3,142	$9,761	[redacted]	[redacted]	$683
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
905	Misc Cust Acct Exp	Total			$1,436,938	$1,140,084	$22,867	$262,797	$3,558	$2,142	[redacted]	[redacted]	$3,757
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NRG	ALL905	$1,436,938	$1,140,084	$22,867	$262,797	$3,558	$2,142	[redacted]	[redacted]	$3,757
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
907	Supervision	Total			$368,340	$207,530	$3,548	$121,494	$8,491	$24,539	[redacted]	[redacted]	$2,739
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$291,995	$169,523	$2,662	$93,626	$6,274	$17,653	[redacted]	[redacted]	$2,257
		Energy	AE-PRI-NRG	NRG-PRI	$76,345	$38,007	$886	$27,868	$2,217	$6,885	[redacted]	[redacted]	$482
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
908	Cust Assist Exp	Total			$1,214,314	$684,168	$11,697	$400,530	$27,992	$80,897	[redacted]	[redacted]	$9,030
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$962,625	$558,869	$8,775	$308,658	$20,684	$58,198	[redacted]	[redacted]	$7,441
		Energy	AE-PRI-NRG	NRG-PRI	$251,688	$125,299	$2,922	$91,872	$7,308	$22,698	[redacted]	[redacted]	$1,589
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
909	Info & Instrctnl Advertising	Total			$2,400	$1,352	$23	$792	$55	$160	[redacted]	[redacted]	$18
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$1,903	$1,105	$17	$610	$41	$115	[redacted]	[redacted]	$15
		Energy	AE-PRI-NRG	NRG-PRI	$497	$248	$6	$182	$14	$45	[redacted]	[redacted]	$3
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
910	Misc Cust Srvc & Info Exp	Total			$9,383,308	$5,286,740	$90,385	$3,094,998	$216,299	$625,109	[redacted]	[redacted]	$69,778
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$7,438,450	$4,318,520	$67,805	$2,385,082	$159,831	$449,713	[redacted]	[redacted]	$57,499
		Energy	AE-PRI-NRG	NRG-PRI	$1,944,858	$968,220	$22,580	$709,916	$56,468	$175,396	[redacted]	[redacted]	$12,279
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
911	Sales Exp	Total			$56,383	$31,767	$543	$18,598	$1,300	$3,756	[redacted]	[redacted]	$419
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	$44,697	$25,950	$407	$14,332	$960	$2,702	[redacted]	[redacted]	$346
		Energy	AE-PRI-NRG	NRG-PRI	$11,686	$5,818	$136	$4,266	$339	$1,054	[redacted]	[redacted]	$74

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920	A&G Salaries	Total			$850,366	$478,280	$8,172	$279,875	$19,554	$56,500	[redacted]		$6,313
		Customer	A&G-GT-CUST	CUST-GTA&G	$1,673	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$674,112	$391,368	$6,145	$216,149	$14,485	$40,755			$5,211
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$174,581	$86,912	$2,027	$63,726	$5,069	$15,744			$1,102
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
921	Office Supplies & Exp	Total			$1,085,146	$610,330	$10,428	$357,146	$24,952	$72,099			$8,056
		Customer	A&G-GT-CUST	CUST-GTA&G	$2,135	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$860,230	$499,421	$7,841	$275,826	$18,484	$52,008			$6,650
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$222,781	$110,908	$2,587	$81,320	$6,468	$20,091			$1,407
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
922	Admin Exp Trnsfr Credit	Total			$0	$0	$0	$0	$0	$0			$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
923	Outside Services	Total			$32,961,974	$18,539,139	$316,754	$10,848,534	$757,940	$2,190,055			$244,707
		Customer	A&G-GT-CUST	CUST-GTA&G	$64,844	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$26,130,016	$15,170,230	$238,186	$8,378,390	$561,460	$1,579,767			$201,983
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$6,767,114	$3,368,910	$78,568	$2,470,144	$196,480	$610,287			$42,725
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
924	Property Insurance	Total			$253,345	$142,491	$2,435	$83,382	$5,826	$16,833			$1,881
		Customer	A&G-GT-CUST	CUST-GTA&G	$498	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$200,835	$116,598	$1,831	$64,396	$4,315	$12,142			$1,552
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$52,012	$25,893	$604	$18,985	$1,510	$4,691			$328
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
925	Injuries & Damages	Total			$3,344,187	$1,880,905	$32,137	$1,100,648	$76,898	$222,194			$24,827
		Customer	A&G-GT-CUST	CUST-GTA&G	$6,579	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$2,651,045	$1,539,109	$24,165	$850,037	$56,963	$160,277			$20,492
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$686,564	$341,796	$7,971	$250,611	$19,934	$61,917			$4,335
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
926	Pensions & Benefits	Total			$44,294,361	$24,912,930	$425,655	$14,578,280	$1,018,522	$2,942,999			$328,838
		Customer	A&G-GT-CUST	CUST-GTA&G	$87,138	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$35,113,564	$20,385,783	$320,075	$11,258,895	$754,491	$2,122,894			$271,425
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$9,093,660	$4,527,147	$105,580	$3,319,384	$264,030	$820,105			$57,413
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
928	Regulatory Comms Exp	Total			$4,483,645	$2,521,782	$43,086	$1,475,669	$103,099	$297,902			$33,286
		Customer	A&G-GT-CUST	CUST-GTA&G	$8,820	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$3,554,330	$2,063,527	$32,399	$1,139,669	$76,373	$214,887			$27,475
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$920,495	$458,255	$10,687	$336,001	$26,726	$83,014			$5,812

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
930.1	Gen Advertising Exp	Total			$996,585	$560,520	$9,577	$327,999	$22,916	$66,215	[redacted]		$7,399
		Customer	A&G-GT-CUST	CUST-GTA&G	$1,961	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$790,025	$458,663	$7,201	$253,316	$16,975	$47,763	[redacted]		$6,107
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$204,600	$101,857	$2,375	$74,683	$5,940	$18,452	[redacted]		$1,292

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
930.2	Misc Gen Exp	Total			$2,279,321	$1,281,982	$21,904	$750,176	$52,412	$151,442	[redacted]		$16,922
		Customer	A&G-GT-CUST	CUST-GTA&G	$4,484	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$1,806,891	$1,049,022	$16,471	$579,366	$38,825	$109,241	[redacted]		$13,967
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$467,946	$232,960	$5,433	$170,811	$13,587	$42,201	[redacted]		$2,954

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
931	Rents	Total			$2,510,095	$1,411,778	$24,121	$826,129	$57,718	$166,775	[redacted]		$18,635
		Customer	A&G-GT-CUST	CUST-GTA&G	$4,938	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$1,989,833	$1,155,232	$18,138	$638,025	$42,756	$120,301	[redacted]		$15,381
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$515,324	$256,547	$5,983	$188,105	$14,962	$46,474	[redacted]		$3,254

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
935	Maint of Gen Plant	Total			$2,562,438	$1,441,218	$24,624	$843,357	$58,922	$170,253	[redacted]		$19,023
		Customer	A&G-GT-CUST	CUST-GTA&G	$5,041	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$2,031,327	$1,179,322	$18,516	$651,329	$43,647	$122,810	[redacted]		$15,702
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$526,070	$261,896	$6,108	$192,027	$15,274	$47,443	[redacted]		$3,321

Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
CA-EXP	Customer Accts Exp	Total			$30,283,331	$18,044,768	$918,764	$8,147,051	$313,776	$1,256,058	[redacted]		$4,540
		Customer			$23,317,839	$16,141,739	$600,760	$3,644,705	$101,318	$1,244,098	[redacted]		$0
		Demand			$5,370,924	$678,898	$293,274	$4,193,089	$205,663	$0	[redacted]		$0
		Energy			$1,594,568	$1,224,131	$24,729	$309,257	$6,795	$11,960	[redacted]		$4,540

Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
CS&I-EXP	Cust Service & Info Exp	Total			$10,968,363	$6,179,790	$105,653	$3,617,813	$252,837	$730,704	[redacted]		$81,565
		Customer			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			$8,694,974	$5,048,016	$79,258	$2,787,977	$186,830	$525,680	[redacted]		$67,211
		Energy			$2,273,389	$1,131,774	$26,395	$829,837	$66,007	$205,024	[redacted]		$14,353

Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
SALES-EXP	Sales Exp	Total			$56,383	$31,767	$543	$18,598	$1,300	$3,756	[redacted]		$419
		Customer			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			$44,697	$25,950	$407	$14,332	$960	$2,702	[redacted]		$346
		Energy			$11,686	$5,818	$136	$4,266	$339	$1,054	[redacted]		$74

Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
A&G-EXP	A&G Exp	Total			$95,621,463	$53,781,356	$918,892	$31,471,194	$2,198,757	$6,353,267	[redacted]		$709,887
		Customer			$188,111	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			$75,802,207	$44,008,274	$690,970	$24,305,398	$1,628,776	$4,582,846	[redacted]		$585,944
		Energy			$19,631,146	$9,773,082	$227,922	$7,165,797	$569,981	$1,770,421	[redacted]		$123,943

Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
TOTCSA&G	Total Cust Srvc and A&G Exp	Total			$136,929,540	$78,037,682	$1,943,852	$43,254,656	$2,766,669	$8,343,786	[redacted]		$796,411
		Customer			$23,505,950	$16,141,739	$600,760	$3,644,705	$101,318	$1,244,098	[redacted]		$0
		Demand			$89,912,802	$49,761,137	$1,063,910	$31,300,795	$2,022,229	$5,111,229	[redacted]		$653,501
		Energy			$23,510,789	$12,134,805	$279,182	$8,309,156	$643,122	$1,988,458	[redacted]		$142,910

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
403-360P	Land & Land Rights - PRI - Deprec Exp	Total			$79,214	$44,631	$763	$26,128	$1,826	$5,277	[redacted]		$589
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$62,796	$36,457	$572	$20,135	$1,349	$3,796			$485
		Energy	AE-PRI-NRG	NRG-PRI	$16,419	$8,174	$191	$5,993	$477	$1,481			$104
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-360S	Land & Land Rights - SEC - Deprec Exp	Total			$113,521	$68,536	$1,171	$40,107	$2,802	$0			$905
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$90,736	$56,068	$880	$30,966	$2,075	$0			$747
		Energy	AE-SEC-NRG	NRG-SEC	$22,785	$12,467	$291	$9,141	$727	$0			$158
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-361P	Struct & Impmnts -PRI - Deprec Exp	Total			$427,297	$240,748	$4,116	$140,940	$9,850	$28,466			$3,178
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$338,732	$196,657	$3,088	$108,612	$7,278	$20,479			$2,618
		Energy	AE-PRI-NRG	NRG-PRI	$88,565	$44,091	$1,028	$32,328	$2,571	$7,987			$559
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-361S	Struct & Impmnts -SEC - Deprec Exp	Total			$247,738	$149,566	$2,556	$87,527	$6,115	$0			$1,974
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$198,014	$122,358	$1,921	$67,577	$4,529	$0			$1,629
		Energy	AE-SEC-NRG	NRG-SEC	$49,723	$27,208	$635	$19,949	$1,587	$0			$345
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-362P	Station Equip - PRI - Deprec Exp	Total			$7,538,342	$4,247,249	$72,613	$2,486,453	$173,770	$502,199			$56,058
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$5,975,886	$3,469,403	$54,473	$1,916,122	$128,405	$361,290			$46,193
		Energy	AE-PRI-NRG	NRG-PRI	$1,562,456	$777,846	$18,140	$570,331	$45,365	$140,909			$9,865
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-362S	Station Equip - SEC - Deprec Exp	Total			$0	$0	$0	$0	$0	$0			$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$0	$0	$0	$0	$0	$0			$0
		Energy	AE-SEC-NRG	NRG-SEC	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-364P	Poles, Towers & Fixt - PRI - Deprec Exp	Total			$5,530,229	$3,115,839	$53,270	$1,824,095	$127,480	$368,420			$41,125
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$4,383,990	$2,545,201	$39,962	$1,405,693	$94,200	$265,047			$33,888
		Energy	AE-PRI-NRG	NRG-PRI	$1,146,239	$570,638	$13,308	$418,402	$33,281	$103,373			$7,237
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-364S	Poles, Towers & Fixt - SEC - Deprec Exp	Total			$12,627,809	$7,623,748	$130,268	$4,461,449	$311,715	$0			$100,629
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	$10,093,281	$6,236,898	$97,925	$3,444,586	$230,832	$0			$83,041
		Energy	AE-SEC-NRG	NRG-SEC	$2,534,529	$1,386,851	$32,343	$1,016,863	$80,883	$0			$17,588

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
403-365P	OH Cond & Dev - PRI - Deprec Exp	Total			$8,196,200	$4,617,900	$78,950	$2,703,441	$188,935	$546,025	[redacted]		$60,950
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$6,497,391	$3,772,172	$59,227	$2,083,339	$139,611	$392,819	[redacted]		$50,224
		Energy	AE-PRI-NRG	NRG-PRI	$1,698,809	$845,727	$19,724	$620,102	$49,324	$153,206	[redacted]		$10,726

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-365S	OH Cond & Dev - SEC - Deprec Exp	Total			$18,715,329	$11,298,948	$193,067	$6,612,191	$461,984	$0	[redacted]		$149,139
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$14,958,974	$9,243,535	$145,132	$5,105,126	$342,109	$0	[redacted]		$123,072
		Energy	AE-SEC-NRG	NRG-SEC	$3,756,355	$2,055,413	$47,935	$1,507,065	$119,875	$0	[redacted]		$26,067

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-366P	UG Conduit - PRI - Deprec Exp	Total			$457,251	$257,624	$4,404	$150,820	$10,540	$30,462	[redacted]		$3,400
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$362,478	$210,443	$3,304	$116,226	$7,789	$21,915	[redacted]		$2,802
		Energy	AE-PRI-NRG	NRG-PRI	$94,773	$47,182	$1,100	$34,594	$2,752	$8,547	[redacted]		$598

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-366S	UG Conduit - SEC - Deprec Exp	Total			$1,044,095	$630,348	$10,771	$368,882	$25,773	$0	[redacted]		$8,320
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$834,534	$515,680	$8,097	$284,806	$19,086	$0	[redacted]		$6,866
		Energy	AE-SEC-NRG	NRG-SEC	$209,560	$114,668	$2,674	$84,076	$6,688	$0	[redacted]		$1,454

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-367P	UG Cond & Dev - PRI - Deprec Exp	Total			$3,568,635	$2,010,639	$34,375	$1,177,081	$82,262	$237,740	[redacted]		$26,538
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$2,828,972	$1,642,408	$25,787	$907,088	$60,787	$171,034	[redacted]		$21,868
		Energy	AE-PRI-NRG	NRG-PRI	$739,663	$368,231	$8,588	$269,993	$21,476	$66,706	[redacted]		$4,670

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-367S	UG Cond & Dev - SEC - Deprec Exp	Total			$8,148,675	$4,919,575	$84,062	$2,878,956	$201,148	$0	[redacted]		$64,935
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$6,513,154	$4,024,645	$63,191	$2,222,778	$148,955	$0	[redacted]		$53,586
		Energy	AE-SEC-NRG	NRG-SEC	$1,635,521	$894,929	$20,871	$656,178	$52,194	$0	[redacted]		$11,350

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-368	Line Transformers - Deprec Exp	Total			$21,448,336	$13,253,478	$208,092	$7,319,784	$490,520	$0	[redacted]		$176,462
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DMD	DMD-SEC	$21,448,336	$13,253,478	$208,092	$7,319,784	$490,520	$0	[redacted]		$176,462
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-369	Services - Deprec Exp	Total			$6,330,609	$5,450,158	$84,148	$784,544	$8,925	$0	[redacted]		$2,834
		Customer	SRVC-CUST	CUST-SVCS	$5,986,117	$5,237,288	$80,806	$666,977	$1,046	$0	[redacted]		$0
		Demand	SRVC-DMD	DMD-SEC	$344,492	$212,870	$3,342	$117,567	$7,878	$0	[redacted]		$2,834
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-370	Meters - Deprec Exp	Total			$10,302,747	$6,040,650	$321,067	$2,814,719	$110,243	$446,782	[redacted]		$0
		Customer	MTR-CUST	CUST-MTR	$8,373,934	$5,796,843	$215,746	$1,308,891	$36,386	$446,782	[redacted]		$0
		Demand	MTR-DMD	DMD-MTR	$1,928,813	$243,807	$105,321	$1,505,828	$73,858	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
403-371	Install on Cust Premise - Deprec Exp	Total			$910,175	$0	$0	$0	$0	$0	[redacted]		$910,175
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	DMD-LTG	$910,175	$0	$0	$0	$0	$0			$910,175
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-373	St Lt & Signal Sys - Deprec Exp	Total			$7,189,520	$0	$0	$0	$0	$0			$7,189,520
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	DMD-LTG	$7,189,520	$0	$0	$0	$0	$0			$7,189,520
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-374	Asset Retirement Costs	Total			$850	$479	$8	$280	$20	$57			$6
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	$674	$391	$6	$216	$14	$41			$5
		Energy	AE-PRI-NRG	NRG-PRI	$176	$88	$2	$64	$5	$16			$1
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-389	Land & Land Rights - Deprec Exp	Total			$377	$196	$3	$115	$8	$23			$3
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$297	$160	$3	$88	$6	$17			$2
		Energy	AE-ALL-NRG	NRG-All	$80	$36	$1	$27	$2	$7			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-390	Struct & Impmnts - Deprec Exp	Total			$1,494,037	$778,151	$13,310	$455,704	$31,855	$92,075			$10,270
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$1,175,799	$634,792	$9,967	$350,590	$23,494	$66,105			$8,452
		Energy	AE-ALL-NRG	NRG-All	$318,238	$143,359	$3,343	$105,113	$8,361	$25,970			$1,818
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-391	Office Furn & Equip - Deprec Exp	Total			$1,903,796	$991,569	$16,961	$580,686	$40,592	$117,327			$13,087
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$1,498,277	$808,892	$12,700	$446,744	$29,938	$84,235			$10,770
		Energy	AE-ALL-NRG	NRG-All	$405,518	$182,677	$4,260	$133,942	$10,654	$33,092			$2,317
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-392	Transportation Equip - Deprec Exp	Total			$535,910	$279,122	$4,774	$163,461	$11,426	$33,027			$3,684
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$421,759	$227,700	$3,575	$125,757	$8,427	$23,712			$3,032
		Energy	AE-ALL-NRG	NRG-All	$114,152	$51,423	$1,199	$37,704	$2,999	$9,315			$652
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-393	Stores Equip - Deprec Exp	Total			$44,353	$23,101	$395	$13,528	$946	$2,733			$305
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$34,905	$18,845	$296	$10,408	$697	$1,962			$251
		Energy	AE-ALL-NRG	NRG-All	$9,447	$4,256	$99	$3,120	$248	$771			$54
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
403-394	Tools, Shop & Garage Equip - Deprec Exp	Total			$1,215,535	$633,097	$10,829	$370,756	$25,917	$74,911			$8,356
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-ALL-DMD	DMD-ALL	$956,620	$516,461	$8,109	$285,237	$19,115	$53,782			$6,876
		Energy	AE-ALL-NRG	NRG-All	$258,915	$116,636	$2,720	$85,519	$6,802	$21,129			$1,479

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
403-396	Power Operated Equip - Deprec Exp	Total			$16,999	$8,854	$151	$5,185	$362	$1,048	[redacted]		$117
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$13,378	$7,223	$113	$3,989	$267	$752	[redacted]		$96
		Energy	AE-ALL-NRG	NRG-All	$3,621	$1,631	$38	$1,196	$95	$295	[redacted]		$21
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-397	Communication Equip - Deprec Exp	Total			$1,691,857	$881,183	$15,072	$516,042	$36,073	$104,266	[redacted]		$11,630
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$1,331,482	$718,842	$11,286	$397,011	$26,605	$74,857	[redacted]		$9,571
		Energy	AE-ALL-NRG	NRG-All	$360,374	$162,341	$3,786	$119,031	$9,468	$29,408	[redacted]		$2,059
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-398	MISC Equip - Deprec Exp	Total			$17,967	$9,358	$160	$5,480	$383	$1,107	[redacted]		$124
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$14,140	$7,634	$120	$4,216	$283	$795	[redacted]		$102
		Energy	AE-ALL-NRG	NRG-All	$3,827	$1,724	$40	$1,264	$101	$312	[redacted]		$22
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403-399	Other Tangible Property - Deprec Exp	Total			$70,511	$36,725	$628	$21,507	$1,503	$4,345	[redacted]		$485
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$55,492	$29,959	$470	$16,546	$1,109	$3,120	[redacted]		$399
		Energy	AE-ALL-NRG	NRG-All	$15,019	$6,766	$158	$4,961	$395	$1,226	[redacted]		$86
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403 (360-374)	Distribution Plant Depreciation Exp	Total			$112,875,724	$63,969,636	$1,283,693	$33,877,118	$2,213,891	$2,165,371	[redacted]		$8,796,730
		Customer			$14,360,051	$11,034,131	$296,552	$1,975,869	$37,432	$446,782	[redacted]		$0
		Demand			$84,960,275	$45,782,080	$820,313	$26,656,231	$1,759,260	$1,236,380	[redacted]		$8,706,010
		Energy			$13,555,397	$7,153,425	$166,828	$5,245,018	$417,199	$482,208	[redacted]		$90,720
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403 (389-399)	General Plant - Deprec Expense	Total			$6,992,192	$3,641,834	$62,293	$2,132,744	$149,085	$430,919	[redacted]		$48,065
		Customer			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			$5,502,823	$2,970,899	$46,646	$1,640,802	$109,955	$309,378	[redacted]		$39,556
		Energy			$1,489,369	$670,936	$15,647	$491,942	$39,130	$121,542	[redacted]		$8,509
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
403 (360-399)	Total - Unadjusted Deprec Expense	Total			$119,867,916	$67,611,470	$1,345,986	$36,009,862	$2,362,976	$2,596,290	[redacted]		$8,844,795
		Customer			$14,360,051	$11,034,131	$296,552	$1,975,869	$37,432	$446,782	[redacted]		$0
		Demand			$90,463,098	$48,752,979	$866,959	$28,297,034	$1,869,215	$1,545,757	[redacted]		$8,745,566
		Energy			$15,044,766	$7,824,360	$182,475	$5,736,960	$456,329	$603,750	[redacted]		$99,229
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-DEPRC	Adjs to Depreciation Exp	Total			$25,777,280	$14,642,159	$282,416	$7,834,318	$509,866	$544,481	[redacted]		$1,784,161
		Customer	See Adjustments	See Adjustments	$3,063,455	$2,359,400	$58,523	$458,550	$7,154	$79,073	[redacted]		$0
		Demand	See Adjustments	See Adjustments	$19,424,648	$10,566,116	$183,858	$6,117,096	$402,595	$334,727	[redacted]		$1,762,390
		Energy	See Adjustments	See Adjustments	$3,289,176	$1,716,642	$40,035	$1,258,672	$100,117	$130,681	[redacted]		$21,771
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
ADJ-TOTDPREXP	Total Adjusted Depreciation Exp	Total			$145,645,195	$82,253,629	$1,628,402	$43,844,180	$2,872,842	$3,140,771	[redacted]		$10,628,956
		Customer			$17,423,507	$13,393,531	$355,075	$2,434,419	$44,586	$525,856	[redacted]		$0
		Demand			$109,887,746	$59,319,095	$1,050,817	$34,414,130	$2,271,810	$1,880,484	[redacted]		$10,507,957
		Energy			$18,333,942	$9,541,002	$222,510	$6,995,632	$556,446	$734,431	[redacted]		$120,999

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Depreciation & Amortization Expense
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
404	Amort - Ltd Term Elec Prpty	Total			$8,815,151	$5,088,179	$91,023	$2,750,601	$175,715	$175,264	[redacted]	[redacted]	$517,028
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$1,028,164	$796,222	$15,868	$183,384	$1,739	$13,610	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$6,619,654	$3,678,031	$60,838	$2,117,075	$138,171	$116,297	[redacted]	[redacted]	$509,242
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$1,167,334	$613,926	$14,318	$450,141	$35,805	$45,358	[redacted]	[redacted]	$7,786
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
407-TMI/OC	Amort - TMI and OC	Total			$109,008	$49,106	$1,145	$36,005	$2,864	$8,896	[redacted]	[redacted]	$623
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NRG	NRG-ALL	$109,008	$49,106	$1,145	$36,005	$2,864	$8,896	[redacted]	[redacted]	$623
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
407-STRM	Amort - Storm Exp	Total			$25,566,878	$13,316,199	$227,771	$7,798,281	$545,122	$1,575,637	[redacted]	[redacted]	$175,746
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$20,120,999	$10,862,951	$170,558	$5,999,516	$402,045	$1,131,224	[redacted]	[redacted]	$144,634
		Energy	AE-ALL-NRG	NRG-ALL	$5,445,879	$2,453,247	$57,213	$1,798,765	$143,077	$444,413	[redacted]	[redacted]	$31,112
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
407-COR	Amort - Cost of Removal	Total			($3,124,154)	($1,803,288)	($32,259)	($974,833)	($62,275)	($62,115)	[redacted]	[redacted]	($183,239)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($364,389)	($282,187)	($5,624)	($64,993)	($616)	($4,823)	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($2,346,054)	($1,303,521)	($21,561)	($750,307)	($48,969)	($41,216)	[redacted]	[redacted]	($180,479)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($413,712)	($217,580)	($5,074)	($159,533)	($12,690)	($16,075)	[redacted]	[redacted]	($2,759)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
407-ARO	Amort - ARO ACCR & DEP	Total			($9,421,269)	($4,906,954)	($83,933)	($2,873,628)	($200,875)	($580,614)	[redacted]	[redacted]	($64,762)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($7,414,489)	($4,002,944)	($62,850)	($2,210,792)	($148,152)	($416,851)	[redacted]	[redacted]	($53,297)
		Energy	AE-ALL-NRG	NRG-ALL	($2,006,780)	($904,010)	($21,083)	($662,836)	($52,723)	($163,764)	[redacted]	[redacted]	($11,465)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
411.1- Accretion	Accretion Expense	Total			$9,380,189	$4,885,558	$83,567	$2,861,098	$199,999	$578,083	[redacted]	[redacted]	$64,479
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$7,382,160	$3,985,490	$62,576	$2,201,152	$147,506	$415,033	[redacted]	[redacted]	$53,064
		Energy	AE-ALL-NRG	NRG-ALL	$1,998,029	$900,068	$20,991	$659,946	$52,493	$163,050	[redacted]	[redacted]	$11,415
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
404, 407	Amortization Expense	Total			$31,325,803	$16,628,799	$287,314	$9,597,524	$660,551	$1,695,150	[redacted]	[redacted]	$509,876
		Customer			$663,775	$514,035	$10,244	$118,391	$1,123	$8,786	[redacted]	[redacted]	$0
		Demand			$24,362,269	$13,220,007	$209,560	$7,356,645	$490,601	$1,204,487	[redacted]	[redacted]	$473,164
		Energy			$6,299,759	$2,894,757	$67,510	$2,122,487	$168,827	$481,877	[redacted]	[redacted]	$36,711
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-AMORT	Adjs to Amortization Exp	Total			$82,185,866	$43,065,205	$740,415	$25,204,451	$1,760,125	$4,927,060	[redacted]	[redacted]	$589,644
		Customer			$149,455	$103,070	$3,790	$23,284	$636	$7,786	[redacted]	[redacted]	$0
		Demand			$64,611,222	$35,050,289	$552,128	$19,383,088	$1,298,390	$3,531,957	[redacted]	[redacted]	$489,362
		Energy			$17,425,189	$7,911,847	$184,496	$5,798,079	$461,099	$1,387,318	[redacted]	[redacted]	$100,282
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-TOTAMORTEXI	Total Adj Amort Exp	Total			$113,511,669	$59,694,004	$1,027,729	$34,801,975	$2,420,676	$6,622,210	[redacted]	[redacted]	$1,099,520
		Customer			$813,230	$617,105	$14,034	$141,676	$1,759	$16,572	[redacted]	[redacted]	$0
		Demand			$88,973,491	$48,270,295	$761,689	$26,739,733	$1,788,992	$4,736,444	[redacted]	[redacted]	$962,527
		Energy			$23,724,948	$10,806,604	$252,006	$7,920,566	$629,925	$1,869,194	[redacted]	[redacted]	$136,993

Jersey Central Power & Light
Taxes Other Than Income
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
408-PPTYTX	Txs Otr Inc - Property Tax	Total			$4,935,959	$2,826,915	$50,410	$1,537,414	$98,936	$114,550	[redacted]		$269,148
		Customer	RB-PLT-CUST	RB-PLT-CUST	$529,855	$410,326	$8,177	$94,505	$896	$7,014	[redacted]		$0
		Demand	RB-PLT-DMD	RB-PLT-DMD	$3,720,786	$2,062,483	$33,975	$1,183,272	$77,388	$77,328	[redacted]		$264,657
		Energy	RB-PLT-NRG	RB-PLT-NRG	$685,318	$354,106	$8,258	$259,637	$20,652	$30,209	[redacted]		$4,491
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
408-PAY	Txs Otr Inc - Payroll & Unemp	Total			$4,621,369	$2,615,877	$59,547	$1,476,721	$96,787	$218,519	[redacted]		$111,503
		Customer	PAY-CUST	PAY-CUST	$568,366	$390,843	$14,546	$88,250	$2,453	$30,124	[redacted]		$0
		Demand	PAY-DMD	PAY-DMD	$3,258,040	$1,811,756	$35,439	$1,097,231	$71,525	$135,607	[redacted]		$106,482
		Energy	PAY-NRG	PAY-NRG	$794,962	$413,278	$9,562	$291,240	$22,809	$52,789	[redacted]		$5,021
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
TOTTXOTR	Total Taxes Other Than Income	Total			$9,557,328	$5,442,791	$109,958	$3,014,136	$195,723	$333,069	[redacted]		$380,651
		Customer			$1,098,221	$801,169	$22,723	$182,755	$3,349	$37,137	[redacted]		$0
		Demand			$6,978,827	$3,874,240	$69,414	$2,280,504	$148,913	$212,934	[redacted]		$371,139
		Energy			$1,480,280	$767,383	$17,820	$550,877	$43,461	$82,997	[redacted]		$9,512

REDACTED

Jersey Central Power & Light
Plant In Service
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
301	Organization	Total			$45,044	$23,461	$401	$13,739	$960	$2,776	[redacted]	[redacted]	$310
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$35,450	$19,139	$300	$10,570	$708	$1,993	[redacted]	[redacted]	$255
		Energy	AE-ALL-NRG	NRG-ALL	$9,595	$4,322	$101	$3,169	$252	$783	[redacted]	[redacted]	$55
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
302	Franchise and Consents	Total			$15,029	$7,828	$134	$4,584	$320	$926	[redacted]	[redacted]	$103
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$11,828	$6,386	$100	$3,527	$236	$665	[redacted]	[redacted]	$85
		Energy	AE-ALL-NRG	NRG-ALL	$3,201	$1,442	$34	$1,057	$84	$261	[redacted]	[redacted]	$18
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
303	Misc Intangible Plant	Total			$126,008,783	$65,630,147	$1,122,593	$38,434,565	$2,686,687	$7,765,676	[redacted]	[redacted]	$866,181
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$99,168,253	$53,539,085	$840,612	$29,569,184	$1,981,517	$5,575,347	[redacted]	[redacted]	$712,841
		Energy	AE-ALL-NRG	NRG-ALL	$26,840,530	$12,091,063	$281,981	$8,865,382	$705,169	$2,190,329	[redacted]	[redacted]	$153,339
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTINTPLT	Total Intangible PIS	Total			$126,068,856	$65,661,436	$1,123,128	$38,452,889	$2,687,968	$7,769,379	[redacted]	[redacted]	$866,594
		Customer			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand			$99,215,530	$53,564,609	$841,013	$29,583,281	$1,982,462	$5,578,005	[redacted]	[redacted]	$713,181
		Energy			$26,853,326	$12,096,827	$282,115	$8,869,608	$705,506	$2,191,374	[redacted]	[redacted]	$153,412

REDACTED

Jersey Central Power & Light
Plant In Service
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JCP&L's Proposed Alternative COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
360P	Land & Land Rights - PRI	Total			$13,422,285	$7,562,378	$129,290	$4,427,217	$309,404	$894,183	[redacted]		$99,813
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$10,640,276	$6,177,395	$96,991	$3,411,723	$228,630	$643,289	[redacted]		$82,248
		Energy	AE-PRI-NRG	NRG-PRI	$2,782,008	$1,384,983	$32,300	$1,015,494	$80,774	$250,893	[redacted]		$17,564
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
360S	Land & Land Rights - SEC	Total			$19,235,342	$11,612,893	$198,431	$6,795,914	$474,821	$0	[redacted]		$153,283
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$15,374,615	$9,500,370	$149,164	$5,246,974	$351,615	$0	[redacted]		$126,492
		Energy	AE-SEC-NRG	NRG-SEC	$3,860,727	$2,112,524	$49,267	$1,548,940	$123,206	$0	[redacted]		$26,791
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
361P	Struct & Impmnts -PRI	Total			$37,790,169	$21,291,721	$364,015	$12,464,739	$871,120	$2,517,553	[redacted]		$281,021
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$29,957,482	$17,392,331	$273,075	$9,605,637	$643,702	$1,811,168	[redacted]		$231,569
		Energy	AE-PRI-NRG	NRG-PRI	$7,832,688	$3,899,390	$90,939	$2,859,102	$227,418	$706,385	[redacted]		$49,452
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
361S	Struct & Impmnts -SEC	Total			$21,909,940	$13,227,620	$226,023	$7,740,859	$540,843	$0	[redacted]		$174,596
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$17,512,394	$10,821,359	$169,905	$5,976,545	$400,506	$0	[redacted]		$144,080
		Energy	AE-SEC-NRG	NRG-SEC	$4,397,546	$2,406,262	$56,117	$1,764,314	$140,337	$0	[redacted]		$30,516
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
362P	Station Equip - PRI	Total			$527,855,471	$297,404,102	$5,084,581	$174,108,265	$12,167,862	$35,165,344	[redacted]		$3,925,317
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$418,447,998	$242,937,174	$3,814,334	$134,172,147	$8,991,268	$25,298,510	[redacted]		$3,234,565
		Energy	AE-PRI-NRG	NRG-PRI	$109,407,473	$54,466,928	$1,270,247	$39,936,118	$3,176,595	$9,866,834	[redacted]		$690,752
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
362S	Station Equip - SEC	Total			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Energy	AE-SEC-NRG	NRG-SEC	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
364P	Poles, Towers & Fixt - PRI	Total			$229,359,247	$129,225,488	$2,209,308	$75,652,035	$5,287,076	$15,279,745	[redacted]		$1,705,595
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$181,820,447	$105,558,984	$1,657,372	$58,299,335	$3,906,809	$10,992,492	[redacted]		$1,405,456
		Energy	AE-PRI-NRG	NRG-PRI	$47,538,800	$23,666,504	$551,937	$17,352,700	$1,380,267	$4,287,253	[redacted]		$300,140
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
364S	Poles, Towers & Fixt - SEC	Total			$523,722,418	$316,185,310	$5,402,712	$185,032,962	$12,927,986	$0	[redacted]		$4,173,448
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$418,606,052	$258,667,439	$4,061,313	$142,859,840	$9,573,455	$0	[redacted]		$3,444,004
		Energy	AE-SEC-NRG	NRG-SEC	$105,116,367	$57,517,871	$1,341,399	$42,173,123	$3,354,530	$0	[redacted]		$729,444
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
365P	OH Cond & Dev - PRI	Total			$360,555,173	$203,143,840	$3,473,056	$118,925,803	$8,311,339	$24,019,921	[redacted]		$2,681,214
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$285,823,674	$165,939,844	$2,605,406	$91,647,173	$6,141,545	$17,280,314	[redacted]		$2,209,391
		Energy	AE-PRI-NRG	NRG-PRI	$74,731,499	$37,203,996	$867,650	$27,278,629	$2,169,794	$6,739,607	[redacted]		$471,823
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
365S	OH Cond & Dev - SEC	Total			$823,297,205	$497,046,666	$8,493,121	$290,873,783	$20,322,931	$0	[redacted]		$6,560,705
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$658,053,160	$406,627,962	$6,384,428	$224,577,186	$15,049,574	$0	[redacted]		$5,414,011
		Energy	AE-SEC-NRG	NRG-SEC	$165,244,045	$90,418,704	$2,108,693	$66,296,597	$5,273,357	$0	[redacted]		$1,146,693

REDACTED

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
366P	UG Conduit - PRI	Total			$35,696,744	$20,112,244	$343,850	$11,774,242	$822,864	$2,378,091	[redacted]		$265,453
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$28,297,956	$16,428,864	$257,948	$9,073,523	$608,043	$1,710,837	[redacted]		$218,741
		Energy	AE-PRI-NRG	NRG-PRI	$7,398,788	$3,683,379	$85,902	$2,700,719	$214,820	$667,254	[redacted]		$46,713
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
366S	UG Conduit - SEC	Total			$81,510,491	$49,210,076	$840,861	$28,797,942	$2,012,071	$0	[redacted]		$649,542
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$65,150,514	$40,258,177	$632,090	$22,234,251	$1,489,982	$0	[redacted]		$536,014
		Energy	AE-SEC-NRG	NRG-SEC	$16,359,977	$8,951,898	$208,771	$6,563,691	$522,088	$0	[redacted]		$113,528
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
367P	UG Cond & Dev - PRI	Total			$189,031,023	$106,503,777	$1,820,846	$62,350,142	$4,357,449	$12,593,108	[redacted]		$1,405,700
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$149,850,967	$86,998,554	$1,365,956	$48,048,566	$3,219,875	$9,059,683	[redacted]		$1,158,334
		Energy	AE-PRI-NRG	NRG-PRI	$39,180,055	$19,505,224	$454,890	$14,301,576	$1,137,575	$3,533,425	[redacted]		$247,366
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
367S	UG Cond & Dev - SEC	Total			$431,636,333	$260,590,463	$4,452,754	$152,498,626	$10,654,859	$0	[redacted]		$3,439,631
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-SEC-DMD	DMD-SEC	$345,002,572	$213,185,957	$3,347,213	$117,740,802	$7,890,155	$0	[redacted]		$2,838,445
		Energy	AE-SEC-NRG	NRG-SEC	$86,633,761	$47,404,507	$1,105,541	$34,757,825	$2,764,704	$0	[redacted]		$601,186
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
368	Line Transformers	Total			$853,891,746	$527,641,658	$8,284,453	$291,412,027	$19,528,372	$0	[redacted]		$7,025,237
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DMD	DMD-SEC	$853,891,746	$527,641,658	$8,284,453	$291,412,027	$19,528,372	$0	[redacted]		$7,025,237
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
369	Services	Total			$469,594,395	$356,073,297	$5,340,261	$107,772,597	$408,240	$0	[redacted]		$0
		Customer	SRVC-CUST	SRVC-CUST	$444,040,534	$355,908,356	$5,339,140	$82,430,952	$362,086	$0	[redacted]		$0
		Demand	SRVC-DMD	SRVC-DMD	$25,553,860	$164,940	$1,121	$25,341,645	$46,154	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
370	Meters	Total			$180,264,239	$105,691,531	$5,617,617	$49,248,340	$1,928,898	$7,817,222	[redacted]		$0
		Customer	MTR-CUST	CUST-MTR	$146,516,339	$101,425,716	$3,774,843	$22,901,299	$636,628	$7,817,222	[redacted]		$0
		Demand	MTR-DMD	DMD-MTR	$33,747,900	$4,265,815	$1,842,773	$26,347,041	$1,292,271	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
371	Install on Cust Premise	Total			$25,980,444	$0	$0	$0	$0	$0	[redacted]		$25,980,444
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DMD	DMD-LTG	$25,980,444	$0	$0	$0	$0	$0	[redacted]		$25,980,444
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
373	St Lt & Signal Sys	Total			$238,449,297	$0	$0	$0	$0	$0	[redacted]		$238,449,297
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	DMD	DMD-LTG	$238,449,297	$0	$0	$0	$0	$0	[redacted]		$238,449,297
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
374	Asset Retirement Costs	Total			$45,657	$25,724	$440	$15,059	$1,052	$3,042	[redacted]		$340
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-PRI-DMD	DMD-PRI	$36,194	$21,013	$330	$11,605	$778	$2,188	[redacted]		$280
		Energy	AE-PRI-NRG	NRG-PRI	$9,463	$4,711	$110	$3,454	$275	$853	[redacted]		$60
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
TOTDISTPLT	Total Distribution PIS	Total			$5,063,247,618	$2,922,548,789	$52,281,619	$1,579,890,550	$100,927,186	$100,668,208	[redacted]		$296,970,635
		Customer			$590,556,873	$457,334,072	$9,113,983	$105,332,251	$998,714	$7,817,222	[redacted]		$0
		Demand			$3,802,197,548	$2,112,587,836	$34,943,872	$1,216,006,018	$79,362,732	$66,798,481	[redacted]		$292,498,607
		Energy			$670,493,197	$352,626,880	$8,223,763	$258,552,281	$20,565,740	$26,052,505	[redacted]		$4,472,028

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
389	Land & Land Rights	Total			$1,494,290	$778,283	$13,312	$455,781	$31,860	$92,090	[redacted]		$10,272
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$1,175,998	$634,900	$9,968	$350,650	$23,498	$66,116	[redacted]		$8,453
		Energy	AE-ALL-NRG	NRG-ALL	$318,292	$143,383	$3,344	$105,131	$8,362	$25,974	[redacted]		$1,818
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
390	Struct & Impmnts	Total			$92,717,272	$48,290,667	$826,004	$28,280,156	$1,976,864	$5,713,985	[redacted]		$637,336
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$72,968,008	$39,394,063	$618,523	$21,757,008	$1,458,001	$4,102,341	[redacted]		$524,509
		Energy	AE-ALL-NRG	NRG-ALL	$19,749,264	$8,896,605	$207,482	$6,523,148	$518,864	$1,611,645	[redacted]		$112,827
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
391	Office Furn & Equip	Total			$29,278,765	$15,249,490	$260,840	$8,930,462	$624,265	$1,804,393	[redacted]		$201,261
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$23,042,235	$12,440,072	$195,320	$6,870,546	$460,415	$1,295,460	[redacted]		$165,632
		Energy	AE-ALL-NRG	NRG-ALL	$6,236,530	$2,809,418	$65,520	$2,059,915	$163,850	$508,934	[redacted]		$35,629
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
392	Transportation Equip	Total			$8,780,078	$4,572,997	$78,220	$2,678,055	$187,204	$541,099	[redacted]		$60,354
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$6,909,875	$3,730,512	$58,572	$2,060,330	$138,069	$388,481	[redacted]		$49,670
		Energy	AE-ALL-NRG	NRG-ALL	$1,870,202	$842,485	$19,648	$617,725	$49,135	$152,618	[redacted]		$10,684
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
393	Stores Equip	Total			$1,490,362	$776,237	$13,277	$454,583	$31,777	$91,848	[redacted]		$10,245
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$1,172,907	$633,230	$9,942	$349,728	$23,436	$65,942	[redacted]		$8,431
		Energy	AE-ALL-NRG	NRG-ALL	$317,455	$143,006	$3,335	$104,855	$8,340	$25,906	[redacted]		$1,814
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
394	Tools, Shop & Garage Equip	Total			$23,055,243	$12,008,044	$205,396	$7,032,194	$491,571	$1,420,850	[redacted]		$158,481
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$18,144,355	$9,795,798	$153,803	$5,410,136	$362,549	$1,020,095	[redacted]		$130,425
		Energy	AE-ALL-NRG	NRG-ALL	$4,910,887	$2,212,246	$51,593	$1,622,058	$129,022	$400,754	[redacted]		$28,056
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
395	Laboratory Equip	Total			$448,981	$233,846	$4,000	$136,946	$9,573	$27,670	[redacted]		$3,086
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	$353,346	$190,765	$2,995	$105,358	$7,060	$19,865	[redacted]		$2,540
		Energy	AE-ALL-NRG	NRG-ALL	$95,635	$43,082	$1,005	$31,588	$2,513	$7,804	[redacted]		$546

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
396	Power Operated Equip	Total			$3,851,265	$2,005,884	$34,310	$1,174,693	$82,114	$237,346	[redacted]	[redacted]	$26,473
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$3,030,925	$1,636,340	$25,692	$903,737	$60,562	$170,402	[redacted]	[redacted]	$21,787
		Energy	AE-ALL-NRG	NRG-ALL	$820,340	$369,545	$8,618	$270,957	$21,552	$66,944	[redacted]	[redacted]	$4,687
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
397	Communication Equip	Total			$36,284,526	$18,898,356	$323,253	$11,067,324	$773,638	$2,236,145	[redacted]	[redacted]	$249,419
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$28,555,732	$15,416,706	$242,056	$8,514,516	$570,583	$1,605,434	[redacted]	[redacted]	$205,264
		Energy	AE-ALL-NRG	NRG-ALL	$7,728,794	$3,481,650	$81,197	$2,552,808	$203,055	$630,711	[redacted]	[redacted]	$44,154
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
398	MISC Equip	Total			$1,384,722	$721,216	$12,336	$422,361	$29,524	$85,338	[redacted]	[redacted]	$9,519
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$1,089,769	$588,346	$9,238	$324,939	$21,775	$61,268	[redacted]	[redacted]	$7,833
		Energy	AE-ALL-NRG	NRG-ALL	$294,953	$132,870	$3,099	$97,423	$7,749	$24,070	[redacted]	[redacted]	$1,685
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
399	Other Tangible Property	Total			$1,458,070	$759,418	$12,990	$444,733	$31,088	$89,858	[redacted]	[redacted]	$10,023
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$1,147,493	$619,510	$9,727	$342,150	$22,928	$64,513	[redacted]	[redacted]	$8,248
		Energy	AE-ALL-NRG	NRG-ALL	$310,576	$139,908	$3,263	$102,583	$8,160	$25,345	[redacted]	[redacted]	$1,774
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
SRVCO-PIS	Service Company PIS	Total			$114,476,272	$59,623,579	$1,019,852	$34,916,977	$2,440,797	$7,054,950	[redacted]	[redacted]	$786,906
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$90,092,227	$48,639,108	$763,678	$26,862,968	$1,800,166	$5,065,083	[redacted]	[redacted]	$647,601
		Energy	AE-ALL-NRG	NRG-ALL	$24,384,045	$10,984,471	$256,174	$8,054,009	$640,631	$1,989,867	[redacted]	[redacted]	$139,305
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTGENPLT	Total General PIS	Total			$314,719,845	$163,918,017	$2,803,791	$95,994,265	$6,710,275	$19,395,572	[redacted]	[redacted]	$2,163,375
		Customer			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand			$247,682,871	$133,719,349	$2,099,515	$73,852,066	$4,949,043	$13,925,000	[redacted]	[redacted]	$1,780,394
		Energy			$67,036,974	$30,198,668	$704,276	$22,142,199	$1,761,233	$5,470,572	[redacted]	[redacted]	$382,981

REDACTED

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
108-303	Misc Intangible Plant - Accum Res	Total			($86,519,616)	($45,062,693)	($770,790)	($26,389,778)	($1,844,721)	($5,332,036)	[redacted]	[redacted]	($594,733)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($68,090,485)	($36,760,779)	($577,178)	($20,302,667)	($1,360,541)	($3,828,121)	[redacted]	[redacted]	($489,448)
		Energy	AE-ALL-NRG	NRG-ALL	($18,429,131)	($8,301,914)	($193,613)	($6,087,111)	($484,180)	($1,503,915)	[redacted]	[redacted]	($105,285)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-360P	Land & Land Rights - PRI - Accum Res	Total			($7,584,141)	($4,273,054)	($73,054)	($2,501,559)	($174,826)	($505,250)	[redacted]	[redacted]	($56,398)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	($6,012,192)	($3,490,482)	($54,804)	($1,927,763)	($129,185)	($363,485)	[redacted]	[redacted]	($46,474)
		Energy	AE-PRI-NRG	NRG-PRI	($1,571,949)	($782,572)	($18,251)	($573,796)	($45,641)	($141,765)	[redacted]	[redacted]	($9,925)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-360S	Land & Land Rights - SEC - Accum Res	Total			($10,868,757)	($6,561,761)	($112,122)	($3,839,970)	($268,293)	$0	[redacted]	[redacted]	($86,611)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	($8,687,288)	($5,368,099)	($84,284)	($2,964,755)	($198,677)	$0	[redacted]	[redacted]	($71,473)
		Energy	AE-SEC-NRG	NRG-SEC	($2,181,469)	($1,193,662)	($27,838)	($875,214)	($69,616)	$0	[redacted]	[redacted]	($15,138)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-361P	Struct & Impmnts -PRI - Accum Res	Total			($9,029,418)	($5,087,351)	($86,976)	($2,978,270)	($208,142)	($601,533)	[redacted]	[redacted]	($67,146)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	($7,157,910)	($4,155,647)	($65,247)	($2,295,129)	($153,803)	($432,753)	[redacted]	[redacted]	($55,330)
		Energy	AE-PRI-NRG	NRG-PRI	($1,871,508)	($931,703)	($21,729)	($683,141)	($54,338)	($168,781)	[redacted]	[redacted]	($11,816)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-361S	Struct & Impmnts -SEC - Accum Res	Total			($5,235,065)	($3,160,550)	($54,005)	($1,849,567)	($129,227)	$0	[redacted]	[redacted]	($41,717)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	($4,184,335)	($2,585,608)	($40,596)	($1,428,009)	($95,695)	$0	[redacted]	[redacted]	($34,426)
		Energy	AE-SEC-NRG	NRG-SEC	($1,050,730)	($574,942)	($13,408)	($421,557)	($33,531)	$0	[redacted]	[redacted]	($7,291)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-362P	Station Equip - PRI - Accum Res	Total			($194,116,809)	($109,369,209)	($1,869,835)	($64,027,641)	($4,474,684)	($12,931,919)	[redacted]	[redacted]	($1,443,520)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	($153,882,634)	($89,339,207)	($1,402,707)	($49,341,289)	($3,306,504)	($9,303,429)	[redacted]	[redacted]	($1,189,499)
		Energy	AE-PRI-NRG	NRG-PRI	($40,234,175)	($20,030,002)	($467,128)	($14,686,353)	($1,168,180)	($3,628,490)	[redacted]	[redacted]	($254,021)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-362S	Station Equip - SEC - Accum Res	Total			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	AE-SEC-NRG	NRG-SEC	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-364P	Poles, Towers & Fixt - PRI - Accum Res	Total			($76,886,747)	($43,319,498)	($740,613)	($25,360,385)	($1,772,355)	($5,122,139)	[redacted]	[redacted]	($571,757)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	($60,950,596)	($35,385,915)	($555,591)	($19,543,342)	($1,309,656)	($3,684,948)	[redacted]	[redacted]	($471,143)
		Energy	AE-PRI-NRG	NRG-PRI	($15,936,151)	($7,933,583)	($185,022)	($5,817,043)	($462,699)	($1,437,190)	[redacted]	[redacted]	($100,614)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-364S	Poles, Towers & Fixt - SEC - Accum Res	Total			($175,564,376)	($105,992,936)	($1,811,119)	($62,027,508)	($4,333,772)	$0	[redacted]	[redacted]	($1,399,040)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-SEC-DMD	DMD-SEC	($140,326,837)	($86,711,559)	($1,361,450)	($47,890,061)	($3,209,253)	$0	[redacted]	[redacted]	($1,154,513)
		Energy	AE-SEC-NRG	NRG-SEC	($35,237,539)	($19,281,376)	($449,669)	($14,137,447)	($1,124,519)	$0	[redacted]	[redacted]	($244,527)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-365P	OH Cond & Dev - PRI - Accum Res	Total			($55,857,566)	($31,471,246)	($538,049)	($18,424,104)	($1,287,601)	($3,721,190)	[redacted]	[redacted]	($415,376)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	($44,280,088)	($25,707,566)	($403,632)	($14,198,071)	($951,454)	($2,677,084)	[redacted]	[redacted]	($342,281)
		Energy	AE-PRI-NRG	NRG-PRI	($11,577,478)	($5,763,680)	($134,417)	($4,226,032)	($336,147)	($1,044,107)	[redacted]	[redacted]	($73,095)

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
108-365S	OH Cond & Dev - SEC - Accum Res	Total			($127,546,023)	($77,002,964)	($1,315,763)	($45,062,456)	($3,148,449)	$0	[redacted]		($1,016,391)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	($101,946,251)	($62,995,209)	($989,082)	($34,791,721)	($2,331,495)	$0			($838,744)
		Energy	AE-SEC-NRG	NRG-SEC	($25,599,772)	($14,007,756)	($326,681)	($10,270,735)	($816,954)	$0			($177,647)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-366P	UG Conduit - PRI - Accum Res	Total			($18,127,237)	($10,213,240)	($174,611)	($5,979,102)	($417,860)	($1,207,623)			($134,800)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	($14,370,044)	($8,342,776)	($130,989)	($4,607,644)	($308,772)	($868,783)			($111,079)
		Energy	AE-PRI-NRG	NRG-PRI	($3,757,194)	($1,870,465)	($43,622)	($1,371,458)	($109,088)	($338,840)			($23,721)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-366S	UG Conduit - SEC - Accum Res	Total			($41,392,011)	($24,989,471)	($426,999)	($14,623,942)	($1,021,754)	$0			($329,845)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	($33,084,218)	($20,443,588)	($320,983)	($11,290,821)	($756,631)	$0			($272,194)
		Energy	AE-SEC-NRG	NRG-SEC	($8,307,794)	($4,545,882)	($106,016)	($3,333,121)	($265,123)	$0			($57,651)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-367P	UG Cond & Dev - PRI - Accum Res	Total			($67,907,701)	($38,260,528)	($654,123)	($22,398,730)	($1,565,375)	($4,523,961)			($504,985)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-PRI-DMD	DMD-PRI	($53,832,617)	($31,253,451)	($490,708)	($17,261,017)	($1,156,711)	($3,254,610)			($416,121)
		Energy	AE-PRI-NRG	NRG-PRI	($14,075,084)	($7,007,077)	($163,415)	($5,137,713)	($408,663)	($1,269,351)			($88,864)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-367S	UG Cond & Dev - SEC - Accum Res	Total			($155,061,485)	($93,614,789)	($1,599,612)	($54,783,765)	($3,827,663)	$0			($1,235,657)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	AE-SEC-DMD	DMD-SEC	($123,939,082)	($76,585,145)	($1,202,456)	($42,297,328)	($2,834,468)	$0			($1,019,686)
		Energy	AE-SEC-NRG	NRG-SEC	($31,122,403)	($17,029,644)	($397,156)	($12,486,437)	($993,195)	$0			($215,971)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-368	Line Transformers - Accum Res	Total			($289,146,526)	($178,671,070)	($2,805,298)	($98,678,522)	($6,612,736)	$0			($2,378,900)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	DMD-SEC	($289,146,526)	($178,671,070)	($2,805,298)	($98,678,522)	($6,612,736)	$0			($2,378,900)
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-369	Services - Accum Res	Total			($189,580,347)	($163,213,810)	($2,519,955)	($23,494,437)	($267,270)	$0			($84,876)
		Customer	SRVC-CUST	CUST-SVCS	($179,263,977)	($156,839,059)	($2,419,866)	($19,973,716)	($31,336)	$0			$0
		Demand	SRVC-DMD	DMD-SEC	($10,316,370)	($6,374,750)	($100,089)	($3,520,721)	($235,934)	$0			($84,876)
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-370	Meters - Accum Res	Total			($35,341,484)	($20,721,223)	($1,101,355)	($9,655,323)	($378,168)	($1,532,596)			$0
		Customer	MTR-CUST	CUST-MTR	($28,725,081)	($19,884,894)	($740,072)	($4,489,886)	($124,813)	($1,532,596)			$0
		Demand	MTR-DMD	DMD-MTR	($6,616,403)	($836,329)	($361,283)	($5,165,437)	($253,355)	$0			$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
108-371	Install on Cust Premise - Accum Res	Total			($8,345,814)	$0	$0	$0	$0	$0			($8,345,814)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0			$0
		Demand	DMD	DMD-LTG	($8,345,814)	$0	$0	$0	$0	$0			($8,345,814)
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0			$0

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108-373	St Lt & Signal Sys - Accum Res	Total			($86,922,368)	$0	$0	$0	$0	$0	[redacted]	[redacted]	($86,922,368)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DMD	DMD-LTG	($86,922,368)	$0	$0	$0	$0	$0	[redacted]	[redacted]	($86,922,368)
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-374	Asset Ret Costs - Accum Res	Total			($28,356)	($15,977)	($273)	($9,353)	($654)	($1,889)	[redacted]	[redacted]	($211)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD	DMD-PRI	($22,479)	($13,051)	($205)	($7,208)	($483)	($1,359)	[redacted]	[redacted]	($174)
		Energy	AE-PRI-NRG	NRG-PRI	($5,877)	($2,926)	($68)	($2,145)	($171)	($530)	[redacted]	[redacted]	($37)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-389	Land & Land Rights - Accum Res	Total			($5,722)	($2,980)	($51)	($1,745)	($122)	($353)	[redacted]	[redacted]	($39)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($4,503)	($2,431)	($38)	($1,343)	($90)	($253)	[redacted]	[redacted]	($32)
		Energy	AE-ALL-NRG	NRG-All	($1,219)	($549)	($13)	($403)	($32)	($99)	[redacted]	[redacted]	($7)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-390	Struct & Impmnts - Accum Res	Total			($54,183,893)	($28,221,024)	($482,716)	($16,526,899)	($1,155,278)	($3,339,248)	[redacted]	[redacted]	($372,458)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($42,642,440)	($23,021,856)	($361,464)	($12,714,776)	($852,054)	($2,397,404)	[redacted]	[redacted]	($306,522)
		Energy	AE-ALL-NRG	NRG-All	($11,541,453)	($5,199,168)	($121,252)	($3,812,122)	($303,223)	($941,844)	[redacted]	[redacted]	($65,936)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-391	Office Furn & Equip - Accum Res	Total			($6,118,526)	($3,186,760)	($54,509)	($1,866,242)	($130,456)	($377,073)	[redacted]	[redacted]	($42,059)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($4,815,248)	($2,599,662)	($40,817)	($1,435,772)	($96,215)	($270,718)	[redacted]	[redacted]	($34,613)
		Energy	AE-ALL-NRG	NRG-All	($1,303,278)	($587,098)	($13,692)	($430,471)	($34,240)	($106,354)	[redacted]	[redacted]	($7,446)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-392	Transportation Equip - Accum Res	Total			($3,822,686)	($1,991,000)	($34,056)	($1,165,977)	($81,505)	($235,585)	[redacted]	[redacted]	($26,277)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($3,008,434)	($1,624,197)	($25,501)	($897,030)	($60,113)	($169,137)	[redacted]	[redacted]	($21,625)
		Energy	AE-ALL-NRG	NRG-All	($814,252)	($366,803)	($8,554)	($268,946)	($21,392)	($66,447)	[redacted]	[redacted]	($4,652)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-393	Stores Equip - Accum Res	Total			($1,257,964)	($655,195)	($11,207)	($383,698)	($26,822)	($77,526)	[redacted]	[redacted]	($8,647)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($990,011)	($534,489)	($8,392)	($295,193)	($19,782)	($55,660)	[redacted]	[redacted]	($7,116)
		Energy	AE-ALL-NRG	NRG-All	($267,953)	($120,707)	($2,815)	($88,504)	($7,040)	($21,866)	[redacted]	[redacted]	($1,531)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
108-394	Tools, Shop & Garage Equip - Accum Res	Total			($10,790,043)	($5,619,863)	($96,127)	($3,291,125)	($230,059)	($664,969)	[redacted]	[redacted]	($74,170)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	($8,491,707)	($4,584,514)	($71,981)	($2,531,988)	($169,676)	($477,413)	[redacted]	[redacted]	($61,040)
		Energy	AE-ALL-NRG	NRG-All	($2,298,336)	($1,035,349)	($24,146)	($759,136)	($60,383)	($187,556)	[redacted]	[redacted]	($13,130)

Jersey Central Power & Light
Depreciation Reserve
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JCP&L's Proposed Alternative COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
108-395	Laboratory Equip - Accum Res	Total			($448,981)	($233,846)	($4,000)	($136,946)	($9,573)	($27,670)	[redacted]		($3,086)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($353,346)	($190,765)	($2,995)	($105,358)	($7,060)	($19,865)	[redacted]		($2,540)
		Energy	AE-ALL-NRG	NRG-All	($95,635)	($43,082)	($1,005)	($31,588)	($2,513)	($7,804)	[redacted]		($546)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-396	Power Operated Equip - Accum Res	Total			($2,847,208)	($1,482,934)	($25,365)	($868,441)	($60,707)	($175,468)	[redacted]		($19,572)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($2,240,738)	($1,209,733)	($18,994)	($668,125)	($44,773)	($125,977)	[redacted]		($16,107)
		Energy	AE-ALL-NRG	NRG-All	($606,470)	($273,201)	($6,371)	($200,316)	($15,934)	($49,491)	[redacted]		($3,465)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-397	Communication Equip - Accum Res	Total			($4,859,396)	($2,530,957)	($43,292)	($1,482,189)	($103,609)	($299,475)	[redacted]		($33,403)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($3,824,319)	($2,064,678)	($32,417)	($1,140,304)	($76,415)	($215,007)	[redacted]		($27,490)
		Energy	AE-ALL-NRG	NRG-All	($1,035,077)	($466,279)	($10,874)	($341,884)	($27,194)	($84,468)	[redacted]		($5,913)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-398	MISC Equip - Accum Res	Total			($921,377)	($479,888)	($8,208)	($281,034)	($19,645)	($56,783)	[redacted]		($6,334)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($725,119)	($391,478)	($6,147)	($216,210)	($14,489)	($40,767)	[redacted]		($5,212)
		Energy	AE-ALL-NRG	NRG-All	($196,258)	($88,410)	($2,062)	($64,824)	($5,156)	($16,016)	[redacted]		($1,121)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108-399	Other Tangible Property - Accum Res	Total			($614,344)	($319,974)	($5,473)	($187,384)	($13,099)	($37,861)	[redacted]		($4,223)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($483,486)	($261,025)	($4,098)	($144,162)	($9,661)	($27,182)	[redacted]		($3,475)
		Energy	AE-ALL-NRG	NRG-All	($130,859)	($58,949)	($1,375)	($43,222)	($3,438)	($10,679)	[redacted]		($748)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
SRVCO-PIS	Service Company PIS - Accum Res	Total			($68,833,640)	($35,851,167)	($613,228)	($20,995,291)	($1,467,631)	($4,242,083)	[redacted]		($473,160)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand	AE-ALL-DMD	DMD-ALL	($54,171,714)	($29,246,295)	($459,193)	($16,152,482)	($1,082,425)	($3,045,593)	[redacted]		($389,397)
		Energy	AE-ALL-NRG	NRG-All	($14,661,926)	($6,604,872)	($154,035)	($4,842,809)	($385,206)	($1,196,491)	[redacted]		($83,763)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108 - Intngbl	Intangible PIS - Accum Res	Total			($86,519,616)	($45,062,693)	($770,790)	($26,389,778)	($1,844,721)	($5,332,036)	[redacted]		($594,733)
		Customer			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			($68,090,485)	($36,760,779)	($577,178)	($20,302,667)	($1,360,541)	($3,828,121)	[redacted]		($489,448)
		Energy			($18,429,131)	($8,301,914)	($193,613)	($6,087,111)	($484,180)	($1,503,915)	[redacted]		($105,285)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108 - Gen	General PIS - Accum Res	Total			($154,703,781)	($80,575,589)	($1,378,232)	($47,186,969)	($3,298,505)	($9,534,093)	[redacted]		($1,063,429)
		Customer			$0	$0	$0	$0	$0	$0	[redacted]		$0
		Demand			($121,751,066)	($65,731,123)	($1,032,038)	($36,302,744)	($2,432,753)	($6,844,977)	[redacted]		($875,171)
		Energy			($32,952,715)	($14,844,466)	($346,194)	($10,884,226)	($865,752)	($2,689,116)	[redacted]		($188,258)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
108 - Dist	Distribution PIS - Accum Res	Total			($1,554,542,233)	($915,938,675)	($15,883,763)	($455,694,634)	($29,888,827)	($30,148,101)	[redacted]		($105,035,413)
		Customer			($207,989,058)	($176,723,953)	($3,159,938)	($24,463,602)	($156,149)	($1,532,596)	[redacted]		$0
		Demand			($1,154,024,051)	($638,259,452)	($10,369,404)	($357,208,838)	($23,844,812)	($20,586,451)	[redacted]		($103,755,095)
		Energy			($192,529,124)	($100,955,270)	($2,354,421)	($74,022,194)	($5,887,866)	($8,029,054)	[redacted]		($1,280,319)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
TOTDPRRES	Total PIS - Accum Res	Total			($1,795,765,630)	($1,041,576,958)	($18,032,786)	($529,271,382)	($35,032,054)	($45,014,230)	[redacted]		($106,693,576)
		Customer			($207,989,058)	($176,723,953)	($3,159,938)	($24,463,602)	($156,149)	($1,532,596)	[redacted]		$0
		Demand			($1,343,865,602)	($740,751,354)	($11,978,620)	($413,814,249)	($27,638,106)	($31,259,549)	[redacted]		($105,119,714)
		Energy			($243,910,970)	($124,101,650)	($2,894,228)	($90,993,530)	($7,237,799)	($12,222,085)	[redacted]		($1,573,862)

REDACTED

Jersey Central Power & Light
Rate Base Additions & Deductions
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
RB-CUSTDEP	Acct 235 - Cust Deposits	Total			($47,386,955)	($41,437,530)	($639,339)	($5,277,139)	($8,279)	($17,777)	[redacted]		$0
		Customer	CUST	CUST-DEP	($47,386,955)	($41,437,530)	($639,339)	($5,277,139)	($8,279)	($17,777)	[redacted]		$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]		$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
RB-CAFC	Acct 252 - Cust Adv for Const	Total			($34,598,405)	($19,970,488)	($357,253)	($10,795,777)	($689,660)	($687,890)	[redacted]		($2,029,273)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($4,035,419)	($3,125,075)	($62,278)	($719,761)	($6,824)	($53,417)	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($25,981,343)	($14,435,828)	($238,780)	($8,309,265)	($542,305)	($456,450)	[redacted]		($1,998,714)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($4,581,643)	($2,409,585)	($56,195)	($1,766,751)	($140,531)	($178,023)	[redacted]		($30,558)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
RB-ADIT	Accum Deferred Inc Tx	Total			($1,102,329,656)	($636,273,879)	($11,382,335)	($343,961,097)	($21,973,057)	($21,916,675)	[redacted]		($64,654,064)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($128,571,305)	($99,567,106)	($1,984,223)	($22,932,093)	($217,432)	($1,701,903)	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($827,783,950)	($459,935,677)	($7,607,700)	($264,739,076)	($17,278,217)	($14,542,830)	[redacted]		($63,680,450)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($145,974,401)	($76,771,096)	($1,790,412)	($56,289,929)	($4,477,408)	($5,671,942)	[redacted]		($973,614)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
RB-REAQDBT	Unamort G/L on Reaquired Debt	Total			$2,178,358	$1,257,366	$22,493	$679,715	$43,422	$43,310	[redacted]		$127,765
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$254,075	$196,759	$3,921	$45,317	$430	$3,363	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$1,635,817	$908,897	$15,034	$523,162	$34,144	$28,739	[redacted]		$125,842
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$288,466	$151,710	$3,538	$111,237	$8,848	$11,209	[redacted]		$1,924
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
RB-M&S	Materials & Supplies	Total			$22,844,588	$13,186,087	$235,887	$7,128,221	$455,368	$454,199	[redacted]		$1,339,885
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$2,664,501	$2,063,420	$41,121	$475,243	$4,506	$35,270	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$17,154,926	$9,531,669	$157,661	$5,486,431	$358,072	$301,384	[redacted]		$1,319,708
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$3,025,161	$1,590,998	$37,104	$1,166,548	$92,789	$117,545	[redacted]		$20,177
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
RB-CWC	Cash Working Capital	Total			$114,525,841	$65,131,459	$1,741,661	$35,822,432	$2,232,436	$3,863,736	[redacted]		$4,116,993
		Customer	CWC-CUST	CWC-CUST	$23,893,092	$16,553,587	$616,088	$3,737,698	$103,903	$1,275,841	[redacted]		$0
		Demand	CWC-DMD	CWC-DMD	$73,629,476	$39,371,728	$914,109	$25,833,241	$1,646,368	$1,854,481	[redacted]		$4,009,550
		Energy	CWC-NRG	CWC-NRG	$17,003,273	$9,206,144	$211,463	$6,251,493	$482,166	$733,414	[redacted]		$107,443
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
RB-EXCOR	Unamort Excess Cost of Removal	Total			($87,758,072)	($50,654,692)	($906,164)	($27,383,245)	($1,749,307)	($1,744,818)	[redacted]		($5,147,204)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($10,235,749)	($7,926,683)	($157,967)	($1,825,657)	($17,310)	($135,491)	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($65,901,088)	($36,616,150)	($605,660)	($21,076,264)	($1,375,544)	($1,157,776)	[redacted]		($5,069,694)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($11,621,235)	($6,111,859)	($142,537)	($4,481,323)	($356,453)	($451,552)	[redacted]		($77,511)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]		LTG
RB-REF	Customer Refunds	Total			($4,033,419)	($2,328,123)	($41,648)	($1,258,552)	($80,399)	($80,193)	[redacted]		($236,569)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($470,442)	($364,316)	($7,260)	($83,908)	($796)	($6,227)	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($3,028,858)	($1,682,902)	($27,837)	($968,679)	($63,221)	($53,212)	[redacted]		($233,006)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($534,120)	($280,905)	($6,551)	($205,965)	($16,383)	($20,754)	[redacted]		($3,562)

Jersey Central Power & Light
Rate Base Additions & Deductions
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
RB-OPRES	Net Operating Reserves	Total			($10,699,965)	($6,056,602)	($137,871)	($3,419,088)	($224,094)	($505,942)	[redacted]		($258,165)
		Customer	PAY-CUST	PAY-CUST	($1,315,952)	($904,928)	($33,679)	($204,327)	($5,680)	($69,746)	[redacted]		$0
		Demand	PAY-DMD	PAY-DMD	($7,543,419)	($4,194,803)	($82,053)	($2,540,446)	($165,604)	($313,973)	[redacted]		($246,540)
		Energy	PAY-NRG	PAY-NRG	($1,840,594)	($956,871)	($22,138)	($674,315)	($52,811)	($122,223)	[redacted]		($11,626)

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-NOL	NOL- Net Operating Losses	Total			$22,826,438	$13,175,610	$235,699	$7,122,558	$455,006	$453,838	[redacted]		$1,338,821
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$2,662,384	$2,061,781	$41,088	$474,865	$4,502	$35,242	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$17,141,296	$9,524,096	$157,536	$5,482,071	$357,788	$301,145	[redacted]		$1,318,660
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$3,022,758	$1,589,734	$37,075	$1,165,621	$92,716	$117,451	[redacted]		$20,161

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-CTA	CTA	Total			($20,787,390)	($11,905,321)	($212,299)	($6,474,695)	($416,659)	($482,417)	[redacted]		($1,133,496)
		Customer	RB-PLT-CUST	RB-PLT-CUST	($2,231,441)	($1,728,054)	($34,438)	($398,002)	($3,774)	($29,538)	[redacted]		$0
		Demand	RB-PLT-DMD	RB-PLT-DMD	($15,669,788)	($8,685,980)	($143,082)	($4,983,255)	($325,912)	($325,659)	[redacted]		($1,114,583)
		Energy	RB-PLT-NRG	RB-PLT-NRG	($2,886,161)	($1,491,287)	($34,779)	($1,093,438)	($86,974)	($127,221)	[redacted]		($18,913)

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-PRAMT	Property-Related Unprotected Amort	Total			$32,052,681	$18,501,075	$330,967	$10,001,432	$638,915	$637,276	[redacted]		$1,879,960
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$3,738,496	$2,895,135	$57,696	$666,801	$6,322	$49,487	[redacted]		$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$24,069,655	$13,373,650	$221,211	$7,697,876	$502,403	$422,865	[redacted]		$1,851,650
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$4,244,530	$2,232,290	$52,060	$1,636,755	$130,191	$164,924	[redacted]		$28,310

Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
RB-ADD/DED	Rate Base Adds and Deducts	Total			($1,113,165,957)	($657,375,037)	($11,110,202)	($337,815,235)	($21,316,309)	($19,983,353)	[redacted]		($64,655,347)
		Customer			($161,034,716)	($131,283,008)	($2,159,270)	($26,040,963)	($140,431)	($614,896)	[redacted]		$0
		Demand			($812,277,275)	($452,841,301)	($7,239,560)	($257,594,204)	($16,852,028)	($13,941,287)	[redacted]		($63,717,578)
		Energy			($139,853,966)	($73,250,728)	($1,711,372)	($54,180,067)	($4,323,850)	($5,427,171)	[redacted]		($937,769)

Jersey Central Power & Light
Rate Base Summary
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Account	Description	Category	Total	RS	RT	GS	GST	GP	GT	GT	LTG
RB-PIS	Rate Base Plant In Service	Total	$5,504,036,320	$3,152,128,242	$56,208,538	$1,714,337,704	$110,325,429	$127,833,159	[redacted]	[redacted]	$300,000,603
		Customer	$590,556,873	$457,334,072	$9,113,983	$105,332,251	$998,714	$7,817,222	[redacted]	[redacted]	$0
		Demand	$4,149,095,949	$2,299,871,794	$37,884,400	$1,319,441,365	$86,294,237	$86,301,487	[redacted]	[redacted]	$294,992,183
		Energy	$764,383,497	$394,922,375	$9,210,154	$289,564,088	$23,032,479	$33,714,451	[redacted]	[redacted]	$5,008,421
Account	Description	Category	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-ADD/DED	Rate Base Adds & Deducts	Total	($1,113,165,957)	($657,375,037)	($11,110,202)	($337,815,235)	($21,316,309)	($19,983,353)	[redacted]	[redacted]	($64,655,347)
		Customer	($161,034,716)	($131,283,008)	($2,159,270)	($26,040,963)	($140,431)	($614,896)	[redacted]	[redacted]	$0
		Demand	($812,277,275)	($452,841,301)	($7,239,560)	($257,594,204)	($16,852,028)	($13,941,287)	[redacted]	[redacted]	($63,717,578)
		Energy	($139,853,966)	($73,250,728)	($1,711,372)	($54,180,067)	($4,323,850)	($5,427,171)	[redacted]	[redacted]	($937,769)
Account	Description	Category	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTRBADJ	Total Rate Base Adjustments	Total	$3,819,060	$2,831,812	($104,346)	$769,737	$19,380	($1,463,397)	[redacted]	[redacted]	$2,163,416
		Customer	$88,693	$668,035	($68,827)	$175,354	($17,987)	($273,542)	[redacted]	[redacted]	$0
		Demand	$5,448,898	$3,009,122	($16,735)	$1,070,983	$70,942	($856,877)	[redacted]	[redacted]	$2,171,463
		Energy	($1,718,532)	($845,344)	($18,785)	($476,600)	($33,575)	($332,978)	[redacted]	[redacted]	($8,047)
Account	Description	Category	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTDPRRES	Total PIS - Accum Res	Total	($1,795,765,630)	($1,041,576,958)	($18,032,786)	($529,271,382)	($35,032,054)	($45,014,230)	[redacted]	[redacted]	($106,693,576)
		Customer	($207,989,058)	($176,723,953)	($3,159,938)	($24,463,602)	($156,149)	($1,532,596)	[redacted]	[redacted]	$0
		Demand	($1,343,865,602)	($740,751,354)	($11,978,620)	($413,814,249)	($27,638,106)	($31,259,549)	[redacted]	[redacted]	($105,119,714)
		Energy	($243,910,970)	($124,101,650)	($2,894,228)	($90,993,530)	($7,237,799)	($12,222,085)	[redacted]	[redacted]	($1,573,862)
Sub-Total	Description	Category	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-TOT	Total Distribution Rate Base	Total	$2,598,923,793	$1,456,008,059	$26,961,204	$848,020,824	$53,996,447	$61,372,180	[redacted]	[redacted]	$130,815,097
		Customer	$221,621,793	$149,995,145	$3,725,948	$55,003,041	$684,147	$5,396,188	[redacted]	[redacted]	$0
		Demand	$1,998,401,970	$1,109,288,261	$18,649,486	$649,103,894	$41,875,045	$40,243,774	[redacted]	[redacted]	$128,326,354
		Energy	$378,900,030	$196,724,653	$4,585,770	$143,913,890	$11,437,255	$15,732,218	[redacted]	[redacted]	$2,488,743

REDACTED

Jersey Central Power & Light
Interest Expense
Test Year: July 2019 - June 2020
JCP&L's Proposed Alternative COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
INTEXP	Interest Expense	Total			$62,352,756	$34,932,196	$646,847	$20,345,512	$1,295,470	$1,472,427	[redacted]	[redacted]	$3,138,484
		Customer	RB-CUST	RB-CUST	$5,317,097	$3,598,648	$89,392	$1,319,620	$16,414	$129,464	[redacted]	[redacted]	$0
		Demand	RB-DMD	RB-DMD	$47,945,180	$26,613,778	$447,434	$15,573,145	$1,004,656	$965,519	[redacted]	[redacted]	$3,078,775
		Energy	RB-NRG	RB-NRG	$9,090,479	$4,719,771	$110,021	$3,452,748	$274,400	$377,444	[redacted]	[redacted]	$59,709
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTINTEXP	Total Interest Expense	Total			$62,352,756	$34,932,196	$646,847	$20,345,512	$1,295,470	$1,472,427	[redacted]	[redacted]	$3,138,484
		Customer			$5,317,097	$3,598,648	$89,392	$1,319,620	$16,414	$129,464	[redacted]	[redacted]	$0
		Demand			$47,945,180	$26,613,778	$447,434	$15,573,145	$1,004,656	$965,519	[redacted]	[redacted]	$3,078,775
		Energy			$9,090,479	$4,719,771	$110,021	$3,452,748	$274,400	$377,444	[redacted]	[redacted]	$59,709

Jersey Central Power & Light
Income Tax Expenses
Test Year July 2019 - June 2020
JCP&L's Proposed Alternative COSS

Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
PRETXNI	Pre-Tax Net Income	Total			($640,724)	($18,671,650)	$226,429	$9,401,051	($188,814)	$3,561,702	[redacted]		($2,003,278)
		Customer	RB-CUST	RB-CUST	($9,704,673)	($6,118,758)	($278,152)	$1,092,447	($85,498)	($1,858,752)			$0
		Demand	RB-DMD	RB-DMD	($250,036,183)	($219,519,932)	($3,916,789)	($33,771,871)	$194,781	$5,584,320			($6,430,864)
		Energy	RB-NRG	RB-NRG	$259,100,132	$206,967,040	$4,421,369	$42,080,475	($298,097)	($163,865)			$4,427,586
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
STTXEXP	State Tax Expense	Total			($57,665)	($1,680,449)	$20,379	$846,095	($16,993)	$320,553			($180,295)
		Customer	RB-CUST	RB-CUST	($873,421)	($550,688)	($25,034)	$98,320	($7,695)	($167,288)			$0
		Demand	RB-DMD	RB-DMD	($22,503,256)	($19,756,794)	($352,511)	($3,039,468)	$17,530	$502,589			($578,778)
		Energy	RB-NRG	RB-NRG	$23,319,012	$18,627,034	$397,923	$3,787,243	($26,829)	($14,748)			$398,483
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
FEDTXEXP	Federal Tax Expense	Total			($122,442)	($3,568,152)	$43,270	$1,796,541	($36,082)	$680,641			($382,826)
		Customer	RB-CUST	RB-CUST	($1,854,563)	($1,169,295)	($53,155)	$208,767	($16,339)	($355,208)			$0
		Demand	RB-DMD	RB-DMD	($47,781,914)	($41,950,259)	($748,498)	($6,453,805)	$37,223	$1,067,164			($1,228,938)
		Energy	RB-NRG	RB-NRG	$49,514,035	$39,551,401	$844,924	$8,041,579	($56,966)	($31,315)			$846,112
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
FEDITC	Amortization of Fed Income Tax Credit	Total			($97,625)	($54,693)	($1,013)	($31,855)	($2,028)	($2,305)			($4,914)
		Customer	RB-CUST	RB-CUST	($8,325)	($5,634)	($140)	($2,066)	($26)	($203)			$0
		Demand	RB-DMD	RB-DMD	($75,067)	($41,669)	($701)	($24,383)	($1,573)	($1,512)			($4,820)
		Energy	RB-NRG	RB-NRG	($14,233)	($7,390)	($172)	($5,406)	($430)	($591)			($93)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
FEDTAXRFM	Federal Tax Reform Amortization	Total			(5,291,287)	($2,964,364)	($54,892)	($1,726,531)	($109,934)	($124,951)			($266,333)
		Customer	RB-CUST	RB-CUST	($451,212)	($305,383)	($7,586)	($111,984)	($1,393)	($10,986)			$0
		Demand	RB-DMD	RB-DMD	($4,068,652)	($2,258,459)	($37,969)	($1,321,545)	($85,256)	($81,934)			($261,266)
		Energy	RB-NRG	RB-NRG	($771,423)	($400,522)	($9,336)	($293,002)	($23,286)	($32,030)			($5,067)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP			LTG
TOTITEXP	Total Income Tax Expense	Total			($5,569,019)	($8,267,658)	$7,745	$884,250	($165,038)	$873,938			($834,369)
		Customer			($3,187,520)	($2,031,000)	($85,914)	$193,037	($25,452)	($533,684)			$0
		Demand			($74,428,891)	($64,007,181)	($1,139,679)	($10,839,201)	($32,076)	$1,486,306			($2,073,803)
		Energy			$72,047,392	$57,770,523	$1,233,338	$11,530,414	($107,510)	($78,684)			$1,239,434

Jersey Central Power & Light
Income Statement Summary
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		Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
Operating Revenues										
Distribution Revenues		$542,868,768	$283,576,706	$6,369,034	$179,570,595	$11,123,447	$25,384,277	[redacted]	[redacted]	$17,833,311
	Customer	$41,918,982	$30,980,844	$886,940	$9,291,578	$94,289	$250,047	[redacted]	[redacted]	$0
	Demand	$150,980,629	$0	$0	$95,229,974	$8,719,365	$19,685,757	[redacted]	[redacted]	$12,839,173
	Energy	$349,969,157	$252,595,861	$5,482,095	$75,049,042	$2,309,794	$5,448,473	[redacted]	[redacted]	$4,994,139
Other Operating Revenues		$15,543,099	$9,515,959	$175,214	$4,613,612	$249,202	$379,472	[redacted]	[redacted]	$735,918
	Customer	$756,013	$585,466	$11,667	$134,843	$1,279	$10,007	[redacted]	[redacted]	$0
	Demand	$13,928,740	$8,479,071	$153,018	$4,147,778	$221,596	$336,113	[redacted]	[redacted]	$730,193
	Energy	$858,345	$451,422	$10,528	$330,991	$26,328	$33,352	[redacted]	[redacted]	$5,725
Adjustments to Revenues		($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)	[redacted]	[redacted]	($9,867)
	Customer	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
	Demand	($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)	[redacted]	[redacted]	($9,867)
	Energy	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Total Operating Revenues		$558,143,786	$292,968,083	$6,540,908	$184,085,449	$11,366,651	$25,748,984	[redacted]	[redacted]	$18,559,362
	Customer	$42,674,996	$31,566,310	$898,607	$9,426,421	$95,567	$260,054	[redacted]	[redacted]	$0
	Demand	$164,641,287	$8,354,490	$149,679	$99,278,994	$8,934,962	$20,007,105	[redacted]	[redacted]	$13,559,498
	Energy	$350,827,503	$253,047,284	$5,492,623	$75,380,033	$2,336,121	$5,481,825	[redacted]	[redacted]	$4,999,864
Operations & Maintenance Expenses										
Production O&M Expense		$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
	Customer	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
	Demand	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
	Energy	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Distribution O&M Expense		$93,816,859	$52,573,867	$1,029,365	$30,478,511	$2,065,958	$2,566,925	[redacted]	[redacted]	$4,770,968
	Customer	$4,872,763	$3,373,163	$125,542	$761,639	$21,173	$259,981	[redacted]	[redacted]	$0
	Demand	$72,762,186	$40,700,427	$705,585	$23,484,318	$1,549,036	$1,659,653	[redacted]	[redacted]	$4,663,167
	Energy	$16,181,910	$8,500,276	$198,239	$6,232,553	$495,749	$647,292	[redacted]	[redacted]	$107,801
Customer Accounts Expense		$30,283,331	$18,044,768	$918,764	$8,147,051	$313,776	$1,256,058	[redacted]	[redacted]	$4,540
	Customer	$23,317,839	$16,141,739	$600,760	$3,644,705	$101,318	$1,244,098	[redacted]	[redacted]	$0
	Demand	$5,370,924	$678,898	$293,274	$4,193,089	$205,663	$0	[redacted]	[redacted]	$0
	Energy	$1,594,568	$1,224,131	$24,729	$309,257	$6,795	$11,960	[redacted]	[redacted]	$4,540

REDACTED

Jersey Central Power & Light
Income Statement Summary
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		Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
Customer Service Expense		$10,968,363	$6,179,790	$105,653	$3,617,813	$252,837	$730,704	[redacted]	[redacted]	$81,565
	Customer	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
	Demand	$8,694,974	$5,048,016	$79,258	$2,787,977	$186,830	$525,680	[redacted]	[redacted]	$67,211
	Energy	$2,273,389	$1,131,774	$26,395	$829,837	$66,007	$205,024	[redacted]	[redacted]	$14,353
Sales Expense		$56,383	$31,767	$543	$18,598	$1,300	$3,756	[redacted]	[redacted]	$419
	Customer	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
	Demand	$44,697	$25,950	$407	$14,332	$960	$2,702	[redacted]	[redacted]	$346
	Energy	$11,686	$5,818	$136	$4,266	$339	$1,054	[redacted]	[redacted]	$74
A&G Expense		$95,621,463	$53,781,356	$918,892	$31,471,194	$2,198,757	$6,353,267	[redacted]	[redacted]	$709,887
	Customer	$188,111	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
	Demand	$75,802,207	$44,008,274	$690,970	$24,305,398	$1,628,776	$4,582,846	[redacted]	[redacted]	$585,944
	Energy	$19,631,146	$9,773,082	$227,922	$7,165,797	$569,981	$1,770,421	[redacted]	[redacted]	$123,943
Adjustments to Expenses		($3,373,977)	($1,489,797)	($76,120)	($1,164,859)	($69,101)	($308,226)	[redacted]	[redacted]	($260,678)
	Customer	($693,546)	($269,476)	($31,854)	($157,430)	($7,716)	($96,551)	[redacted]	[redacted]	$0
	Demand	($2,026,084)	($799,859)	($35,028)	($823,704)	($50,797)	($153,606)	[redacted]	[redacted]	($254,656)
	Energy	($654,346)	($420,462)	($9,237)	($183,725)	($10,589)	($58,068)	[redacted]	[redacted]	($6,022)
Total O&M Expenses		$227,372,423	$129,121,751	$2,897,097	$72,568,308	$4,763,526	$10,602,485	[redacted]	[redacted]	$5,306,701
	Customer	$27,685,167	$19,245,426	$694,448	$4,248,914	$114,775	$1,407,528	[redacted]	[redacted]	$0
	Demand	$160,648,904	$89,661,706	$1,734,466	$53,961,410	$3,520,469	$6,617,276	[redacted]	[redacted]	$5,062,012
	Energy	$39,038,352	$20,214,619	$468,183	$14,357,985	$1,128,282	$2,577,682	[redacted]	[redacted]	$244,689
Depreciation Expense								[redacted]	[redacted]	
Depreciation Expense		$119,867,916	$67,611,470	$1,345,986	$36,009,862	$2,362,976	$2,596,290	[redacted]	[redacted]	$8,844,795
	Customer	$14,360,051	$11,034,131	$296,552	$1,975,869	$37,432	$446,782	[redacted]	[redacted]	$0
	Demand	$90,463,098	$48,752,979	$866,959	$28,297,034	$1,869,215	$1,545,757	[redacted]	[redacted]	$8,745,566
	Energy	$15,044,766	$7,824,360	$182,475	$5,736,960	$456,329	$603,750	[redacted]	[redacted]	$99,229
Ajustments to Depreciation		$25,777,280	$14,642,159	$282,416	$7,834,318	$509,866	$544,481	[redacted]	[redacted]	$1,784,161
	Customer	$3,063,455	$2,359,400	$58,523	$458,550	$7,154	$79,073	[redacted]	[redacted]	$0
	Demand	$19,424,648	$10,566,116	$183,858	$6,117,096	$402,595	$334,727	[redacted]	[redacted]	$1,762,390
	Energy	$3,289,176	$1,716,642	$40,035	$1,258,672	$100,117	$130,681	[redacted]	[redacted]	$21,771
Total Depreciation Expense		$145,645,195	$82,253,629	$1,628,402	$43,844,180	$2,872,842	$3,140,771	[redacted]	[redacted]	$10,628,956
	Customer	$17,423,507	$13,393,531	$355,075	$2,434,419	$44,586	$525,856	[redacted]	[redacted]	$0
	Demand	$109,887,746	$59,319,095	$1,050,817	$34,414,130	$2,271,810	$1,880,484	[redacted]	[redacted]	$10,507,957
	Energy	$18,333,942	$9,541,002	$222,510	$6,995,632	$556,446	$734,431	[redacted]	[redacted]	$120,999

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		Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
Amortization Expense										
Amortization Expense		$31,325,803	$16,628,799	$287,314	$9,597,524	$660,551	$1,695,150	[redacted]	[redacted]	$509,876
	Customer	$663,775	$514,035	$10,244	$118,391	$1,123	$8,786	[redacted]	[redacted]	$0
	Demand	$24,362,269	$13,220,007	$209,560	$7,356,645	$490,601	$1,204,487	[redacted]	[redacted]	$473,164
	Energy	$6,299,759	$2,894,757	$67,510	$2,122,487	$168,827	$481,877	[redacted]	[redacted]	$36,711
Adjustments to Amortization		$82,185,866	$43,065,205	$740,415	$25,204,451	$1,760,125	$4,927,060	[redacted]	[redacted]	$589,644
	Customer	$149,455	$103,070	$3,790	$23,284	$636	$7,786	[redacted]	[redacted]	$0
	Demand	$64,611,222	$35,050,289	$552,128	$19,383,088	$1,298,390	$3,531,957	[redacted]	[redacted]	$489,362
	Energy	$17,425,189	$7,911,847	$184,496	$5,798,079	$461,099	$1,387,318	[redacted]	[redacted]	$100,282
Total Amortization Expense		$113,511,669	$59,694,004	$1,027,729	$34,801,975	$2,420,676	$6,622,210	[redacted]	[redacted]	$1,099,520
	Customer	$813,230	$617,105	$14,034	$141,676	$1,759	$16,572	[redacted]	[redacted]	$0
	Demand	$88,973,491	$48,270,295	$761,689	$26,739,733	$1,788,992	$4,736,444	[redacted]	[redacted]	$962,527
	Energy	$23,724,948	$10,806,604	$252,006	$7,920,566	$629,925	$1,869,194	[redacted]	[redacted]	$136,993
Taxes Other Than Income										
Taxes Other Than Income		$9,557,328	$5,442,791	$109,958	$3,014,136	$195,723	$333,069	[redacted]	[redacted]	$380,651
	Customer	$1,098,221	$801,169	$22,723	$182,755	$3,349	$37,137	[redacted]	[redacted]	$0
	Demand	$6,978,827	$3,874,240	$69,414	$2,280,504	$148,913	$212,934	[redacted]	[redacted]	$371,139
	Energy	$1,480,280	$767,383	$17,820	$550,877	$43,461	$82,997	[redacted]	[redacted]	$9,512
Adjustments to Taxes Other		$345,139	$195,362	$4,447	$110,286	$7,228	$16,320	[redacted]	[redacted]	$8,327
	Customer	$42,447	$29,189	$1,086	$6,591	$183	$2,250	[redacted]	[redacted]	$0
	Demand	$243,321	$135,308	$2,647	$81,945	$5,342	$10,128	[redacted]	[redacted]	$7,952
	Energy	$59,370	$30,865	$714	$21,751	$1,703	$3,942	[redacted]	[redacted]	$375
Total Taxes Other Than Income		$9,902,467	$5,638,154	$114,405	$3,124,422	$202,951	$349,388	[redacted]	[redacted]	$388,979
	Customer	$1,140,669	$830,358	$23,810	$189,346	$3,533	$39,387	[redacted]	[redacted]	$0
	Demand	$7,222,148	$4,009,547	$72,061	$2,362,449	$154,254	$223,062	[redacted]	[redacted]	$379,092
	Energy	$1,539,650	$798,248	$18,534	$572,627	$45,165	$86,940	[redacted]	[redacted]	$9,887
Income Taxes										
State Income Taxes		($57,665)	($1,680,449)	$20,379	$846,095	($16,993)	$320,553	[redacted]	[redacted]	($180,295)
	Customer	($873,421)	($550,688)	($25,034)	$98,320	($7,695)	($167,288)	[redacted]	[redacted]	$0
	Demand	($22,503,256)	($19,756,794)	($352,511)	($3,039,468)	$17,530	$502,589	[redacted]	[redacted]	($578,778)
	Energy	$23,319,012	$18,627,034	$397,923	$3,787,243	($26,829)	($14,748)	[redacted]	[redacted]	$398,483

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Jersey Central Power & Light
Income Statement Summary
Test Year: July 2019 - June 2020
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		Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
Federal Income Taxes		($122,442)	($3,568,152)	$43,270	$1,796,541	($36,082)	$680,641	[redacted]	[redacted]	($382,826)
	Customer	($1,854,563)	($1,169,295)	($53,155)	$208,767	($16,339)	($355,208)	[redacted]	[redacted]	$0
	Demand	($47,781,914)	($41,950,259)	($748,498)	($6,453,805)	$37,223	$1,067,164	[redacted]	[redacted]	($1,228,938)
	Energy	$49,514,035	$39,551,401	$844,924	$8,041,579	($56,966)	($31,315)	[redacted]	[redacted]	$846,112
Investment Tax Credit		($97,625)	($54,693)	($1,013)	($31,855)	($2,028)	($2,305)	[redacted]	[redacted]	($4,914)
	Customer	($8,325)	($5,634)	($140)	($2,066)	($26)	($203)	[redacted]	[redacted]	$0
	Demand	($75,067)	($41,669)	($701)	($24,383)	($1,573)	($1,512)	[redacted]	[redacted]	($4,820)
	Energy	($14,233)	($7,390)	($172)	($5,406)	($430)	($591)	[redacted]	[redacted]	($93)
Federal Tax Reform		($5,291,287)	($2,964,364)	($54,892)	($1,726,531)	($109,934)	($124,951)	[redacted]	[redacted]	($266,333)
	Customer	($451,212)	($305,383)	($7,586)	($111,984)	($1,393)	($10,986)	[redacted]	[redacted]	$0
	Demand	($4,068,652)	($2,258,459)	($37,969)	($1,321,545)	($85,256)	($81,934)	[redacted]	[redacted]	($261,266)
	Energy	($771,423)	($400,522)	($9,336)	($293,002)	($23,286)	($32,030)	[redacted]	[redacted]	($5,067)
Total Income Taxes		($5,569,019)	($8,267,658)	$7,745	$884,250	($165,038)	$873,938	[redacted]	[redacted]	($834,369)
	Customer	($3,187,520)	($2,031,000)	($85,914)	$193,037	($25,452)	($533,684)	[redacted]	[redacted]	$0
	Demand	($74,428,891)	($64,007,181)	($1,139,679)	($10,839,201)	($32,076)	$1,486,306	[redacted]	[redacted]	($2,073,803)
	Energy	$72,047,392	$57,770,523	$1,233,338	$11,530,414	($107,510)	($78,684)	[redacted]	[redacted]	$1,239,434
Net Operating Income		$67,281,051	$24,528,203	$865,531	$28,862,313	$1,271,694	$4,160,191	[redacted]	[redacted]	$1,969,575
	Customer	($1,200,056)	($489,110)	($102,846)	$2,219,030	($43,632)	($1,195,604)	[redacted]	[redacted]	$0
	Demand	($127,662,112)	($128,898,974)	($2,329,675)	($7,359,526)	$1,231,513	$5,063,533	[redacted]	[redacted]	($1,278,286)
	Energy	$196,143,219	$153,916,287	$3,298,052	$34,002,809	$83,814	$292,262	[redacted]	[redacted]	$3,247,861
Interest Expense		$62,352,756	$34,932,196	$646,847	$20,345,512	$1,295,470	$1,472,427	[redacted]	[redacted]	$3,138,484
	Customer	$5,317,097	$3,598,648	$89,392	$1,319,620	$16,414	$129,464	[redacted]	[redacted]	$0
	Demand	$47,945,180	$26,613,778	$447,434	$15,573,145	$1,004,656	$965,519	[redacted]	[redacted]	$3,078,775
	Energy	$9,090,479	$4,719,771	$110,021	$3,452,748	$274,400	$377,444	[redacted]	[redacted]	$59,709
Net Income		$4,928,295	($10,403,993)	$218,684	$8,516,801	($23,776)	$2,687,764	[redacted]	[redacted]	($1,168,909)
	Customer	($6,517,153)	($4,087,757)	($192,238)	$899,410	($60,046)	($1,325,068)	[redacted]	[redacted]	$0
	Demand	($175,607,292)	($155,512,752)	($2,777,109)	($22,932,670)	$226,857	$4,098,014	[redacted]	[redacted]	($4,357,062)
	Energy	$187,052,740	$149,196,517	$3,188,031	$30,550,062	($190,586)	($85,182)	[redacted]	[redacted]	$3,188,152
Rate Base		$2,598,923,793	$1,456,008,059	$26,961,204	$848,020,824	$53,996,447	$61,372,180	[redacted]	[redacted]	$130,815,097
Rate of Return		2 59%	1.68%	3.21%	3.40%	2.36%	6.78%	[redacted]	[redacted]	1.51%

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Jersey Central Power & Light
Adjustments
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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-1	Revenue Normalization	Total			($319,110)	($166,693)	($3,744)	($105,555)	($6,539)	($14,921)	[redacted]	[redacted]	($10,483)
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DMD	REV-ALL	($319,110)	($166,693)	($3,744)	($105,555)	($6,539)	($14,921)	[redacted]	[redacted]	($10,483)
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-2	Tariff Fee Adjustments	Total			$51,028	$42,111	$404	$6,797	$540	$156	[redacted]	[redacted]	$616
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DMD	ALL451	$51,028	$42,111	$404	$6,797	$540	$156	[redacted]	[redacted]	$616
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-3	Int on Cust Deposits	Total			$1,104,116	$965,494	$14,897	$122,957	$193	$414	[redacted]	[redacted]	$0
		Customer	CUST	CUST-DEP	$1,104,116	$965,494	$14,897	$122,957	$193	$414	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-4	Annualize Payroll Increase	Total			$4,511,619	$2,553,754	$58,133	$1,441,652	$94,489	$213,329	[redacted]	[redacted]	$108,855
		Customer	PAY-CUST	PAY-CUST	$554,869	$381,561	$14,201	$86,154	$2,395	$29,408	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	$3,180,667	$1,768,730	$34,598	$1,071,174	$69,826	$132,386	[redacted]	[redacted]	$103,953
		Energy	PAY-NRG	PAY-NRG	$776,083	$403,463	$9,335	$284,324	$22,268	$51,535	[redacted]	[redacted]	$4,902
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-4a	Svngs Pln Match on Payroll Inc	Total			$135,349	$76,613	$1,744	$43,250	$2,835	$6,400	[redacted]	[redacted]	$3,266
		Customer	PAY-CUST	PAY-CUST	$16,646	$11,447	$426	$2,585	$72	$882	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	$95,420	$53,062	$1,038	$32,135	$2,095	$3,972	[redacted]	[redacted]	$3,119
		Energy	PAY-NRG	PAY-NRG	$23,283	$12,104	$280	$8,530	$668	$1,546	[redacted]	[redacted]	$147
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-4b	FICA on Payroll Increase	Total			$345,139	$195,362	$4,447	$110,286	$7,228	$16,320	[redacted]	[redacted]	$8,327
		Customer	PAY-CUST	PAY-CUST	$42,447	$29,189	$1,086	$6,591	$183	$2,250	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	$243,321	$135,308	$2,647	$81,945	$5,342	$10,128	[redacted]	[redacted]	$7,952
		Energy	PAY-NRG	PAY-NRG	$59,370	$30,865	$714	$21,751	$1,703	$3,942	[redacted]	[redacted]	$375
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-5	Reclass G/L on Reaquired Debt	Total			$638,187	$368,367	$6,590	$199,134	$12,721	$12,689	[redacted]	[redacted]	$37,431
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$74,436	$57,644	$1,149	$13,276	$126	$985	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$479,240	$266,277	$4,404	$153,269	$10,003	$8,419	[redacted]	[redacted]	$36,867
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$84,511	$44,446	$1,037	$32,589	$2,592	$3,284	[redacted]	[redacted]	$564
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-6	BPU & RPA Assessments	Total			($425,441)	($222,236)	($4,991)	($140,728)	($8,717)	($19,893)	[redacted]	[redacted]	($13,976)
		Customer	DIST-REV-CUST	DIST-REV-CUST	($32,852)	($24,279)	($695)	($7,282)	($74)	($196)	[redacted]	[redacted]	$0
		Demand	DIST-REV-DMD	DIST-REV-DMD	($118,322)	$0	$0	($74,631)	($6,833)	($15,428)	[redacted]	[redacted]	($10,062)
		Energy	DIST-REV-NRG	DIST-REV-NRG	($274,267)	($197,957)	($4,296)	($58,815)	($1,810)	($4,270)	[redacted]	[redacted]	($3,914)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-7	Return Net Gain on Sale of Property	Total			($101,996)	($58,873)	($1,053)	($31,826)	($2,033)	($2,028)	[redacted]	[redacted]	($5,982)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($11,896)	($9,213)	($184)	($2,122)	($20)	($157)	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($76,593)	($42,557)	($704)	($24,496)	($1,599)	($1,346)	[redacted]	[redacted]	($5,892)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($13,507)	($7,103)	($166)	($5,208)	($414)	($525)	[redacted]	[redacted]	($90)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-8	Rate Case Exp	Total			$156,039	$81,271	$1,390	$47,594	$3,327	$9,616	[redacted]	[redacted]	$1,073
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$122,802	$66,298	$1,041	$36,616	$2,454	$6,904	[redacted]	[redacted]	$883
		Energy	AE-ALL-NRG	NRG-ALL	$33,237	$14,973	$349	$10,978	$873	$2,712	[redacted]	[redacted]	$190

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-9	OPEB Settlement	Total			$1,187,500	$672,172	$15,301	$379,456	$24,870	$56,150	[redacted]	[redacted]	$28,652
		Customer	PAY-CUST	PAY-CUST	$146,047	$100,430	$3,738	$22,677	$630	$7,741	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	$837,181	$465,546	$9,106	$281,943	$18,379	$34,845	[redacted]	[redacted]	$27,361
		Energy	PAY-NRG	PAY-NRG	$204,272	$106,195	$2,457	$74,837	$5,861	$13,564	[redacted]	[redacted]	$1,290
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-10a	Pension Smoothing	Total			($25,638,726)	($14,512,528)	($330,360)	($8,192,650)	($536,964)	($1,212,312)	[redacted]	[redacted]	($618,603)
		Customer	PAY-CUST	PAY-CUST	($3,153,220)	($2,168,343)	($80,701)	($489,598)	($13,610)	($167,121)	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	($18,075,166)	($10,051,378)	($196,612)	($6,087,291)	($396,811)	($752,327)	[redacted]	[redacted]	($590,746)
		Energy	PAY-NRG	PAY-NRG	($4,410,341)	($2,292,808)	($53,047)	($1,615,760)	($126,542)	($292,864)	[redacted]	[redacted]	($27,857)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-10b	OPEB Smoothing	Total			$7,176,427	$4,062,140	$92,470	$2,293,170	$150,299	$339,333	[redacted]	[redacted]	$173,151
		Customer	PAY-CUST	PAY-CUST	$882,604	$606,932	$22,589	$137,041	$3,810	$46,778	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	$5,059,343	$2,813,439	$55,033	$1,703,868	$111,070	$210,581	[redacted]	[redacted]	$165,353
		Energy	PAY-NRG	PAY-NRG	$1,234,480	$641,770	$14,848	$452,261	$35,420	$81,974	[redacted]	[redacted]	$7,797
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-11	Normalize Forestry Maint Exp	Total			$5,808,721	$3,435,573	$58,714	$2,010,733	$140,498	$117,857	[redacted]	[redacted]	$45,347
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	OHL-PLT-DMD	OHL-PLT-DMD	$4,631,250	$2,809,376	$44,110	$1,551,595	$103,977	$84,788	[redacted]	[redacted]	$37,405
		Energy	OHL-PLT-NRG	OHL-PLT-NRG	$1,177,470	$626,197	$14,604	$459,139	$36,521	$33,069	[redacted]	[redacted]	$7,941
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-12	Amort Forestry Reg Asset	Total			$2,894,215	$1,711,786	$29,254	$1,001,855	$70,003	$58,723	[redacted]	[redacted]	$22,594
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	OHL-PLT-DMD	OHL-PLT-DMD	$2,307,536	$1,399,781	$21,978	$773,087	$51,807	$42,246	[redacted]	[redacted]	$18,637
		Energy	OHL-PLT-NRG	OHL-PLT-NRG	$586,679	$312,005	$7,276	$228,767	$18,197	$16,477	[redacted]	[redacted]	$3,957
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-13	Annualize Deprec Exp	Total			$17,988,446	$10,146,379	$201,991	$5,403,960	$354,609	$389,622	[redacted]	[redacted]	$1,327,329
		Customer	DPR-TOT-CUST	DPR-TOT-CUST	$2,154,997	$1,655,880	$44,503	$296,516	$5,617	$67,048	[redacted]	[redacted]	$0
		Demand	DPR-TOT-DMD	DPR-TOT-DMD	$13,575,697	$7,316,306	$130,104	$4,246,505	$280,511	$231,970	[redacted]	[redacted]	$1,312,437
		Energy	DPR-TOT-NRG	DPR-TOT-NRG	$2,257,751	$1,174,193	$27,384	$860,939	$68,481	$90,604	[redacted]	[redacted]	$14,891
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-14	Average Net Salvage	Total			$7,788,834	$4,495,780	$80,425	$2,430,358	$155,257	$154,859	[redacted]	[redacted]	$456,832
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$908,458	$703,521	$14,020	$162,033	$1,536	$12,025	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$5,848,951	$3,249,811	$53,754	$1,870,592	$122,084	$102,757	[redacted]	[redacted]	$449,953
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$1,031,425	$542,449	$12,651	$397,733	$31,636	$40,077	[redacted]	[redacted]	$6,879
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-15	Amort Storm Damage Exp	Total			$76,863,146	$40,033,238	$684,762	$23,444,410	$1,638,832	$4,736,926	[redacted]	[redacted]	$528,355
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$60,490,894	$32,657,902	$512,759	$18,036,683	$1,208,691	$3,400,864	[redacted]	[redacted]	$434,821
		Energy	AE-ALL-NRG	NRG-ALL	$16,372,252	$7,375,336	$172,003	$5,407,727	$430,141	$1,336,062	[redacted]	[redacted]	$93,534
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-16	ServCo Depr @ JCP&L Rates	Total			$1,710,308	$890,793	$15,237	$521,669	$36,466	$105,403	[redacted]	[redacted]	$11,757
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	DPR-G&I-DMD	DMD-ALL	$1,346,003	$726,682	$11,410	$401,340	$26,895	$75,674	[redacted]	[redacted]	$9,675
		Energy	DPR-G&I-NRG	NRG-ALL	$364,304	$164,111	$3,827	$120,329	$9,571	$29,729	[redacted]	[redacted]	$2,081
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-17	SERP/EDCP	Total			($1,181,606)	($668,835)	($15,225)	($377,573)	($24,747)	($55,872)	[redacted]	[redacted]	($28,509)
		Customer	PAY-CUST	PAY-CUST	($145,322)	($99,932)	($3,719)	($22,564)	($627)	($7,702)	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	($833,026)	($463,235)	($9,061)	($280,544)	($18,288)	($34,672)	[redacted]	[redacted]	($27,226)
		Energy	PAY-NRG	PAY-NRG	($203,258)	($105,668)	($2,445)	($74,465)	($5,832)	($13,497)	[redacted]	[redacted]	($1,284)

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
ADJ-18	Removal of Certain Advertising Expense	Total			($924,095)	($519,748)	($8,880)	($304,141)	($21,249)	($61,399)	[redacted]	[redacted]	($6,860)
		Customer	A&G-GT-CUST	CUST-GTA&G	($1,818)	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	($732,560)	($425,300)	($6,678)	($234,890)	($15,741)	($44,289)	[redacted]	[redacted]	($5,663)
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	($189,717)	($94,448)	($2,203)	($69,251)	($5,508)	($17,110)	[redacted]	[redacted]	($1,198)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-19	Holding Company Costs	Total			$147,821	$83,140	$1,421	$48,651	$3,399	$9,822	[redacted]	[redacted]	$1,097
		Customer	A&G-GT-CUST	CUST-GTA&G	$291	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$117,182	$68,032	$1,068	$37,574	$2,518	$7,085	[redacted]	[redacted]	$906
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$30,348	$15,108	$352	$11,078	$881	$2,737	[redacted]	[redacted]	$192
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-20	ARAM	Total			$131,215	$75,738	$1,355	$40,943	$2,616	$2,609	[redacted]	[redacted]	$7,696
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$15,304	$11,852	$236	$2,730	$26	$203	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$98,535	$54,748	$906	$31,513	$2,057	$1,731	[redacted]	[redacted]	$7,580
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$17,376	$9,138	$213	$6,700	$533	$675	[redacted]	[redacted]	$116
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-21	LED Amortization	Total			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Energy	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-22	Production Related Regulatory Asset Amortization	Total			$1,211,786	$631,144	$10,796	$369,613	$25,837	$74,680	[redacted]	[redacted]	$8,330
		Customer	NONE	NONE	$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-ALL-DMD	DMD-ALL	$953,669	$514,868	$8,084	$284,357	$19,056	$53,616	[redacted]	[redacted]	$6,855
		Energy	AE-ALL-NRG	NRG-ALL	$258,117	$116,276	$2,712	$85,256	$6,781	$21,064	[redacted]	[redacted]	$1,475
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-23	Service Company O&M	Total			$3,407,305	$1,916,405	$32,743	$1,121,422	$78,349	$226,388	[redacted]	[redacted]	$25,296
		Customer	A&G-GT-CUST	CUST-GTA&G	$6,703	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand	AE-PRI-DMD-GTA&G	DMD-PRI	$2,701,080	$1,568,159	$24,622	$866,081	$58,039	$163,302	[redacted]	[redacted]	$20,879
		Energy	AE-PRI-NRG-GTA&G	NRG-PRI	$699,522	$348,247	$8,122	$255,341	$20,310	$63,086	[redacted]	[redacted]	$4,416
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
PTYADDS	RB Post Test-Year Additions 6mo CAPEX	Total			$30,013,986	$17,324,323	$309,916	$9,365,296	$598,278	$596,742	[redacted]	[redacted]	$1,760,386
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$3,500,711	$2,710,991	$54,026	$624,390	$5,920	$46,339	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$22,538,717	$12,523,026	$207,141	$7,208,256	$470,447	$395,969	[redacted]	[redacted]	$1,733,877
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$3,974,558	$2,090,306	$48,749	$1,532,650	$121,910	$154,434	[redacted]	[redacted]	$26,509
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
PTYDPRRES	RB Post Test-Year Deprec Reserve 6mo CAPEX	Total			($663,309)	($382,868)	($6,849)	($206,973)	($13,222)	($13,188)	[redacted]	[redacted]	($38,905)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($77,366)	($59,913)	($1,194)	($13,799)	($131)	($1,024)	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($498,106)	($276,759)	($4,578)	($159,302)	($10,397)	($8,751)	[redacted]	[redacted]	($38,319)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($87,838)	($46,196)	($1,077)	($33,872)	($2,694)	($3,413)	[redacted]	[redacted]	($586)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-IIPADD	RB IIP Incremental Plant Additions	Total			$31,402,232	$18,125,630	$324,250	$9,798,472	$625,950	$624,344	[redacted]	[redacted]	$1,841,810
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	$3,662,630	$2,836,383	$56,525	$653,270	$6,194	$48,482	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	$23,581,207	$13,102,257	$216,722	$7,541,662	$492,207	$414,284	[redacted]	[redacted]	$1,814,075
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	$4,158,395	$2,186,990	$51,004	$1,603,540	$127,549	$161,577	[redacted]	[redacted]	$27,735
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-IIPDEP	RB IIP Incremental Deprec Reserve	Total			(758,683)	($437,918)	($7,834)	($236,733)	($15,123)	($15,084)	[redacted]	[redacted]	($44,498)
		Customer	DIST-PLT-CUST	DIST-PLT-CUST	($88,490)	($68,527)	($1,366)	($15,783)	($150)	($1,171)	[redacted]	[redacted]	$0
		Demand	DIST-PLT-DMD	DIST-PLT-DMD	($569,726)	($316,553)	($5,236)	($182,208)	($11,892)	($10,009)	[redacted]	[redacted]	($43,828)
		Energy	DIST-PLT-NRG	DIST-PLT-NRG	($100,467)	($52,838)	($1,232)	($38,742)	($3,082)	($3,904)	[redacted]	[redacted]	($670)

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Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
RB-P&OPEBADD	RB Delayed Recog Pension & OPEB Additions	Total			($68,892,010)	($38,995,590)	($887,688)	($22,013,891)	($1,442,837)	($3,257,519)	[redacted]	[redacted]	($1,662,205)
		Customer	PAY-CUST	PAY-CUST	($8,472,793)	($5,826,400)	($216,846)	($1,315,565)	($36,571)	($449,060)	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	($48,568,502)	($27,008,348)	($528,303)	($16,356,730)	($1,066,243)	($2,021,525)	[redacted]	[redacted]	($1,587,353)
		Energy	PAY-NRG	PAY-NRG	($11,850,715)	($6,160,842)	($142,539)	($4,341,596)	($340,023)	($786,934)	[redacted]	[redacted]	($74,852)
Account	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
RB-P&OPEBDEP	RB Delayed Recog Pension & OPEB Deprec Reserve	Total			$12,716,844	$7,198,234	$163,859	$4,063,566	$266,335	$601,309	[redacted]	[redacted]	$306,828
		Customer	PAY-CUST	PAY-CUST	$1,564,001	$1,075,501	$40,028	$242,841	$6,751	$82,892	[redacted]	[redacted]	$0
		Demand	PAY-DMD	PAY-DMD	$8,965,307	$4,985,497	$97,520	$3,019,305	$196,819	$373,155	[redacted]	[redacted]	$293,011
		Energy	PAY-NRG	PAY-NRG	$2,187,535	$1,137,236	$26,311	$801,419	$62,765	$145,261	[redacted]	[redacted]	$13,817
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-REV	Adjs to Revenue	Total			($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)	[redacted]	[redacted]	($9,867)
		Customer			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
		Demand			($268,082)	($124,582)	($3,340)	($98,758)	($5,998)	($14,766)	[redacted]	[redacted]	($9,867)
		Energy			$0	$0	$0	$0	$0	$0	[redacted]	[redacted]	$0
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-O&M	Adjs to O&M Exp	Total			($3,373,977)	($1,489,797)	($76,120)	($1,164,859)	($69,101)	($308,226)	[redacted]	[redacted]	($260,678)
		Customer			($693,546)	($269,476)	($31,854)	($157,430)	($7,716)	($96,551)	[redacted]	[redacted]	$0
		Demand			($2,026,084)	($799,859)	($35,028)	($823,704)	($50,797)	($153,606)	[redacted]	[redacted]	($254,656)
		Energy			($654,346)	($420,462)	($9,237)	($183,725)	($10,589)	($58,068)	[redacted]	[redacted]	($6,022)
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-AMORT	Adjs to Amortization Exp	Total			$82,185,866	$43,065,205	$740,415	$25,204,451	$1,760,125	$4,927,060	[redacted]	[redacted]	$589,644
		Customer			$149,455	$103,070	$3,790	$23,284	$636	$7,786	[redacted]	[redacted]	$0
		Demand			$64,611,222	$35,050,289	$552,128	$19,383,088	$1,298,390	$3,531,957	[redacted]	[redacted]	$489,362
		Energy			$17,425,189	$7,911,847	$184,496	$5,798,079	$461,099	$1,387,318	[redacted]	[redacted]	$100,282
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-TXOTR	Adjs to Taxes Other Than Income	Total			$345,139	$195,362	$4,447	$110,286	$7,228	$16,320	[redacted]	[redacted]	$8,327
		Customer			$42,447	$29,189	$1,086	$6,591	$183	$2,250	[redacted]	[redacted]	$0
		Demand			$243,321	$135,308	$2,647	$81,945	$5,342	$10,128	[redacted]	[redacted]	$7,952
		Energy			$59,370	$30,865	$714	$21,751	$1,703	$3,942	[redacted]	[redacted]	$375
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
ADJ-DEPRC	Adjs to Depreciation Exp	Total			$25,777,280	$14,642,159	$282,416	$7,834,318	$509,866	$544,481	[redacted]	[redacted]	$1,784,161
		Customer			$3,063,455	$2,359,400	$58,523	$458,550	$7,154	$79,073	[redacted]	[redacted]	$0
		Demand			$19,424,648	$10,566,116	$183,858	$6,117,096	$402,595	$334,727	[redacted]	[redacted]	$1,762,390
		Energy			$3,289,176	$1,716,642	$40,035	$1,258,672	$100,117	$130,681	[redacted]	[redacted]	$21,771
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTEXPADJ	Total Adjustments to Expense	Total			$104,934,308	$56,412,929	$951,158	$31,984,197	$2,208,118	$5,179,635	[redacted]	[redacted]	$2,121,455
		Customer			$2,561,811	$2,222,183	$31,546	$330,995	$257	($7,443)	[redacted]	[redacted]	$0
		Demand			$82,253,107	$44,951,854	$703,605	$24,758,426	$1,655,531	$3,723,205	[redacted]	[redacted]	$2,005,049
		Energy			$20,119,390	$9,238,891	$216,007	$6,894,777	$552,331	$1,463,873	[redacted]	[redacted]	$116,406
Sub-Total	Description	Category	Class Factor	Alloc Factor	Total	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG
TOTRBADJ	Total Rate Base Adjustments	Total			$3,819,060	$2,831,812	($104,346)	$769,737	$19,380	($1,463,397)	[redacted]	[redacted]	$2,163,416
		Customer			$88,693	$668,035	($68,827)	$175,354	($17,987)	($273,542)	[redacted]	[redacted]	$0
		Demand			$5,448,898	$3,009,122	($16,735)	$1,070,983	$70,942	($856,877)	[redacted]	[redacted]	$2,171,463
		Energy			($1,718,532)	($845,344)	($18,785)	($476,600)	($33,575)	($332,978)	[redacted]	[redacted]	($8,047)

REDACTED

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AF	RS	RT	GS	GST	GP	GT	GT-D	LTG
ALL451	0.825	0.008	0.133	0.011	0.003	[redacted]	[redacted]	0.012
ALL901	0.793	0.016	0.183	0.002	0.001	[redacted]	[redacted]	0.003
ALL905	0.793	0.016	0.183	0.002	0.001	[redacted]	[redacted]	0.003
CUST-ALL	0.872	0.013	0.111	0.000	0.000	[redacted]	[redacted]	0.003
CUST-DEP	0.874	0.013	0.111	0.000	0.000	[redacted]	[redacted]	0.000
CUST-GTA&G	0.000	0.000	0.000	0.000	0.000	[redacted]	[redacted]	0.000
CUST-LTG	0.000	0.000	0.000	0.000	0.000	[redacted]	[redacted]	1.000
CUST-MTR	0.692	0.026	0.156	0.004	0.053	[redacted]	[redacted]	0.000
CUST-PRI	0.872	0.013	0.111	0.000	0.000	[redacted]	[redacted]	0.003
CUST-SEC	0.873	0.013	0.111	0.000	0.000	[redacted]	[redacted]	0.003
CUST-SVCS	0.875	0.013	0.111	0.000	0.000	[redacted]	[redacted]	0.000
CWC-CUST	0.693	0.026	0.156	0.004	0.053	[redacted]	[redacted]	0.000
CWC-DMD	0.535	0.012	0.351	0.022	0.025	[redacted]	[redacted]	0.054
CWC-NRG	0.541	0.012	0.368	0.028	0.043	[redacted]	[redacted]	0.006
DIST-PLT-CUST	0.774	0.015	0.178	0.002	0.013	[redacted]	[redacted]	0.000
DIST-PLT-DMD	0.556	0.009	0.320	0.021	0.018	[redacted]	[redacted]	0.077
DIST-PLT-NRG	0.526	0.012	0.386	0.031	0.039	[redacted]	[redacted]	0.007
DIST-REV-CUST	0.739	0.021	0.222	0.002	0.006	[redacted]	[redacted]	0.000
DIST-REV-DMD	0.000	0.000	0.631	0.058	0.130	[redacted]	[redacted]	0.085
DIST-REV-NRG	0.722	0.016	0.214	0.007	0.016	[redacted]	[redacted]	0.014
DMD-ALL	0.540	0.008	0.298	0.020	0.056	[redacted]	[redacted]	0.007
DMD-LTG	0.000	0.000	0.000	0.000	0.000	[redacted]	[redacted]	1.000
DMD-MTR	0.126	0.055	0.781	0.038	0.000	[redacted]	[redacted]	0.000
DMD-PRI	0.581	0.009	0.321	0.021	0.060	[redacted]	[redacted]	0.008
DMD-SEC	0.618	0.010	0.341	0.023	0.000	[redacted]	[redacted]	0.008
DPR-TOT-CUST	0.768	0.021	0.138	0.003	0.031	[redacted]	[redacted]	0.000
DPR-TOT-DMD	0.539	0.010	0.313	0.021	0.017	[redacted]	[redacted]	0.097
DPR-TOT-NRG	0.520	0.012	0.381	0.030	0.040	[redacted]	[redacted]	0.007
LATEPAY	0.000	0.000	0.816	0.029	0.104	[redacted]	[redacted]	0.131
NONE	0.000	0.000	0.000	0.000	0.000	[redacted]	[redacted]	0.000
NRG-ALL	0.450	0.011	0.330	0.026	0.082	[redacted]	[redacted]	0.006
NRG-PRI	0.498	0.012	0.365	0.029	0.090	[redacted]	[redacted]	0.006
NRG-SEC	0.547	0.013	0.401	0.032	0.000	[redacted]	[redacted]	0.007
OHL-PLT-DMD	0.607	0.010	0.335	0.022	0.018	[redacted]	[redacted]	0.008
OHL-PLT-NRG	0.532	0.012	0.390	0.031	0.028	[redacted]	[redacted]	0.007
PAY-CUST	0.688	0.026	0.155	0.004	0.053	[redacted]	[redacted]	0.000
PAY-DMD	0.556	0.011	0.337	0.022	0.042	[redacted]	[redacted]	0.033
PAY-NRG	0.520	0.012	0.366	0.029	0.066	[redacted]	[redacted]	0.006
PWRGD	0.917	0.041	0.042	0.000	0.000	[redacted]	[redacted]	0.000
RB-CUST	0.677	0.017	0.248	0.003	0.024	[redacted]	[redacted]	0.000
RB-DMD	0.555	0.009	0.325	0.021	0.020	[redacted]	[redacted]	0.064
RB-NRG	0.519	0.012	0.380	0.030	0.042	[redacted]	[redacted]	0.007
RB-PLT-CUST	0.774	0.015	0.178	0.002	0.013	[redacted]	[redacted]	0.000
RB-PLT-DMD	0.554	0.009	0.318	0.021	0.021	[redacted]	[redacted]	0.071
RB-PLT-NRG	0.517	0.012	0.379	0.030	0.044	[redacted]	[redacted]	0.007
REV-ALL	0.522	0.012	0.331	0.020	0.047	[redacted]	[redacted]	0.033
SRVC-CUST	0.802	0.012	0.186	0.001	0.000	[redacted]	[redacted]	0.000
SRVC-DMD	0.006	0.000	0.992	0.002	0.000	[redacted]	[redacted]	0.000
SSEQ-PLT-DMD	0.581	0.009	0.321	0.021	0.060	[redacted]	[redacted]	0.008
SSEQ-PLT-NRG	0.498	0.012	0.365	0.029	0.090	[redacted]	[redacted]	0.006
UG-PLT-DMD	0.607	0.010	0.335	0.022	0.018	[redacted]	[redacted]	0.008
UG-PLT-NRG	0.532	0.012	0.390	0.031	0.028	[redacted]	[redacted]	0.007

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ALL451	RS	RT	GS	GST	GP	GT	GT-D	LTG	Total
WP-7	4,256,421	40,846	687,062	54,613	15,742	[redacted]	[redacted]	62,234	5,157,790
Factor	0.825	0.008	0.133	0.011	0 003	[redacted]	[redacted]	0.012	1 000
						[redacted]	[redacted]		
ALL901	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-8	986,002	19,777	227,280	3,077	1,853	[redacted]	[redacted]	3,249	1,242,736
Factor	0.793	0.016	0.183	0.002	0 001	[redacted]	[redacted]	0.003	1 000
						[redacted]	[redacted]		
ALL905	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-8	986,002	19,777	227,280	3,077	1,853	[redacted]	[redacted]	3,249	1,242,736
Factor	0.793	0.016	0.183	0.002	0 001	[redacted]	[redacted]	0.003	1 000
						[redacted]	[redacted]		
CUST-GTA&G	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
						[redacted]	[redacted]		
Factor	0	0	0	0	0	[redacted]	[redacted]	0	1 000
						[redacted]	[redacted]		
CUST-ALL	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-3	986,002	15,213	125,569	197	423	[redacted]	[redacted]	2,938	1,130,506
Factor	0.872	0.013	0.111	0.000	0 000	[redacted]	[redacted]	0.003	1 000
						[redacted]	[redacted]		
CUST-DEP	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-3 (Excl LTG)	986,002	15,213	125,569	197	423	[redacted]	[redacted]		1,127,568
Factor	0.874	0.013	0.111	0.000	0 000	[redacted]	[redacted]	0.000	1 000
						[redacted]	[redacted]		
CUST-LTG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-3						[redacted]	[redacted]	2,938	2,938
Factor	0.000	0.000	0.000	0.000	0 000	[redacted]	[redacted]	1.000	1 000
						[redacted]	[redacted]		
CUST-MTR	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-9/15	101,425,716	3,774,843	22,901,299	636,628	7,817,222	[redacted]	[redacted]	0	146,516,339
Factor	0.692	0.026	0.156	0.004	0 053	[redacted]	[redacted]	0.000	1 000
						[redacted]	[redacted]		
CUST-PRI	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-3	986,002	15,213	125,569	197	423	[redacted]	[redacted]	2,938	1,130,342
Factor	0.872	0.013	0.111	0.000	0 000	[redacted]	[redacted]	0.003	1 000
						[redacted]	[redacted]		
CUST-SEC	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-3	986,002	15,213	125,569	197		[redacted]	[redacted]	2,938	1,129,919
Factor	0.873	0.013	0.111	0.000	0 000	[redacted]	[redacted]	0.003	1 000
						[redacted]	[redacted]		
CUST-SVCS	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-3	986,002	15,213	125,569	197		[redacted]	[redacted]		1,126,981
Factor	0.875	0.013	0.111	0.000	0 000	[redacted]	[redacted]	0.000	1 000
						[redacted]	[redacted]		
CWC-CUST	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
O&M minus A&G	19,514,902	726,302	4,406,344	122,491	1,504,079	[redacted]	[redacted]		28,167,390
Factor	0.693	0.026	0.156	0.004	0 053	[redacted]	[redacted]	0.000	1 000
						[redacted]	[redacted]		
CWC-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
O&M minus A&G	46,453,291	1,078,525	30,479,716	1,942,490	2,188,035	[redacted]	[redacted]	4,730,724	86,872,781
Factor	0.535	0.012	0.351	0.022	0 025	[redacted]	[redacted]	0.054	1 000
						[redacted]	[redacted]		
CWC-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
O&M minus A&G	10,861,999	249,498	7,375,913	568,890	865,329	[redacted]	[redacted]	126,768	20,061,553
Factor	0.541	0.012	0.368	0.028	0 043	[redacted]	[redacted]	0.006	1 000

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DPR-TOT-CUST	RS	RT	GS	GST	GP	GT	GT-D	LTG	Total
Acct 403	11,034,131	296,552	1,975,869	37,432	446,782	[redacted]		0	14,360,051
Factor	0.768	0.021	0.138	0.003	0 031			0.000	1 000
DPR-TOT-DMD	RS	RT	GS	GST	GP			LTG	Total
Acct 403	48,752,979	866,959	28,297,034	1,869,215	1,545,757			8,745,566	90,463,098
Factor	0.539	0.010	0.313	0.021	0 017			0.097	1 000
DPR-TOT-NRG	RS	RT	GS	GST	GP			LTG	Total
Acct 403	7,824,360	182,475	5,736,960	456,329	603,750			99,229	15,044,766
Factor	0.520	0.012	0.381	0.030	0 040			0.007	1 000
DIST-PLT-CUST	RS	RT	GS	GST	GP			LTG	Total
Dist PIS	457,334,072	9,113,983	105,332,251	998,714	7,817,222			0	590,556,873
Factor	0.774	0.015	0.178	0.002	0 013			0.000	1 000
DIST-PLT-DMD	RS	RT	GS	GST	GP			LTG	Total
Dist PIS	2,112,587,836	34,943,872	1,216,006,018	79,362,732	66,798,481			292,498,607	3,802,197,548
Factor	0.556	0.009	0.320	0.021	0 018			0.077	1 000
DIST-PLT-NRG	RS	RT	GS	GST	GP			LTG	Total
Dist PIS	352,626,880	8,223,763	258,552,281	20,565,740	26,052,505			4,472,028	670,493,197
Factor	0.526	0.012	0.386	0.031	0 039			0.007	1 000
DIST-REV-CUST	RS	RT	GS	GST	GP			LTG	Total
WP-4 Dist Revenue	30,980,844	886,940	9,291,578	94,289	250,047			0	41,918,982
Factor	0.739	0.021	0.222	0.002	0 006			0.000	1 000
DIST-REV-DMD	RS	RT	GS	GST	GP			LTG	Total
WP-4 Dist Revenue	0	0	95,229,974	8,719,365	19,685,757			12,839,173	150,980,629
Factor	0.000	0.000	0.631	0.058	0.130			0.085	1 000
DIST-REV-NRG	RS	RT	GS	GST	GP			LTG	Total
WP-4 Dist Revenue	252,595,861	5,482,095	75,049,042	2,309,794	5,448,473			4,994,139	349,969,157
Factor	0.722	0.016	0.214	0.007	0 016			0.014	1 000
DMD-ALL	RS	RT	GS	GST	GP			LTG	Total
WP-12 DMD	3,212,553	50,440	1,774,266	118,899	334,543			42,773	5,950,481
Factor	0.540	0.008	0.298	0.020	0 056			0.007	1 000
DMD-LTG	RS	RT	GS	GST	GP			LTG	Total
WP-12								42,773	42,773
Factor	0.000	0.000	0.000	0.000	0 000			1.000	1 000
DMD-MTR	RS	RT	GS	GST	GP			LTG	Total
WP-9/15	4,265,815	1,842,773	26,347,041	1,292,271	0			0	33,747,900
Factor	0.126	0.055	0.781	0.038	0 000			0.000	1 000

REDACTED

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DMD-PRI	RS	RT	GS	GST	GP	GT	GT-D	LTG	Total
WP-12	3,212,553	50,440	1,774,266	118,899	334,543	[redacted]	[redacted]	42,773	5,533,474
Factor	0.581	0.009	0.321	0.021	0 060	[redacted]	[redacted]	0.008	1 000

DMD-SEC	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-12	3,212,553	50,440	1,774,266	118,899		[redacted]	[redacted]	42,773	5,198,931
Factor	0.618	0.010	0.341	0.023	0 000	[redacted]	[redacted]	0.008	1 000

LATEPAY	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Forfeited Discnt (WP-7)	347	0	1,833,682	65,385	234,858	[redacted]	[redacted]	293,510	2,247,882
Factor	0.000	0.000	0.816	0.029	0.104	[redacted]	[redacted]	0.131	1 000

NRG-ALL	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-2	10,003,450	233,295	7,334,707	583,417	1,812,153	[redacted]	[redacted]	126,864	22,206,312
Factor	0.450	0.011	0.330	0.026	0 082	[redacted]	[redacted]	0.006	1 000

NRG-PRI	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-2	10,003,450	233,295	7,334,707	583,417	1,812,153	[redacted]	[redacted]	126,864	20,093,885
Factor	0.498	0.012	0.365	0.029	0 090	[redacted]	[redacted]	0.006	1 000

NRG-SEC	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-2	10,003,450	233,295	7,334,707	583,417		[redacted]	[redacted]	126,864	18,281,733
Factor	0.547	0.013	0.401	0.032	0 000	[redacted]	[redacted]	0.007	1 000

OHL-PLT-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
OH Lines Plt - 364, 365	936,794,229	14,708,519	517,383,533	34,671,383	28,272,807	[redacted]	[redacted]	12,472,862	1,544,303,333
Factor	0.607	0.010	0.335	0.022	0 018	[redacted]	[redacted]	0.008	1 000

OHL-PLT-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
OH Lines Plt - 364, 365	208,807,075	4,869,679	153,101,049	12,177,949	11,026,859	[redacted]	[redacted]	2,648,099	392,630,711
Factor	0.532	0.012	0.390	0.031	0 028	[redacted]	[redacted]	0.007	1 000

PAY-CUST	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
S&W Alloc * O&M Cust	6,896,209	256,662	1,557,121	43,286	531,514	[redacted]	[redacted]	0	10,028,517
Factor	0.688	0.026	0.155	0.004	0 053	[redacted]	[redacted]	0.000	1 000

PAY-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
S&W Alloc * O&M DMD	31,967,460	625,307	19,360,055	1,262,020	2,392,705	[redacted]	[redacted]	1,878,813	57,486,361
Factor	0.556	0.011	0.337	0.022	0 042	[redacted]	[redacted]	0.033	1 000

PAY-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
S&W Alloc * O&M NRG	7,292,060	168,712	5,138,774	402,456	931,426	[redacted]	[redacted]	88,596	14,026,672
Factor	0.520	0.012	0.366	0.029	0 066	[redacted]	[redacted]	0.006	1 000

PWRGD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-11 Pwr Guard Rev	251,400	11,170	11,650			[redacted]	[redacted]		274,221
Factor	0.917	0.041	0.042	0.000	0 000	[redacted]	[redacted]	0.000	1 000

RB-CUST	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Total Rate Base	149,995,145	3,725,948	55,003,041	684,147	5,396,188	[redacted]	[redacted]	0	221,621,793
Factor	0.677	0.017	0.248	0.003	0 024	[redacted]	[redacted]	0.000	1 000

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RB-DMD	RS	RT	GS	GST	GP	GT	GT-D	LTG	Total
Total Rate Base	1,109,288,261	18,649,486	649,103,894	41,875,045	40,243,774	[redacted]	[redacted]	128,326,354	1,998,401,970
Factor	0.555	0.009	0.325	0.021	0 020	[redacted]	[redacted]	0.064	1 000
RB-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Total Rate Base	196,724,653	4,585,770	143,913,890	11,437,255	15,732,218	[redacted]	[redacted]	2,488,743	378,900,030
Factor	0.519	0.012	0.380	0.030	0 042	[redacted]	[redacted]	0.007	1 000
RB-PLT-CUST	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Rate Base Plt (D,G,I, PTY)	460,045,063	9,168,009	105,956,641	1,004,634	7,863,561	[redacted]	[redacted]	0	594,057,584
Factor	0.774	0.015	0.178	0.002	0 013	[redacted]	[redacted]	0.000	1 000
RB-PLT-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Rate Base Plt (D,G,I, PTY)	2,312,394,820	38,091,541	1,326,649,621	86,764,684	86,697,456	[redacted]	[redacted]	296,726,060	4,171,634,666
Factor	0.554	0.009	0.318	0.021	0 021	[redacted]	[redacted]	0.071	1 000
RB-PLT-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Rate Base Plt (D,G,I, PTY)	397,012,681	9,258,903	291,096,737	23,154,388	33,868,885	[redacted]	[redacted]	5,034,930	768,358,056
Factor	0.517	0.012	0.379	0.030	0 044	[redacted]	[redacted]	0.007	1 000
REV-ALL	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Dist Revenues	283,576,706	6,369,034	179,570,595	11,123,447	25,384,277	[redacted]	[redacted]	17,833,311	542,868,768
Factor	0.522	0.012	0.331	0.020	0 047	[redacted]	[redacted]	0.033	1 000
SRVC-CUST	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-18	355,908,356	5,339,140	82,430,952	362,086	0	[redacted]	[redacted]	0	444,040,534
Factor	0.802	0.012	0.186	0.001	0 000	[redacted]	[redacted]	0.000	1 000
SRVC-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
WP-18	164,940	1,121	25,341,645	46,154	0	[redacted]	[redacted]	0	25,553,860
Factor	0.006	0.000	0.992	0.002	0 000	[redacted]	[redacted]	0.000	1 000
SSEQ-PLT-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Sub St Equip PIS - 362	242,937,174	3,814,334	134,172,147	8,991,268	25,298,510	[redacted]	[redacted]	3,234,565	418,447,998
Factor	0.581	0.009	0.321	0.021	0 060	[redacted]	[redacted]	0.008	1 000
SSEQ-PLT-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
Sub St Equip PIS - 362	54,466,928	1,270,247	39,936,118	3,176,595	9,866,834	[redacted]	[redacted]	690,752	109,407,473
Factor	0.498	0.012	0.365	0.029	0 090	[redacted]	[redacted]	0.006	1 000
UG-PLT-DMD	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
UG Lines Plt - 366, 367	356,871,552	5,603,207	197,097,141	13,208,055	10,770,519	[redacted]	[redacted]	4,751,534	588,302,009
Factor	0.607	0.010	0.335	0.022	0 018	[redacted]	[redacted]	0.008	1 000
UG-PLT-NRG	RS	RT	GS	GST	GP	[redacted]	[redacted]	LTG	Total
UG Lines Plt - 366, 367	79,545,008	1,855,103	58,323,811	4,639,187	4,200,680	[redacted]	[redacted]	1,008,793	149,572,581
Factor	0.532	0.012	0.390	0.031	0 028	[redacted]	[redacted]	0.007	1 000

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CF	Factor
A&G-GT-CUST	0.002
AE-ALL-DMD	0.787
AE-ALL-NRG	0.213
AE-PRI-DMD	0.793
AE-PRI-DMD-GTA&G	0.793
AE-PRI-NRG	0.207
AE-PRI-NRG-GTA&G	0.205
AE-SEC-DMD	0.799
AE-SEC-NRG	0.201
CUST	1.000
CWC-CUST	0.209
CWC-DMD	0.643
CWC-NRG	0.148
DIST-CLA-DMD	0.850
DIST-CLA-NRG	0.150
DIST-PLT-CUST	0.117
DIST-PLT-DMD	0.751
DIST-PLT-NRG	0.132
DIST-REV-CUST	0.077
DIST-REV-DMD	0.278
DIST-REV-NRG	0.645
DMD	1.000
DPR-G&I-DMD	0.787
DPR-G&I-NRG	0.213
DPR-TOT-CUST	0.120
DPR-TOT-DMD	0.755
DPR-TOT-NRG	0.126
MTR-CUST	0.813
MTR-DMD	0.187
NONE	0.000
NRG	1.000
OHL-PLT-DMD	0.797
OHL-PLT-NRG	0.203
PAY-CUST	0.123
PAY-DMD	0.705
PAY-NRG	0.172
RB-CUST	0.085
RB-DMD	0.769
RB-NRG	0.146
RB-PLT-CUST	0.107
RB-PLT-DMD	0.754
RB-PLT-NRG	0.139
SRVC-CUST	0.946
SRVC-DMD	0.054
SSEQ-PLT-DMD	0.793
SSEQ-PLT-NRG	0.207
UG-PLT-DMD	0.797
UG-PLT-NRG	0.203

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		Customer	Demand	Energy	Total
Avg/Excess All	Dist - All		*See WP-13 Avg-Exc Detail Tab*		
WP-13	AE-ALL-***	0 0%	78.7%	21.3%	100 0%
		Customer	Demand	Energy	Total
Avg/Excess Primary	Dist - Primary		*See WP-13 Avg-Exc Detail Tab*		
WP-13	AE-PRI-***	0 0%	79 3%	20.7%	100 0%
		Customer	Demand	Energy	Total
Avg/Exc Secondary	Dist - Secondary		*See WP-13 Avg-Exc Detail Tab*		
WP-13	AE-SEC-***	0 0%	79 9%	20.1%	100 0%
		Customer	Demand	Energy	Total
Avg/Exc for GT A&G	Dist - Primary		*See WP-13 Avg-Exc Detail Tab*		
WP-13	AE-PRI-***-GTA&G	0.197%	79.3%	20.5%	100 0%
		Customer	Demand	Energy	Total
Cash Working Cap	O&M minus A&G Exp	$28,190,603	$86,872,781	$20,061,553	$135,124,936
	CWC-***	20 9%	64.3%	14.8%	100 0%
		Customer	Demand	Energy	Total
Deprec Exp - G&I	Acct 403 G&I Depr Exp	$0	($189,841,551)	($51,381,846)	($241,223,397)
	DPR-G&I-***	0 0%	78.7%	21.3%	100 0%
		Customer	Demand	Energy	Total
Deprec Exp - Tot	Acct 403 - Depr Exp	$14,360,051	$90,463,098	$15,044,766	$119,867,916
	TOT-DPR-***	12 0%	75.5%	12.6%	100 0%
		Customer	Demand	Energy	Total
Distribution Plant	Dist PIS	$590,556,873	$3,802,197,548	$670,493,197	$5,063,247,618
	DIST-PLT-***	11.7%	75.1%	13.2%	100 0%
		Customer	Demand	Energy	Total
Distribution Revs	Dist Revenues	$41,918,982	$150,980,629	$349,969,157	$542,868,768
WP-4	DIST-REV-***	7.7%	27.8%	64.5%	100 0%
		Customer	Demand	Energy	Total
Meter Expense			*See WP-15 Meter Cost Tab*		
WP-15	MTR-***	81 3%	18.7%	0.0%	100 0%
		Customer	Demand	Energy	Total
Misc Exp	Acct 588	$0	$3,802,197,548	$670,493,197	$4,472,690,745
	DIST-CLA-***	0 0%	85.0%	15.0%	100 0%
		Customer	Demand	Energy	Total
OH Lines - Plant	Acct 364 - 365	$0	$1,544,303,333	$392,630,711	$1,936,934,044
	OH-PLT-***	0 0%	79.7%	20.3%	100 0%
		Customer	Demand	Energy	Total
Payroll & Unemp	Acct 408	$10,028,517	$57,486,361	$14,026,672	$81,541,550
WP-10	PAY-***	12 3%	70.5%	17.2%	100 0%
		Customer	Demand	Energy	Total
Rate Base	Total Rate Base	$221,621,793	$1,998,401,970	$378,900,030	$2,598,923,793
	RB-***	8 5%	76.9%	14.6%	100 0%
		Customer	Demand	Energy	Total
Rate Base Plant	Rate Base Plt (D,G,I, PTY)	$594,057,584	$4,171,634,666	$768,358,056	$5,534,050,306
	RB-PLT-***	10.7%	75.4%	13.9%	100 0%
		Customer	Demand	Energy	Total
Services Plant	Acct 369 - Services	$444,040,534	$25,553,860	$0	$469,594,395
	SRVC-***	94.6%	5.4%	0.0%	100 0%
		Customer	Demand	Energy	Total
Substation Plant	Acct 362 - Sub Equip	$0	$418,447,998	$109,407,473	$527,855,471
	SSEQ-PLT-***	0 0%	79.3%	20.7%	100 0%
		Customer	Demand	Energy	Total
UG Lines - Plant	Acct 366 - 367	$0	$588,302,009	$149,572,581	$737,874,590
	UG-PLT-***	0 0%	79.7%	20.3%	100 0%

Jersey Central Power & Light
Direct Input Sheet
Test Year: July 2019 - June 2020
JCP&L's Proposed Alternative COSS

Account	Description	Total	Primary Factor	Primary	Secondary
108-303	Misc Intangible Plant - Accum Res	($86,519,616)			
108-360	Land & Land Rights - Accum Res	($18,452,898)	41.1%	($7,584,141)	($10,868,757)
108-361	Struct & Impmnts - Accum Res	($14,264,483)	63.3%	($9,029,418)	($5,235,065)
108-362	Station Equip - Accum Res	($194,116,809)	100.0%	($194,116,809)	$0
108-364	Poles, Towers & Fixt - Accum Res	($252,451,123)	30.5%	($76,886,747)	($175,564,376)
108-365	OH Cond & Dev - Accum Res	($183,403,589)	30.5%	($55,857,566)	($127,546,023)
108-366	UG Conduit - Accum Res	($59,519,249)	30.5%	($18,127,237)	($41,392,011)
108-367	UG Cond & Dev - Accum Res	($222,969,186)	30.5%	($67,907,701)	($155,061,485)
108-368	Line Transformers - Accum Res	($289,146,526)			
108-369	Services - Accum Res	($189,580,347)			
108-370	Meters - Accum Res	($35,341,484)			
108-371	Install on Cust Premise - Accum Res	($8,345,814)			
108-373	St Lt & Signal Sys - Accum Res	($86,922,368)			
108-374	Asset Ret Costs - Accum Res	($28,356)			
108-389	Land & Land Rights - Accum Res	($5,722)			
108-390	Struct & Impmnts - Accum Res	($54,183,893)			
108-391	Office Furn & Equip - Accum Res	($6,118,526)			
108-392	Transportation Equip - Accum Res	($3,822,686)			
108-393	Stores Equip - Accum Res	($1,257,964)			
108-394	Tools, Shop & Garage Equip - Accum Res	($10,790,043)			
108-395	Laboratory Equip - Accum Res	($448,981)			
108-396	Power Operated Equip - Accum Res	($2,847,208)			
108-397	Communication Equip - Accum Res	($4,859,396)			
108-398	MISC Equip - Accum Res	($921,377)			
108-399	Other Tangible Property - Accum Res	($614,344)			
SRVCO-PIS	Service Company PIS - Accum Res	(68,833,640)			
301	Organization	$45,044			
302	Franchise and Consents	$15,029			
303	Misc Intangible Plant	$126,008,783			
360	Land & Land Rights	$32,657,627	41.1%	$13,422,285	$19,235,342
361	Struct & Impmnts	$59,700,110	63.3%	$37,790,169	$21,909,940
362	Station Equip	$527,855,471	100.0%	$527,855,471	$0
364	Poles, Towers & Fixtures	$753,081,665	30.5%	$229,359,247	$523,722,418
365	OH Cond & Dev	$1,183,852,378	30.5%	$360,555,173	$823,297,205
366	UG Conduit	$117,207,235	30.5%	$35,696,744	$81,510,491
367	UG Cond & Dev	$620,667,356	30.5%	$189,031,023	$431,636,333
368	Line Transformers	$853,891,746			
369	Services	$469,594,395			
370	Meters	$180,264,239			
371	Install on Cust Premise	$25,980,444			
373	St Lt & Signal Sys	$238,449,297			
374	Asset Retirement Costs	$45,657			
389	Land & Land Rights	$1,494,290			
390	Struct & Impmnts	$92,717,272			
391	Office Furn & Equip	$29,278,765			
392	Transportation Equip	$8,780,078			
393	Stores Equip	$1,490,362			
394	Tools, Shop & Garage Equip	$23,055,243			
395	Laboratory Equip	$448,981			
396	Power Operated Equip	$3,851,265			
397	Communication Equip	$36,284,526			
398	MISC Equip	$1,384,722			
399	Other Tangible Property	$1,458,070			
SRVCO-PIS	Service Company PIS	114,476,272			
RB-CUSTDEP	Acct 235 - Cust Deposits	($47,386,955)			
RB-CAFC	Acct 252 - Cust Adv for Const	($34,598,405)			
RB-ADIT	Accum Deferred Inc Tx	($1,102,329,656)			
RB-REAQDBT	Unamort G/L on Reaquired Debt	$2,178,358			
RB-M&S	Materials & Supplies	$22,844,588			
RB-CWC	Cash Working Capital	$114,525,841			

Jersey Central Power & Light
Direct Input Sheet
Test Year: July 2019 - June 2020
JCP&L's Proposed Alternative COSS

Account	Description	Total	Primary Factor	Primary	Secondary
RB-EXCOR	Unamort Excess Cost of Removal	($87,758,072)			
RB-REF	Customer Refunds	($4,033,419)			
RB-OPRES	Net Operating Reserves	($10,699,965)			
RB-NOL	NOL	$22,826,438			
RB-CTA	CTA	($20,787,390)			
RB-PRAMT	Property-Related Unprotected Amort	$32,052,681			
403-360	Land & Land Rights - Deprec Exp	$192,735	41.1%	$79,214	$113,521
403-361	Struct & Impmnts - Deprec Exp	$675,035	63.3%	$427,297	$247,738
403-362	Station Equip - Deprec Exp	$7,538,342	100.0%	$7,538,342	$0
403-364	Poles, Towers & Fixt - Deprec Exp	$18,158,038	30.5%	$5,530,229	$12,627,809
403-365	OH Cond & Dev - Deprec Exp	$26,911,530	30.5%	$8,196,200	$18,715,329
403-366	UG Conduit - Deprec Exp	$1,501,346	30.5%	$457,251	$1,044,095
403-367	UG Cond & Dev - Deprec Exp	$11,717,310	30.5%	$3,568,635	$8,148,675
403-368	Line Transformers - Deprec Exp	$21,448,336			
403-369	Services - Deprec Exp	$6,330,609			
403-370	Meters - Deprec Exp	$10,302,747			
403-371	Install on Cust Premise - Deprec Exp	$910,175			
403-373	St Lt & Signal Sys - Deprec Exp	$7,189,520			
403-374	Asset Retirement Costs - Deprec Exp	$850			
403-389	Land & Land Rights - Deprec Exp	$377			
403-390	Struct & Impmnts - Deprec Exp	$1,494,037			
403-391	Office Furn & Equip - Deprec Exp	$1,903,796			
403-392	Transportation Equip - Deprec Exp	$535,910			
403-393	Stores Equip - Deprec Exp	$44,353			
403-394	Tools, Shop & Garage Equip - Deprec Exp	$1,215,535			
403-396	Power Operated Equip - Deprec Exp	$16,999			
403-397	Communication Equip - Deprec Exp	$1,691,857			
403-398	MISC Equip - Deprec Exp	$17,967			
403-399	Other Tangible Property - Deprec Exp	$70,511			
404	Amort - Ltd Term Elec Prpty	$8,815,151			
407-TMI/OC	Amort - TMI and OC	$109,008			
407-STRM	Amort - Storm Exp	$25,566,878			
407-COR	Amort - Cost of Removal	($3,124,154)			
407-ARO	Amort - ARO ACCR & DEP	($9,421,269)			
411.1	Accretion Expense	$9,380,189			
408-PPTYTX	Txs Otr Inc - Property Tax	$4,935,959			
408-PAY	Txs Otr Inc - Payroll & Unemp	$4,621,369			
REV	Rev - Retail Distribution	$542,868,768			
450	Rev - Elec Frft Discount	$2,247,882			
451	Rev - Misc Service	$5,157,789			
454	Rev - Rent from Elec Prpty	$6,481,819			
456PG	Other Elec Revs - Pwr Guard	$1,655,608			
524	Misc Nuclear Pwr Exp	$0			
580	OP Supv & Eng	$89,279	30.2%	$26,941	$62,338
581	Load Dispatching	$1,283,749			
582	Station Exp	$586,634	100.0%	$586,634	$0
583	OH Line Exp	$1,386,851	30.5%	$422,381	$964,470
584	UG Line Exp	$3,370,232	30.5%	$1,026,441	$2,343,791
585	St Lt & Signal Sys Exp	$0			
586	Meter Exp	$1,124,469			
588	Misc Exp	17,308,525			
589	Rent	6,177,282	30.2%	$1,864,096	$4,313,186
590	Maint Supv & Engr	1,617,484	30.2%	$488,102	$1,129,382
591	Maint of Structures	119,074			
592	Maint of Station Equip	10,654,296	100.0%	$10,654,296	$0
593	Maint of OH Lines	36,695,799	30.5%	$11,176,107	$25,519,693
594	Maint of UG Lines	3,597,029	30.5%	$1,095,515	$2,501,515
595	Maint of Line Trnsfrmrs	350,274			
596	Maint of St Lt & Signal Sys	3,006,789			
597	Maint of Meters	4,870,664			
598	Maint of Misc Dist Plant	1,578,429			
901	Supervision	$38,021			
902	Meter Reading Exp	$14,235,371			
903	Cust Records & Collect Exp	$14,453,393			

Jersey Central Power & Light
Direct Input Sheet
Test Year: July 2019 - June 2020
JCP&L's Proposed Alternative COSS

Account	Description	Total	Primary Factor	Primary	Secondary
904	Cust Uncollect Exp	$119,609			
905	Misc Cust Acct Exp	$1,436,938			
907	Supervision	$368,340			
908	Cust Assist Exp	$1,214,314			
909	Info & Instrctnl Advertising	$2,400			
910	Misc Cust Srvc & Info Exp	$9,383,308			
911	Sales Exp	$56,383			
920	A&G Salaries	$850,366			
921	Office Supplies & Exp	$1,085,146			
922	Admin Exp Trnsfr Credit	$0			
923	Outside Services	$32,961,974			
924	Property Insurance	$253,345			
925	Injuries & Damages	$3,344,187			
926	Pensions & Benefits	$44,294,361			
928	Regulatory Comms Exp	$4,483,645			
930.1	Gen Advertising Exp	$996,585			
930.2	Misc Gen Exp	$2,279,321			
931	Rents	$2,510,095			
935	Maint of Gen Plant	$2,562,438			
INTEXP	Interest Expense	$62,352,756			
STTXEXP	State Income Tax Rate	9.0%			
FEDTXEXP	Federal Income Tax Rate	21.0%			
	Composite Tax Gross-up Factor	1.391			
FEDITC	Amortization of Fed Income Tax Credit	(97,625)			
FEDTAXRFM	Federal Tax Reform Amortization	(5,291,287)			
ADJ-1	Revenue Normalization	($319,110)			
ADJ-2	Tariff Fee Adjustments	$51,028			
ADJ-3	Int on Cust Deposits	1,104,116			
ADJ-4	Annualize Payroll Increase	$4,511,619			
ADJ-4a	Svngs Pln Match on Payroll Inc	135,349			
ADJ-4b	FICA on Payroll Increase	$345,139			
ADJ-5	Reclass G/L on Reaquired Debt	638,187			
ADJ-6	BPU & RPA Assessments	($425,441)			
ADJ-7	Return Net Gain on Sale of Property	($101,996)			
ADJ-8	Rate Case Exp	$156,039			
ADJ-9	OPEB Settlement	$1,187,500			
ADJ-10a	Pension Smoothing	($25,638,726)			
ADJ-10b	OPEB Smoothing	$7,176,427			
ADJ-11	Normalize Forestry Maint Exp	$5,808,721			
ADJ-12	Amort Forestry Reg Asset	$2,894,215			
ADJ-13	Annualize Deprec Exp	$17,988,446			
ADJ-14	Average Net Salvage	$7,788,834			
ADJ-15	Amort Storm Damage Exp	$76,863,146			
ADJ-16	ServCo Depr @ JCP&L Rates	$1,710,308			
ADJ-17	SERP/EDCP	($1,181,606)			
ADJ-18	Removal of Certain Advertising Expense	($924,095)			
ADJ-19	Holding Company Costs	$147,821			
ADJ-20	ARAM	$131,215			
ADJ-21	LED Amortization	$0			
ADJ-22	Production Related Regulatory Asset Amortizatic	$1,211,786			
ADJ-23	Service Company O&M	$3,407,305			
PTYADDS	RB Post Test-Year Additions- 6mo CAPEX	$30,013,986			
PTYDPRRES	RB Post Test-Year Deprec Reserve- 6mo CAPEX	($663,309)			
RB-IIPADD	RB IIP Incremental Plant Additions	$31,402,232			
RB-IIPDEP	RB IIP Incremental Deprec Reserve	(758,683)			
RB-P&OPEBADD	RB Delayed Recog Pension & OPEB Additions	($68,892,010)			
RB-P&OPEBDEP	RB Delayed Recog Pension & OPEB Deprec Reser	$12,716,844			
Dist Rev Change	RS Change in Dist Rev	$102,458,038			
Dist Rev Change	RT Change in Dist Rev	$2,080,000			
Dist Rev Change	GS Change in Dist Rev	$61,580,000			
Dist Rev Change	GST Change in Dist Rev	$4,040,000			
Dist Rev Change	GP Change in Dist Rev	$7,850,000			
Dist Rev Change	GT Change in Dist Rev	$5,788,000			
Dist Rev Change	GT-D Change in Dist Rev	$89,900			
Dist Rev Change	LTG Change in Dist Rev	$3,060,000			
	Required Rate of Return	7.76%			

Jersey Central Power & Light
WP-1 Average Monthly Coincident Peak Demands (CP)
June - September 2019

Coincident Peak Demands June-September 2019 (MWs)	
Rate Class	CP (MWs)
RS	3,110,797
RT	49,303
GS	1,356,865
GST	98,494
GP	286,892
GT	[redacted]
GT-D	[redacted]
Lighting	484
Total	5,197,613

Jersey Central Power & Light
WP-2 Weather Adjusted Billing Month Delivery Net System Requirements (NSRs) in MWH by Load Study Group {1}
July 2019 - June 2020 (2019-2020 6+6)

Test Year Net System Requirements by Rate Class	
Rate Class	NSR[1] (MWhs)
RS	10,003,450
RT	233,295
GS	7,334,707
GST	583,417
GP	1,812,153
GT	[redacted]
GT-D	[redacted]
Lighting	126,864
Total	22,206,312

(1) NSRs are derived by applying loss factors to weather-adjusted sales by voltage level (i.e., secondary, primary, transmission)

Jersey Central Power & Light
WP-3 Average Customer Counts
July 2019 - June 2020 (2019-2020 6+6)

Test Year Customer Counts	
Rate Class	Average Customer Count
RS	986,002
RT	15,213
GS	125,569
GST	197
GP	423
GT	[redacted]
GT-D	[redacted]
Lighting	2,938
Total	1,130,506

Jersey Central Power & Light
WP-4 Weather Normalized Billing Month Distribution Revenue
July 2019 - June 2020 (2019-2020 6+6)

Rate Class	Revenue Year	Customer	kWh	Demand	kVar	Fixtures & Misc	Total Distribution
RS	$ 9,069,311,110	$ 30,980,844	$ 252,595,861	$ -	$ -	$ -	$ 283,576,705
RT	211,509,297	886,940	5,482,095	-	-	-	6,369,034
GS	6,649,779,713	9,291,578	75,049,042	95,229,974	-	-	179,570,595
GST	528,936,132	94,289	2,309,794	8,719,365	-	-	11,123,447
GP	1,730,804,795	250,047	5,448,473	19,069,124	616,633	-	25,384,277
GT	[redacted]						
GT-D							
Lighting	115,683,995	-	4,994,139	-	-	12,839,173	17,833,311
Company Total	**$ 20,375,113,427**	**$ 41,918,982**	**$ 349,969,157**	**$ 136,900,122**	**$ 1,241,333**	**$ 12,839,173**	**$ 542,868,768**

Account	Description	Category	Total	RS	RT	GS	GST	GP	GT	GT-D	LTG
REV	Rev - Retail Distribution	Total	$542,868,768	$283,576,705	$6,369,034	$179,570,595	$11,123,447	$25,384,277	[redacted]		$ 17,833,311
		Customer	$41,918,982	30,980,844	$886,940	$9,291,578	$94,289	$250,047			$ -
		Demand	$150,980,629	$0	$0	$95,229,974	$8,719,365	$19,685,757			$ 12,839,173
		Energy	$349,969,157	$252,595,861	5,482,095	$75,049,042	$2,309,794	$5,448,473			$ 4,994,139

Jersey Central Power & Light
WP-5 BPU Staff Primary/Secondary Segmentation

FERC Account	Primary %	Secondary %
360	50%	50%
361	50%	50%
362	50%	50%
364	50%	50%
365	50%	50%
366	90%	10%
367	50%	50%

Original Investment	Total $	Primary $	Secondary $
360	$ 32,657,627	$ 16,328,813	$ 16,328,813
361	$ 59,700,110	$ 29,850,055	$ 29,850,055
362	$ 527,855,471	$ 263,927,736	$ 263,927,736
364	$ 753,081,665	$ 376,540,833	$ 376,540,833
365	$ 1,183,852,378	$ 591,926,189	$ 591,926,189
366	$ 117,207,235	$ 105,486,511	$ 11,720,723
367	$ 620,667,356	$ 310,333,678	$ 310,333,678

Note:
Subfunctionalization of accounts 360-367 into primary/secondary is based on BPU Staff's methodology.

Jersey Central Power & Light

WP-6 BPU Staff Voltage Specific Load Factor Calculations

	Net System Requirements (MWh)	CP	Load Factor (Energy Cost)	1 minus Load Factor (Demand Cost)	Customer Alloc
Total Company	22,206,312	5,198	48.8%	51.2%	0.0%
GT & GT-D	2,112,426	295	81.8%	18.2%	
Distribution Primary	20,093,885	4,903	46.8%	53.2%	0.0%
Rate GP	1,812,153	287	72.1%	27.9%	
Distribution Secondary	18,281,733	4,616	45.2%	54.8%	0.0%

Avg/Exc Allocator for Sch GT & GT-D A&G Exp	Net System Requirements	CP	Load Factor (Energy Alloc)	1-minus LF (Demand Alloc)	GT & GT-D Class Direct Alloc	Adjusted Energy Alloc	Adjusted Demand Alloc
Dist - Primary	20,093,885	4,903	46.8%	53.2%	0.275%	46.7%	53.1%

Calculation of GT & GT-D Class Direct Allocation

Total Distribution PIS	$5,063,247,618
GT & GT-D Class Allocated PIS	$13,916,259
GT & GT-D Class Direct Allocation	0.275%

Jersey Central Power & Light
WP-7 Non-Consumption Revenue Allocators
July 2019 - June 2020 (2019-2020 6+6)

Rate Class	Account 450 (Late Payment)	Account 451 (Non-consumption service fees)
RS	$ 347	$ 4,256,421
RT	$ -	$ 40,846
GS	$ 1,833,682	$ 687,062
GST	$ 65,385	$ 54,613
GP	$ 234,858	$ 15,742
GT	[redacted]	
GT-D		
Lighting	$ 293,510	$ 62,234
TOTAL	**$ 2,247,882**	**$ 5,157,790**

Jersey Central Power & Light
WP-8 Total Supervision, Meter Reading, and Miscellaneous Customer Account Expense

Total Supervision and Miscellaneous Customer Account Expense Assigned by Rate Class				
Rate Class	Customer Count	Weighting Factor[1]	Weighted Customers	Allocation Factor
RS	986,002	1.00	986,002	79.3%
RT	15,213	1.30	19,777	1.6%
GS	125,569	1.81	227,280	18.3%
GST	197	15.62	3,077	0.2%
GP	423	4.38	1,853	0.1%
GT	[redacted]			
GT-D				
Lighting	2,938	1.11	3,249	0.3%
Total	1,130,505		1,242,727	100.0%

(1) Based on Weighted Factor from 2002 JCP&L Study

Jersey Central Power & Light
WP-9 BPU Staff's Meter Cost Allocation Method

		A	B	C	D	E	F	G	H	I	J	K
Line	**Rate Class**	**Total Value Meter**	**Total Value of Transformers**	**Total Meter & Transformers**	**Percentage of FERC Account Value Allocated to Rate Class**	**Account 370 Meter Cost**	**Allocated Customer Component**	**Allocated Demand Component**	**Meter Count**	**Minimum Meter MAP Value**	**Total Meter-Cust Component**	**Percent Cust Component**
1	RS	$ 24,627,791	$ 210,954	$ 24,838,745	58.6%	$ 105,691,531	76,227,441	$ 29,464,090	1,004,167	$ 17.84	$ 17,914,339	72.12%
2	RT	1,310,395	9,810	1,320,206	3.1%	5,617,617	1,148,308	4,469,309	15,127	$ 17.84	269,866	20.44%
3	GS	7,597,577	3,976,359	11,573,935	27.3%	49,248,340	9,647,316	39,601,024	127,087	$ 17.84	2,267,232	19.59%
4	GST	92,995	360,319	453,314	1.1%	1,928,898	68,874	1,860,024	202	$ 80.13	16,186	3.57%
5	GP	229,756	1,607,383	1,837,138	4.3%	7,817,222	7,817,222	-				100%
6	GT	[redacted]										
7	GT-D											
8	Total	$ 33,989,406	$ 8,374,796	42,364,202	100%	$ 180,264,239	104,869,792	75,394,447				

NOTES

FERC Account 370 Allocation Method is based on Staff's Methodology as ordered to use by the BPU in Case no. ER12111052

Column A = Total Value of Meters from Company system
Column B = Total Value of Transformers, from Company system
Column C = Calculation: Column A + Column B
Column D = Calculation: Column C, per rate class / Column C, Line 8
Column E = Lines 1 through 7 Calculation: Column D, per rate class * Column E, Line 8. Line 8 FERC Account 370 Value
Column F = Calculation: Column E * Column K
Column G = Calculation: Column E - Column F
Column H = Meter Count from Company system
Column I = Minimum Moving Average Price for Meters by rate class
Column J = Calculation: Column H * Column I
Column K = Calculation Column J / Column C

Jersey Central Power & Light
WP-10 Labor as a Percentage of Total Unadjusted O&M Expense
July 2019 - June 2020 (2019-2020 6+6)

Total O&M Expenses	$230,746,400
O&M Labor Expense	$81,541,550
Labor Exp as Percent of O&M	35.3%

Jersey Central Power & Light
WP-11 PowerGuard Revenues
July 2019 - June 2020 (2019-2020 6+6)

Rate Class	Account 456 (Powerguard)
RS	$ 251,400
RT	$ 11,170
GS	$ 11,650
GST	$ -
GP	$ -
GT	[redacted]
GT-D	
Lighting	$ -
TOTAL	**$ 274,221**

Jersey Central Power & Light
WP-12 Average Monthly Non-Coincident Peak Demands (NCD)
June - September 2019

Non-Coincident Peak Demands	
Rate Class	NCD (MWs)
RS	3,212,553
RT	50,440
GS	1,774,266
GST	118,899
GP	334,543
GT	[redacted]
GT-D	
Lighting	42,773
Total	5,950,481

REDACTED

Jersey Central Power & Light
WP-13 Company Proposed Voltage Specific Load Factor Calculations

Avg/Exc Allocator	Net System Requirements	NCD	Energy Alloc (Load Factor)	Demand Alloc (1 -Load Factor)	Customer Alloc
Total Company	22,206,312	5,950	42.6%	57.4%	0%
	Gradually move 1/2 to Demand		21.3%	78.7%	0%
Rate GT & GT-D	2 112 426	417	57.8%	42.2%	
Dist - Primary	20,093,885	5,533	41.5%	58.5%	0%
	Gradually move 1/2 to Demand		20.7%	79.3%	0%
Rate GP	1,812,153	335	61.8%	38.2%	
Dist - Secondary	18,281,733	5,199	40.1%	59.9%	0%
	Gradually move 1/2 to Demand		20.1%	79.9%	0%

Avg/Exc Allocator for Sch GT & GT-D A&G Exp	Net System Requirements	NCD	Load Factor (Energy Alloc)	1-minus LF (Demand Alloc)	GT & GT-D Class Direct Alloc	Adjusted Energy Alloc	Adjusted Demand Alloc
Dist - Primary	20,093,885	5,533	41.5%	58.5%			
	Gradually move 1/2 to Demand		20.7%	79.3%	0.197%	20.7%	79.1%

Calculation of GT & GT-D Class Direct Allocation

Total Distribution PIS	$5,063,247,618
GT & GT-D Class Allocated PIS	$9,960,631
GT & GT-D Class Direct Allocation	0.197%

Jersey Central Power & Light
WP-14 Company Proposed Primary/Secondary Segmentation

FERC Account	Primary %	Secondary %
360	41.1%	58.9%
361	63.3%	36.7%
362	100.0%	0.0%
364	30.5%	69.5%
365	30.5%	69.5%
366	30.5%	69.5%
367	30.5%	69.5%

Original Investment	Total $	Primary $	Secondary $
360	$ 32,657,627	$ 13,422,285	$ 19,235,342
361	$ 59,700,110	$ 37,790,169	$ 21,909,940
362	$ 527,855,471	$ 527,855,471	$ -
364	$ 753,081,665	$ 229,359,247	$ 523,722,418
365	$ 1,183,852,378	$ 360,555,173	$ 823,297,205
366	$ 117,207,235	$ 35,696,744	$ 81,510,491
367	$ 620,667,356	$ 189,031,023	$ 431,636,333

Note:
Subfunctionalization of accounts 364-367 into primary/secondary is based on a 2016 internal engineering study

Jersey Central Power & Light
WP-15 Company's Meter Cost Allocation Method

		A	B	C	D	E	F	G	H	I	J
Line	Rate Class	Total Value Meter	Total Value of Transformers	Total Meter & Transformers	Meter Cost Allocation by Rate Class	Account 370 Meter Cost	Min Installed Cost	Wtd Avg Installed Cost	Customer Component %	Allocated Customer Component	Allocated Demand Component
1	RS	$ 24,627,791	$ 210,954	$ 24,838,745	58.6%	$ 105,691,531	$242.15	$252.33	96%	101,425,716	$ 4,265,815
2	RT	1,310,395	9,810	1,320,206	3.1%	5,617,617	$242.15	$360.36	67%	3,774,843	1,842,773
3	GS	7,597,577	3,976,359	11,573,935	27.3%	49,248,340	$242.15	$520.73	47%	22,901,299	26,347,041
4	GST	92,995	360,319	453,314	1.1%	1,928,898	$1,473.95	$4,465.86	33%	636,628	1,292,271
5	GP	229,756	1,607,383	1,837,138	4.3%	7,817,222			100%	7,817,222	-
6	GT	[redacted]									
7	GT-D										
8	Total	$ 33,989,406	$8,374,796	$42,364,202	100.0%	$180,264,239				146,516,339	$ 33,747,900
									CF =	81.3%	18.7%

NOTES:
Column A = Total Value of Meters, from company system
Column B = Total Value of Transformers, from Company system
Column C = Calculation: Column A + Column B
Column D = Calculation: Column C, per rate class /Column C, Line 8
Column E = Lines 1 through 7 Calculation: Column D, per rate class * Column E, Line 8. Line 8 FERC Account 370 Value
Column F = Minimum Installed Meter Cost for secondary voltage rate classes
Column G = Weighted average meter installed costs for secondary voltage rate classes
Column H = Column F / Column G
Column I = Column E * Column H
Column J = Column E - Column I

Jersey Central Power & Light
WP-16 Average Number of Customers Served by Circuit Type

	Average Number of Primary Metered Customers on Circuit	Average Total Number of Customers on Circuit
Circuits with Primary and Secondary Customers	1.4	989
Circuits with Secondary Metered Customers Only	0	983

Jersey Central Power & Light

WP-17 Primary/Secondary Segmentation for Accounts 580, 589 & 590

Proposed Segmentation of Accounts 580, 589 & 590			
Plant Account	Primary	Secondary	Total
360	$13,422,285	$19,235,342	$32,657,627
361	$37,790,169	$21,909,940	$59,700,110
362	$527,855,471	$0	$527,855,471
364	$229,359,247	$523,722,418	$753,081,665
365	$360,555,173	$823,297,205	$1,183,852,378
366	$35,696,744	$81,510,491	$117,207,235
367	$189,031,023	$431,636,333	$620,667,356
368	$0	$853,891,746	$853,891,746
369	$0	$469,594,395	$469,594,395
Total	$1,393,710,112	$3,224,797,870	$4,618,507,982
	30.2%	69.8%	

Complied Segmentation of Accounts 580, 589 & 590			
Plant Account	Primary	Secondary	Total
360	$16,328,813	$16,328,813	$32,657,627
361	$29,850,055	$29,850,055	$59,700,110
362	$263,927,736	$263,927,736	$527,855,471
364	$376,540,833	$376,540,833	$753,081,665
365	$591,926,189	$591,926,189	$1,183,852,378
366	$105,486,511	$11,720,723	$117,207,235
367	$310,333,678	$310,333,678	$620,667,356
368	$0	$853,891,746	$853,891,746
369	$0	$469,594,395	$469,594,395
Total	$1,694,393,815	$2,924,114,167	$4,618,507,982
	36.7%	63.3%	

Jersey Central Power & Light
WP-18 Company Proposed Service Cost Allocation Method

		A	B	C	D	E	F	G	H
Line	**Rate Class**	**Total Service Cost**	**Cost Allocation by Rate Class**	**Account 369**	**Min Installed Cost**	**Wtd Avg Installed Cost**	**Customer Component %**	**Allocated Customer Component**	**Allocated Demand Component**
1	RS	$50,071,700	75.83%	$356,073,297	$576.78	$577.05	100.0%	$355,908,356	$164,940
2	RT	$750,958	1.14%	$5,340,261	$576.78	$576.90	100.0%	$5,339,140	$1,121
3	GS	$15,155,186	22.95%	$107,772,597	$576.78	$754.10	76.5%	$82,430,952	$25,341,645
4	GST	$57,408	0.09%	$408,240	$939.99	$1,059.81	88.7%	$362,086	$46,154
5	Total	$66,035,251	100%	$469,594,395				$444,040,534	$25,553,860

NOTES:
Column A = Direct Material Cost for services for secondary rate classes
Column B = Calculation: Column A, per rate schedule /Column A, Line 5
Column C = Lines 1 through 4 Calculation: Column B, per rate schedule * Column C, Line 5. Line 5 = FERC Account 369 balance
Column D = Minimum Installed Service Cost for secondary voltage rate classes
Column E = Weighted Average Service Installed Costs for secondary voltage rate classes
Column F = Column D / Column E
Column G = Column C * Column F
Column H = Column C - Column G

FirstEnergy

Distribution System Planning Criteria

August 2014

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

EXHIBIT JC-12

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Yongmei Peng

Re: Tariff Revisions and Design of the Proposed Distribution Rates

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Yongmei Peng and my business address is 300 Madison Avenue, Morristown, NJ 07962.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as an Analyst V – Rates & Regulatory Affairs, New Jersey. My professional and educational background is provided in Appendix A to my testimony.

In my current position, I am responsible for developing the design of retail rates for Jersey Central Power & Light Company ("JCP&L" or the "Company"). I also am responsible for managing the recovery of basic generation service and transmission costs. In my position, I provide analytical support for all regulatory filings and for the implementation of all rate changes to the JCP&L Tariff for Service (the "Tariff"). JCP&L is an operating company subsidiary of FirstEnergy Corp., and an affiliate of FirstEnergy Service Company.

Q. Have you previously testified in proceedings before the New Jersey Board of Public Utilities ("Board" or "BPU")?

A. Yes. I have previously provided written testimony that was filed with the Board. More specifically, I was the witness on the subject of Proof of Revenues and Customer Impacts in *I/M/O the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Services, and for Approval of Other Proposed Tariff*

Revisions in Connection Therewith ("2016 Base Rate Filing") at BPU Docket No. ER16041383, which was settled prior to hearings.

Q. Please describe the purpose of your direct testimony.

A. The purpose of my testimony is to:

(i) Discuss the Company's proposed distribution rate design;

(ii) Provide the proof of revenues supporting the results of the Company's rate design process;

(iii) Demonstrate that the total requested revenue requirement from the Company's Cost of Service Study ("COSS") is properly accounted for;

(iv) Analyze customer impacts associated with the Company's proposed distribution rate changes in this proceeding; and

(v) Present modifications to the current Tariff, as set forth in my testimony and the testimony of other JCP&L witnesses.

Q. Can you please briefly summarize your testimony?

A. Yes. My testimony begins by discussing the design of the Company's distribution rates. As detailed herein, while JCP&L is proposing changes to some of its rates, it is not proposing changes to its fundamental rate structure or the process it uses to develop rates. Next, I discuss JCP&L's proposal to increase the customer charge component of its rates for certain rate schedules, based upon and as justified by the COSS. After that, I provide the proof of revenues analysis and discuss the cost of service revenue requirements as shown by the COSS. Then, I provide the estimated customer impacts resulting from the Company's proposed rate increase. Finally, I provide the current and proposed tariff sheets for JCP&L and mention the Tariff changes being requested by the Company, as detailed in the testimony of other Company witnesses.

Q. **Please describe the attachments to your testimony.**

A. The following schedules are attached to my testimony:

(i) Schedule YP-1 provides a summary of changes in the distribution revenue requirement and shows the classified revenue requirement by rate class derived from the Company's proposed COSS, which is included in the direct testimony of Stephanie R. Zieger (Exhibit JC-11).

(ii) Schedule YP-2 provides a summary proof comparing JCP&L's cost of service distribution revenue requirements to the Company's proposed distribution revenues.

(iii) Schedule YP-3 contains JCP&L's proof of revenues for all Company distribution Tariff rate components by Tariff rate class.

(iv) Schedule YP-4 provides the Company's customer impact analysis by Tariff rate class.

(v) Schedule YP-5 contains the current and proposed tariffs.

II. DESIGN OF THE COMPANY'S PROPOSED DISTRIBUTION RATES

Q. **Please describe the fundamental goal applied in designing the proposed distribution rates in this proceeding**

A. Cost causation is the overriding principle that guides the rate design; specifically, rate structure should reflect the underlying cost structure, and rates must be at a level sufficient to permit the Company to recover its revenue requirement. Electricity rates should also reflect the costs of service in order to appropriately convey the underlying costs to customers in an understandable manner that ensures the efficient use of resources and promotes greater customer satisfaction.

Q. **Please explain the general process of JCP&L's rate design.**

A. Four ratemaking steps are incorporated in designing JCP&L's rates:

1. <u>Revenue Requirement</u> – First, the revenue requirement is developed based on Company operating expenses, taxes, depreciation expense and return on rate base. In her direct testimony (Exhibit JC-4), Carol A. Pittavino presents the distribution system revenue requirement for JCP&L based on a test year from July 2019 to June 2020;
2. <u>Cost of Service Study ("COSS")</u> – In this step, as detailed in Ms. Zieger's testimony (Exhibit JC-11), JCP&L's distribution revenue requirement is allocated to various rate classes based on cost causation principles;
3. <u>Interclass Revenue Moderation</u> – Next, the impacts some rate classes would experience if rates were designed to collect their entire COSS-allocated revenue requirement are reviewed and considered for moderation consistent with the principles of gradualism; and
4. <u>Intraclass Rate Design</u> – The final step establishes the individual rates that are ultimately used to bill customers. Such rates are designed to collect the revenue requirement, as moderated, from customers on a class-by-class basis.

Q. **What do you mean by interclass revenue requirement moderation?**

A. The primary objective of this step is to moderate the impact that would result from matching allocation of costs among rate classes based solely on the costs caused by each rate class, as determined by the COSS. This is accomplished through adjustments that balance the application of cost causation principles against other concerns and interests important to sound rate design, including reducing significant rate class cross-subsidies and preventing undue customer impact.

Q. Please explain how interclass revenue requirement moderation is implemented.

A. First, the COSS presents the unitized rates of return ("UROR") for each rate class. The UROR of a rate class is the class rate of return divided by the Company's overall average rate of return.

A class UROR greater than 1.0 indicates that the rate class revenue requirement exceeds its cost of service. A class UROR less than 1.0 indicates that the rate class revenue requirement is less than its cost of service. URORs are used as a guide to measure the progress proposed changes in rates will achieve in moving all rate classes toward a UROR of 1.0 or "unity," which is generally accepted as a desirable goal in rate design.

It is also generally recognized, however, that a very rapid movement toward unity can produce undesirable customer rate impacts. The Board has long held that progress toward unity should be tempered with gradualism in order to mitigate the impact of rate changes on customers.

Q. What is gradualism?

A. Gradualism is a precept of utility ratemaking that refers to the process of moving to unity over time (i.e., over the course of multiple base rate cases). Gradualism is a consistent consideration in establishing rates for all rate classes. If the movement toward unity would result in subjecting one or more rate classes to an unreasonable customer impact in a particular base rate case, then the principle of gradualism would call for subordinating the goal of achieving unity to the goal of moderating customer impact even though doing so would cause some classes to generate revenues in excess of their particular COSS-determined class revenue requirement. Where gradualism is an appropriate consideration for a particular rate class, the movement toward unity for that rate class may be done incrementally and spread over time to reduce the risk of rate shock.

Q. What do you mean by intraclass rate design?

A. The COSS provides classified costs (e.g. customer-related or demand-related) and allocates them to each rate class, which facilitates the development of a series of specific corresponding individual rate elements (i.e., customer, demand and energy charges). However, consideration of customer impact, revenue stability, ease of application and understanding, as well as other practical concerns may temper the extent to which these individual rate elements are used to reflect the respective costs of service for each cost classification. For example, there are no demand charges for customer classes that do not have demand metering and, therefore, for those customers, both demand and energy costs are recovered with a per-kWh charge.

Once the amount of classified revenue each rate element should produce has been determined, charges for each rate element must be established based on the applicable billing determinants so that the rates will produce the target level of revenue.

My general approach to the intraclass rate design step is guided by the following principles:

(i) Individual rates should reflect the associated unit cost of service, so that proposed revenues, derived with rates applied with billing determinants, should move towards full cost basis, as provided by the COSS;

(ii) The rates by class should increase on a percentage basis to meet the Company's overall rate increase in a measured way with equitable recovery from amongst other classes for any shortfall within each rate class;

(iii) The proposed change in individual rates should ensure reasonable customer impacts.

Q. Please explain the results of the COSS in this filing as it relates to interclass rate design.

A. As mentioned above, the COSS is explained and discussed in the direct testimony of Ms. Zieger (Exhibit JC-11).

Schedule YP-1 shows the summary of distribution revenue requirement changes and classified revenue requirements by rate class that has been excerpted from the COSS.

As indicated in Schedule YP-1, the overall proposed increase on the base distribution revenue requirement is $186.9 million.

While no class will get a decrease, RS, RT and GST will increase between 95% and 105% of the Company's overall distribution increase. The GS class will increase by approximately the same percentage of the Company's overall distribution increase. The GP and GT classes, with significantly higher URORs than 1, will increase by 90% of the Company's overall distribution increase. The Lighting class will increase 50% of the Company's overall distribution increase.

The proposed revenue requirement changes move all rate classes, except Lighting, closer to an UROR of 1, while balancing the overall customer impact as provided in Schedule YP-4.

Q. Please describe the rate structure resulting from the rate design used to establish the rates set forth in the current tariff.

A. The rates set forth in the Company's current tariff (Part III) were approved by the BPU in the Company's 2016 Base Rate Filing proceeding and reflect the Board's decisions regarding rate structure and rate design made in that case. While the Company proposes changes to various rates, the changes reflected in the Company's proposed rates do not change the underlying rate structure and principles applied in rate design, as approved in the 2016 Base Rate Filing.

Consistent with the changes in class revenue requirements set forth in Schedule YP-1, the Company is proposing to increase the rates for each Service Classification as follows:

Residential Customers: For customers served under Service Classifications RS (Residential Service), RT (Residential Time-of-Day Service) and RGT (Residential Geothermal & Heat Pump Service), the Company is proposing to increase the monthly customer charges, and the monthly supplemental charges for water heating, in order to fully recover the classified customer revenue requirement from COSS. This results in an increase in the RS customer charge of $1.33, resulting in a customer charge of $4.11, including sales and use tax ("SUT").

The proposed distribution charges, which are expressed on a per-kWh basis, were calculated by increasing the current charges by an equal percentage, such that the sum of the revenue that would be produced by such proposed distribution charges and the revenue that would be produced by the proposed customer charges equals the target revenue for each service classification.

Commercial and Industrial Customers. For customers served under Service Classifications GS (General Service Secondary), Service Classifications GST (General Service Secondary Time-of-Day), Service Classifications GP (General Service Primary) and GT (General Service Transmission), the Company proposes to increase the customer charge and demand charge, which is expressed on per kW basis, toward fully recovering their respective classified revenue requirement from the COSS, but no more than the class level increase or the Company's overall revenue increase. The distribution charge, which is expressed on a per kWh basis, would be increased at a certain percentage so that the sum of the resulting distribution revenue, demand revenue and customer charges proposed would equal the target class level revenue requirement. To avoid unreasonable customer impacts resulting from the gradual movement of distribution charges into the customer and demand charge, it is necessary to temper the customer and demand charge increases as follows:

For Service Classification GS (General Service Secondary), the customer charge will be increased toward the full recovery of classified customer revenue from the COSS. The Demand charge will be increased to no more than 15% above the class level increase. For Service Classification GST (General Service Secondary – Time of Day), both the customer and demand charge are proposed to increase by no more than 10% above the class level increase.

For Service Classifications GP (General Service Primary) and GT (General Service Transmission), both customer charges and demand charges are increased by no more than the Company's total percent increase in distribution revenue.

Lighting Customers. For customers served under Service Classifications OL (Outdoor Lighting Service), SVL (Sodium Vapor Street Lighting Service), MVL (Mercury Vapor Street Lighting – Restricted) and ISL (Incandescent Street Lighting – Restricted), all distribution charges (including fixture, miscellaneous and kWh charges) under current rates are proposed for increase by an equal percentage to produce the target level of revenues for these Tariff service classifications. For Service Classification LED (LED Street Lighting Service), JCP&L proposes to offer an additional Company Fixture option and new Contribution Fixtures options, as described in the direct testimony of Mark A. Mader (Exhibit JC-3), and proposes to increase current fixture charges by a lower percentage, reflecting the reduced cost of serving existing Company fixtures.

Q. **Is the Company proposing any additional interclass and intraclass rate design adjustments?**

A. The company does not plan to propose additional adjustments. However, the Company recognizes that, over the course of any rate proceeding, other parties may propose adjustments to the interclass or intraclass determinations and proposals originally made by the Company. Any such proposals would necessarily impact other aspects of the rate structure resulting from the rate design, or the rate design itself. Therefore, the Company reserves the right to respond to any such proposed modifications in order to identify other changes that might be required to accommodate any such proposals.

Q. **Did you perform a proof of revenues analysis?**

A. Yes, I did.

Schedule YP-2 demonstrates, in summary form, the accounting for the total requested revenue requirement based upon the COSS.

Schedule YP-3 sets forth: (1) the normalized billing determinants in the test year used to develop all proposed distribution rates; (2) the test year revenue based on present rates; (3) the test year revenue based on proposed rates; and (4) the percentage increase resulting from the proposed rates.

Q. Please discuss the customer impact of the proposed changes in distribution rates.

A. The results are contained in Schedule YP-4.

In performing this analysis, the first step was to identify all rate components that would be included in all customers' bills, as of February 1, 2020. The rate components include: distribution charges (including customer charges), societal benefits charges, non-utility generation charges, the RGGI recovery charge, the Zero Emission Certificate Recovery Charge and the Tax Act Adjustment as set forth in the current Tariff. Additionally, customers that do not select an alternate generation supplier will have Basic Generation Service ("BGS") charges (including transmission charges) as a component on their bills.

The customer impact analysis model incorporates all rate components by Tariff rate class. In performing the customer impact analysis, total revenues billed for the twelve months prior to February 1, 2020 were compared to the total revenues that would be produced by the distribution Tariff rates proposed in this proceeding, yielding the results of the proposed changes in both total revenue dollars and in percentages by Tariff rate class.

Because the sales and use tax ("SUT") is included in customer bills, the customer impact analysis also includes SUT in order to show the results from the customers' perspective.

III. PROPOSED TARIFF CHANGES

Q. What are the Company's proposed changes to its current tariff?

A. The Company is proposing modifications to Part I (General Information) and Part II (Standard Terms and Conditions) of its proposed tariff BPU No. 13 – Electric when it is filed at the conclusion of this proceeding. In addition, Part III (Service Classifications and Riders) of the proposed tariff will incorporate all proposed distribution rate changes from this proceeding.

Schedule YP-5 contains the current Tariff and the proposed tariff. For convenience, Parts I, II and III of the current Tariff are being provided in their entirety. Part I, II and III of the proposed tariff incorporate all of the Company's proposed changes, and the tariff sheets have been renumbered to conform to the way they will appear in the next tariff for Service if the Company's proposals in this proceeding are approved by the Board.

Q. Please describe the tariff changes that are proposed for Parts I, II and III of the current Tariff?

Please refer to the direct testimony of Thomas R. Donadio (Exhibit JC-13) whose testimony, among other things, discusses some of the details relating to the proposed changes in Parts I and II of the Tariff.

Please refer to the direct testimony of Dennis M. Pavagadhi (Exhibit JC-7) whose testimony, among other things, discusses the details of the proposed changes to Appendix A in Part II of the Tariff.

Please refer to the direct testimony of Mark A. Mader (Exhibit JC-3) whose testimony, among other things, discusses the change in Part III to Service classification LED (LED Street Lighting Service) ("LED").

Q. Does this conclude your direct testimony?

A. Yes, it does.

Appendix A

Yongmei Peng

PROFESSIONAL AND EDUCATIONAL BACKGROUND

Yongmei Peng is employed by FirstEnergy Service Company as a Tariff Activity Analyst in the New Jersey Rates & Regulatory Affairs Department. She is responsible for: (1) all analysis and design of JCP&L's retail rates related to the recovery of costs for basic generation service and transmission, (2) customer impact analysis for all regulatory petitions, (3) Tariff changes, updates and associated compliance filings with the Board, and (4) rates implementation, interpretation and application for JCP&L. She has held this position since May 2005. JCP&L is an operating company subsidiary of FirstEnergy Corp.

Prior to taking her current position, Ms. Peng was employed by JCP&L from May 1995 through April 2005 as a Business Analyst in the Company's Energy Efficiency Group working on New Jersey Clean Energy Programs from 1997 through April 2005, and, prior to 1997 on Demand Side Management ("DSM") Programs. Her responsibilities included maintaining various measurement and meter information databases, implementing the statewide Measurement and Verification Protocol and evaluating energy and revenue impacts of all conservation programs.

From September 1993 through April 1995, Ms. Peng was employed by Honeywell DMC Services, LLC to work for JCP&L as a database administrator of JCP&L's proprietary commercial and industrial DSM program tracking system. She was also accountable for all measurement data tracking and reporting for the residential DSM programs.

Ms. Peng graduated from Stevens Institute of Technology in 1993 with a Master of Science degree in Management Information Systems.

Exhibit JC-12
Schedule YP - 1

Jersey Central Power & Light Company
Summary of Distribution Revenue Requirement Changes and Classified Revenue Requirements
Excerpted from Cost of Service Study, Exhibit JC-11, Schedule SRZ-2

	TOTAL	RS	RT	GS	GST	GP	GT	LTG
RATE CHANGE REQUESTED								
REVENUE CHANGE	**$186,945,938**	**$102,458,038**	**$2,080,000**	**$61,580,000**	**$4,040,000**	**$7,850,000**	**$5,877,900**	**$3,060,000**
% REVENUE INCREASE / (DECREASE)	34.4%	36.1%	32.7%	34.3%	36.3%	30.9%	30.9%	17.2%
REQUESTED RATE OF RETURN	7.76%	6.74%	8.76%	8.62%	7.73%	15.97%	45.28%	3.19%
PROPOSED UNITIZED RATE OF RETURN	1.00	0.87	1.13	1.11	1.00	2.06	5.84	0.41
CUSTOMER								
DISTRIBUTION TARIFF REVENUE	**$70,867,851**	**$45,731,114**	**$1,483,832**	**$12,802,996**	**$228,582**	**$3,112,181**	**$7,509,145**	**$0**
DEMAND								
DISTRIBUTION TARIFF REVENUE	**$538,239,390**	**$283,354,233**	**$5,512,181**	**$183,333,149**	**$11,511,236**	**$21,584,469**	**$12,637,468**	**$20,306,655**
ENERGY								
DISTRIBUTION TARIFF REVENUE	**$120,707,465**	**$56,949,396**	**$1,453,021**	**$45,014,449**	**$3,423,629**	**$8,537,628**	**$4,742,685**	**$586,657**
TOTAL								
DISTRIBUTION TARIFF REVENUE	**$729,814,706**	**$386,034,743**	**$8,449,034**	**$241,150,595**	**$15,163,447**	**$33,234,277**	**$24,889,298**	**$20,893,311**

Exhibit JC-12
Schedule YP - 2

Jersey Central Power & Light Company
Summary
Proof of Cost of Service Distribution Tariff Revenue to Proposed Distribution Rates

Rate Class		COSS Distribution Tariff Revenue (1) (a)	Proposed Distribution Revenue Charges: Customer (b)	kWh Dist. (c)	Demand (d)	Total (f)=(b)+(c)+(d)+(e)	Revenue Delta (g)=(f)-(a)	Per kWh Delta
RS	Distribution							
	Customer	$45,731,114	$45,699,995	$29,730	$0	$45,729,725		
	Demand	$283,354,233	$0	$283,354,233	$0	$283,354,233		
	Energy	$56,949,396	$0	$56,949,396	$0	$56,949,396		
	Total	$386,034,743	$45,699,995	$340,333,359	$0	$386,033,354	-$1,389	-0.0000002
RT & RGT	Distribution							
	Customer	$1,483,832	$1,484,307	-$455	$0	$1,483,852		
	Demand	$5,512,181	$0	$5,512,181	$0	$5,512,181		
	Energy	$1,453,021	$0	$1,453,021	$0	$1,453,021		
	Total	$8,449,034	$1,484,307	$6,964,747	$0	$8,449,054	$20	0.0000001
GS	Distribution							
	Customer	$12,802,996	$12,804,377	-$1,381	$0	$12,802,996		
	Demand	$183,333,149	$0	$50,522,976	$132,810,173	$183,333,149		
	Energy	$45,014,449	$0	$45,016,219	$0	$45,016,219		
	Total	$241,150,595	$12,804,377	$95,537,814	$132,810,173	$241,152,364	$1,769	0.0000003
GST	Distribution							
	Customer	$228,582	$131,990	$96,592	$0	$228,582		
	Demand	$11,511,236	$0	-$703,304	$12,214,540	$11,511,236		
	Energy	$3,423,629	$0	$3,423,553	$0	$3,423,553		
	Total	$15,163,447	$131,990	$2,816,841	$12,214,540	$15,163,371	-$76	-0.0000001
GP	Distribution							
	Customer	$3,112,181	$336,399	$2,775,782	$0	$3,112,181		
	Demand	$21,584,469	$0	-$4,875,465	$26,459,934	$21,584,469		
	Energy	$8,537,628	$0	$8,538,060	$0	$8,538,060		
	Total	$33,234,277	$336,399	$6,438,376	$26,459,934	$33,234,709	$432	0.0000002
GT	Distribution							
	Customer	$7,509,145	$558,685	$6,950,460	$0	$7,509,145		
	Demand	$12,637,468	$0	-$6,888,374	$19,525,842	$12,637,468		
	Energy	$4,742,685	$0	$4,742,292	$0	$4,742,292		
	Total	$24,889,298	$558,685	$4,804,378	$19,525,842	$24,888,905	-$393	-0.0000002
Lighting	Distribution		Fixtures	Misc.	kWh			
	Total	$20,893,311	$14,603,280	$432,393	$5,857,693	$20,893,366	$55	0.0000005
Total	Customer	$70,867,851	$61,015,753	$9,850,727	$0	$70,866,480		
	Demand	$517,932,735	$0	$326,922,246	$191,010,489	$517,932,735		
	Energy	$120,120,808	$0	$120,122,541	$0	$120,122,541		
	Lighting Total	$20,893,311	$14,603,280	$432,393	$5,857,693	$20,893,366		
	Total	$729,814,706	$75,619,033	$457,327,908	$196,868,182	$729,815,123	$419	0.0000000

(1) Source: Exhibit JC-11, Schedule SRZ - 2

Jersey Central Power & Light Company

Summary Proof of Revenues

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

	Revenue at Proposed Rates Effective TBD								
Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	TAA	BGS	Total
RS	$680,198	$386,033,354	$110,763,497	$59,648,859	$36,277,244	$0	-$2,639,170	$667,482,969	$1,258,246,951
RT/RGT	$15,863	$8,449,054	$2,583,163	$1,391,097	$846,037	$0	-$60,915	$16,555,291	$29,779,590
GS	$711,527	$241,152,364	$81,213,760	$43,735,601	$26,599,119	$0	-$1,708,993	$501,360,813	$893,064,191
GST	$56,595	$15,163,371	$6,459,897	$3,478,813	$2,115,745	$0	-$105,787	$33,030,901	$60,199,535
GP	$176,542	$33,234,709	$13,806,630	$11,383,503	$6,923,219	$0	-$249,236	$92,683,900	$157,959,267
GT	$184,667	$24,888,905	$12,440,573	$13,608,394	$8,276,354	$0	-$180,011	$102,944,055	$162,162,937
Lighting	$12,379	$20,893,366	$0	$760,853	$462,736	$0	-$170,055	$6,139,921	$28,099,200
Total	$1,837,771	$729,815,123	$227,267,520	$134,007,120	$81,500,454	$0	-$5,114,167	$1,420,197,850	$2,589,511,671

	Change in Revenue from Current Rates to Proposed Rates Effective TBD								
Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	TAA	BGS	Total
RS	$0	$102,456,649	$0	$0	$0	$0	$0	$0	$102,456,649
RT/RGT	$0	$2,080,020	$0	$0	$0	$0	$0	$0	$2,080,020
GS	$0	$61,581,769	$0	$0	$0	$0	$0	$0	$61,581,769
GST	$0	$4,039,924	$0	$0	$0	$0	$0	$0	$4,039,924
GP	$0	$7,850,432	$0	$0	$0	$0	$0	$0	$7,850,432
GT	$0	$5,877,508	$0	$0	$0	$0	$0	$0	$5,877,508
Lighting	$0	$3,060,055	$0	$0	$0	$0	$0	$0	$3,060,055
Total	$0	$186,946,357	$0	$0	$0	$0	$0	$0	$186,946,357

	Percentage Change in Revenue from Current Rates to Proposed Rates Effective TBD								
Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	SRC	BGS	Total
RS	0.0%	8.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.9%
RT/RGT	0.0%	7.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.5%
GS	0.0%	7.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.4%
GST	0.0%	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.2%
GP	0.0%	5.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.2%
GT	0.0%	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%
Lighting	0.0%	12.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.2%
Total	0.0%	7.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.8%

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Residential Service (RS)

Description of Charge	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Standard Customer Charge	11,832,020	$2.61	$30,881,573	1 Standard Customer Charge	11,832,020	$3.85	$45,553,278	$14,671,705	47.5%
2 Supplemental OPWH {3}	31,452	$1.36	$42,775	2 Supplemental OPWH {3}	31,452	$2.01	$63,219	$20,444	47.8%
3 Supplemental CTWH {3}	41,541	$1.36	$56,496	3 Supplemental CTWH {3}	41,541	$2.01	$83,498	$27,002	47.8%
4 Total Customer Charges	11,832,020		$30,980,844	4 Total Customer Charges	11,832,020		$45,699,995	$14,719,151	47.5%
NGC per kWh Charges				NGC per kWh Charges					
5 Summer kWh 0 - 600	1,984,067,702	$0.000075	$148,805	5 Summer kWh 0 - 600	1,984,067,702	$0.000075	$148,805	$0	0.0%
6 Summer kWh > 600	1,830,221,042	$0.000075	$137,267	6 Summer kWh > 600	1,830,221,042	$0.000075	$137,267	$0	0.0%
7 Winter All kWh	5,246,685,370	$0.000075	$393,501	7 Winter All kWh	5,246,685,370	$0.000075	$393,501	$0	0.0%
8 Summer OPWH kWh	955,675	$0.000075	$72	8 Summer OPWH kWh	955,675	$0.000075	$72	$0	0.0%
9 Winter OPWH kWh	2,388,854	$0.000075	$179	9 Winter OPWH kWh	2,388,854	$0.000075	$179	$0	0.0%
10 Summer CTWH kWh	1,337,655	$0.000075	$100	10 Summer CTWH kWh	1,337,655	$0.000075	$100	$0	0.0%
11 Winter CTWH kWh	3,654,814	$0.000075	$274	11 Winter CTWH kWh	3,654,814	$0.000075	$274	$0	0.0%
12 Total NGC Charges	9,069,311,110		$680,198	12 Total NGC Charges	9,069,311,110		$680,198	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
13 All kWh	9,069,311,110	$0.006577	$59,648,859	13 All kWh	9,069,311,110	$0.006577	$59,648,859	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
14 Summer kWh 1 to 600	1,984,067,702	$0.014169	$28,112,255	14 Summer kWh 1 to 600	1,984,067,702	$0.019091	$37,877,836	$9,765,581	34.7%
15 Summer kWh > 600	1,830,221,042	$0.056031	$102,549,115	15 Summer kWh > 600	1,830,221,042	$0.075493	$138,168,877	$35,619,762	34.7%
16 Winter kWh - All Non WH kWh	5,246,685,370	$0.023211	$121,780,814	16 Winter kWh - All Non WH kWh	5,246,685,370	$0.031273	$164,079,592	$42,298,778	34.7%
17 Summer OPWH kWh	955,675	$0.015491	$14,804	17 Summer OPWH kWh	955,675	$0.020872	$19,947	$5,143	34.7%
18 Winter OPWH kWh	2,388,854	$0.015491	$37,006	18 Winter OPWH kWh	2,388,854	$0.020872	$49,860	$12,854	34.7%
19 Summer CTWH kWh	1,337,655	$0.020404	$27,294	19 Summer CTWH kWh	1,337,655	$0.027491	$36,773	$9,479	34.7%
20 Winter CTWH kWh	3,654,814	$0.020404	$74,573	20 Winter CTWH kWh	3,654,814	$0.027491	$100,474	$25,901	34.7%
21 Total Distribution kWh Charges	9,069,311,110		$252,595,861	21 Total Distribution kWh Charges	9,069,311,110		$340,333,359	$87,737,498	34.7%
BGS per kWh Charges				BGS per kWh Charges					
22 Summer - 0 to 600 kWh	1,984,067,702	$0.067166	$133,261,891	22 Summer - 0 to 600 kWh	1,984,067,702	$0.067166	$133,261,891	$0	0.0%
23 Summer - Over 600 kWh	1,830,221,042	$0.075818	$138,763,699	23 Summer - Over 600 kWh	1,830,221,042	$0.075818	$138,763,699	$0	0.0%
24 Winter-Non-Water Heating kWh	5,246,685,370	$0.075247	$394,797,334	24 Winter-Non-Water Heating kWh	5,246,685,370	$0.075247	$394,797,334	$0	0.0%
25 Summer-OPWH & CTWH kWh	2,293,329	$0.080727	$185,134	25 Summer-OPWH & CTWH kWh	2,293,329	$0.080727	$185,134	$0	0.0%
26 Winter-OPWH & CTWH kWh	6,043,668	$0.078580	$474,911	26 Winter-OPWH & CTWH kWh	6,043,668	$0.078580	$474,911	$0	0.0%
27 Total BGS Charges	9,069,311,110		$667,482,969	27 Total BGS Charges	9,069,311,110		$667,482,969	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
28 All Non-Water Heating kWh	9,060,974,113	$0.012213	$110,661,677	28 All Non-Water Heating kWh	9,060,974,113	$0.012213	$110,661,677	$0	0.0%
29 OPWH & CTWH kWh	8,336,997	$0.012213	$101,820	29 OPWH & CTWH kWh	8,336,997	$0.012213	$101,820	$0	0.0%
30 Total Transmission Charges	9,069,311,110		$110,763,497	30 Total Transmission Charges	9,069,311,110		$110,763,497	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
31 All kWh	9,069,311,110	$0.004000	$36,277,244	31 All kWh	9,069,311,110	$0.004000	$36,277,244	$0	0.0%
RGGI Recovery Charge				RGGI Recovery Charge					
32 All kWh	9,069,311,110	$0.000000	$0	32 All kWh	9,069,311,110	$0.000000	$0	$0	#DIV/0!
Tax Act djustment				Tax Act djustment					
33 All kWh	9,069,311,110	-$0.000291	-$2,639,170	33 All kWh	9,069,311,110	-$0.000291	-$2,639,170	$0	0.0%
34 Total Charges	9,069,311,110		$1,155,790,302	34 Total Charges	9,069,311,110		$1,258,246,951	$102,456,649	8.9%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Units are included with line 1 and therefore are not added into the total on line 4.

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Residential Time-of-Day Service (RT)

Description of Charge	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Standard Customer Charge	175,897	$4.87	$856,619	1 Standard Customer Charge	175,897	$8.15	$1,433,561	$576,942	67.4%
2 Solar Water Heating Credit {3}	1,728	-$1.22	-$2,108	2 Solar Water Heating Credit {3}	1,728	-$2.04	-$3,525	-$1,417	67.2%
3 Total Customer Charges	175,897		$854,511	3 Total Customer Charges	175,897		$1,430,036	$575,525	67.4%
NGC per kWh Charges				NGC per kWh Charges					
4 On-Peak kWh - Summer	24,348,317	$0.000075	$1,826	4 On-Peak kWh - Summer	24,348,317	$0.000075	$1,826	$0	0.0%
5 On-Peak kWh - Winter	48,110,423	$0.000075	$3,608	5 On-Peak kWh - Winter	48,110,423	$0.000075	$3,608	$0	0.0%
6 Off-Peak kWh - Summer	35,786,227	$0.000075	$2,684	6 Off-Peak kWh - Summer	35,786,227	$0.000075	$2,684	$0	0.0%
7 Off-Peak kWh - Winter	89,104,150	$0.000075	$6,683	7 Off-Peak kWh - Winter	89,104,150	$0.000075	$6,683	$0	0.0%
8 Total NGC Charges	197,349,117		$14,801	8 Total NGC Charges	197,349,117		$14,801	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
9 All kWh	197,349,117	$0.006577	$1,297,965	9 All kWh	197,349,117	$0.006577	$1,297,965	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
10 On-Peak kWh - Summer	24,348,317	$0.043421	$1,057,228	10 On-Peak kWh - Summer	24,348,317	$0.055020	$1,339,644	$282,416	26.7%
11 On-Peak kWh - Winter	48,110,423	$0.031895	$1,534,482	11 On-Peak kWh - Winter	48,110,423	$0.040415	$1,944,383	$409,901	26.7%
12 Off-Peak kWh - Summer	35,786,227	$0.020283	$725,852	12 Off-Peak kWh - Summer	35,786,227	$0.025701	$919,742	$193,890	26.7%
13 Off-Peak kWh - Winter	89,104,150	$0.020283	$1,807,299	13 Off-Peak kWh - Winter	89,104,150	$0.025701	$2,290,066	$482,767	26.7%
14 Total Distribution kWh Charges	197,349,117		$5,124,861	14 Total Distribution kWh Charges	197,349,117		$6,493,835	$1,368,974	26.7%
BGS per kWh Charges				BGS per kWh Charges					
15 Summer - On Peak kWh	24,348,317	$0.128422	$3,126,860	15 Summer - On Peak kWh	24,348,317	$0.128422	$3,126,860	$0	0.0%
16 Winter - On Peak kWh	48,110,423	$0.128422	$6,178,437	16 Winter - On Peak kWh	48,110,423	$0.128422	$6,178,437	$0	0.0%
17 Summer - Off Peak KWh	35,786,227	$0.046808	$1,675,082	17 Summer - Off Peak KWh	35,786,227	$0.046808	$1,675,082	$0	0.0%
18 Winter - Off Peak kWh	89,104,150	$0.050363	$4,487,552	18 Winter - Off Peak kWh	89,104,150	$0.050363	$4,487,552	$0	0.0%
19 Total BGS Charges	197,349,117		$15,467,931	19 Total BGS Charges	197,349,117		$15,467,931	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
20 All kWh	197,349,117	$0.012213	$2,410,225	20 All kWh	197,349,117	$0.012213	$2,410,225	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
21 All kWh	197,349,117	$0.004000	$789,396	21 All kWh	197,349,117	$0.004000	$789,396	$0	0.0%
RGGI Recovery Charges				RGGI Recovery Charges					
22 All kWh	197,349,117	$0.000000	$0	22 All kWh	197,349,117	$0.000000	$0	$0	#DIV/0!
Tax Act djustment				Tax Act djustment					
23 All kWh	197,349,117	-$0.000288	-$56,837	23 All kWh	197,349,117	-$0.000288	-$56,837	$0	0.0%
24 Total Charges	197,349,117		$25,902,853	24 Total Charges	197,349,117		$27,847,352	$1,944,499	7.5%
25 Average $/kWh			$0.131254	25 Average $/kWh			$0.141107	$0.009853	7.5%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Units are included with line 1 and therefore are not added into the total on line 3.

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Residential Geothermal & Heat Pump Service (RGT)

Description of Charge	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Standard Customer Charge	6,659	$4.87	$32,429	1 Standard Customer Charge	6,659	$8.15	$54,271	$21,842	67.4%
NGC per kWh Charges				NGC per kWh Charges					
2 On-Peak Summer kWh	1,785,620	$0.000075	$134	2 On-Peak Summer kWh	1,785,620	$0.000075	$134	$0	0.0%
3 Off-Peak Summer kWh	2,570,467	$0.000075	$193	3 Off-Peak Summer kWh	2,570,467	$0.000075	$193	$0	0.0%
4 All Winter kWh	9,804,093	$0.000075	$735	4 All Winter kWh	9,804,093	$0.000075	$735	$0	0.0%
5 Total NGC Charge	14,160,180		$1,062	5 Total NGC Charge	14,160,180		$1,062	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
6 All kWh	14,160,180	$0.006577	$93,132	6 All kWh	14,160,180	$0.006577	$93,132	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
7 On-Peak Summer kWh	1,785,620	$0.043421	$77,533	7 On-Peak Summer kWh	1,785,620	$0.055020	$98,245	$20,712	26.7%
8 Off-Peak Summer kWh	2,570,467	$0.020283	$52,137	8 Off-Peak Summer kWh	2,570,467	$0.025701	$66,064	$13,927	26.7%
9 All Winter kWh	9,804,093	$0.023211	$227,563	9 All Winter kWh	9,804,093	$0.031273	$306,603	$79,040	34.7%
10 Total Distribution kWh Charges	14,160,180		$357,233	10 Total Distribution kWh Charges	14,160,180		$470,912	$113,679	31.8%
BGS per kWh Charges				BGS per kWh Charges					
11 Summer - On-Peak kWh	1,785,620	$0.128422	$229,313	11 Summer - On-Peak kWh	1,785,620	$0.128422	$229,313	$0	0.0%
12 Summer - Off-Peak kWh	2,570,467	$0.046808	$120,318	12 Summer - Off-Peak kWh	2,570,467	$0.046808	$120,318	$0	0.0%
13 Winter - All kWh	9,804,093	$0.075247	$737,729	13 Winter - All kWh	9,804,093	$0.075247	$737,729	$0	0.0%
14 Total BGS Charges	14,160,180		$1,087,360	14 Total BGS Charges	14,160,180		$1,087,360	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
15 Summer - All kWh	4,356,087	$0.012213	$53,201	15 Summer - All kWh	4,356,087	$0.012213	$53,201	$0	0.0%
16 Winter - All kWh	9,804,093	$0.012213	$119,737	16 Winter - All kWh	9,804,093	$0.012213	$119,737	$0	0.0%
17 Total Transmission Charges	14,160,180		$172,938	17 Total Transmission Charges	14,160,180		$172,938	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
18 All kWh	14,160,180	$0.004000	$56,641	18 All kWh	14,160,180	$0.004000	$56,641	$0	0.0%
RGGI Recovery Charge				RGGI Recovery Charge					
19 All kWh	14,160,180	$0.000000	$0	19 All kWh	14,160,180	$0.000000	$0	$0	#DIV/0!
Tax Act djustment				Tax Act djustment					
20 All kWh	14,160,180	-$0.000288	-$4,078	20 All kWh	14,160,180	-$0.000288	-$4,078	$0	0.0%
21 Total Charges			$1,796,717	21 Total Charges			$1,932,238	$135,521	7.5%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD

Jersey Central Power & Light Company
Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)
General Service Secondary (GS)

Description of Charge	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Single Phase Customer Charge	897,975	$2.91	$2,613,109	1 Single Phase Customer Charge	897,975	$4.01	$3,600,882	$987,773	37.8%
2 Three Phase Customer Charge	608,822	$10.44	$6,356,099	2 Three Phase Customer Charge	608,822	$14.38	$8,754,856	$2,398,757	37.7%
3 Supplemental OPWH {3}	279	$1.36	$379	3 Supplemental OPWH {3}	279	$2.01	$561	$182	48.0%
4 Supplemental CTWH {3}	564	$1.36	$767	4 Supplemental CTWH {3}	564	$2.01	$1,134	$367	47.8%
5 Supplemental Day/Night {3}	20,263	$2.38	$48,226	5 Supplemental Day/Night {3}	20,263	$3.28	$66,462	$18,236	37.8%
6 Supplemental Traffic Signal {3}	25,450	$10.85	$276,136	6 Supplemental Traffic Signal {3}	25,450	$14.95	$380,482	$104,346	37.8%
7 Total Customer Charges	1,506,797		$9,294,716	7 Total Customer Charges	1,506,797		$12,804,377	$3,509,661	37.8%
NGC per kWh Charges				NGC per kWh Charges					
8 First 1,000 kWh Summer	320,124,962	$0.000107	$34,253	8 First 1,000 kWh Summer	320,124,962	$0.000107	$34,253	$0	0.0%
9 First 1,000 kWh Winter	626,062,036	$0.000107	$66,989	9 First 1,000 kWh Winter	626,062,036	$0.000107	$66,989	$0	0.0%
10 Over 1,000 kWh Summer	2,122,055,578	$0.000107	$227,060	10 Over 1,000 kWh Summer	2,122,055,578	$0.000107	$227,060	$0	0.0%
11 Over 1,000 kWh Winter	3,574,571,071	$0.000107	$382,479	11 Over 1,000 kWh Winter	3,574,571,071	$0.000107	$382,479	$0	0.0%
12 OPWH-kWh Summer	9,981	$0.000107	$1	12 OPWH-kWh Summer	9,981	$0.000107	$1	$0	0.0%
13 OPWH-kWh Winter	26,491	$0.000107	$3	13 OPWH-kWh Winter	26,491	$0.000107	$3	$0	0.0%
14 CTWH-kWh Summer	37,912	$0.000107	$4	14 CTWH-kWh Summer	37,912	$0.000107	$4	$0	0.0%
15 CTWH-kWh Winter	104,411	$0.000107	$11	15 CTWH-kWh Winter	104,411	$0.000107	$11	$0	0.0%
16 Traffic Signal kWh Summer	2,193,479	$0.000107	$235	16 Traffic Signal kWh Summer	2,193,479	$0.000107	$235	$0	0.0%
17 Traffic Signal kWh Winter	4,593,791	$0.000107	$492	17 Traffic Signal kWh Winter	4,593,791	$0.000107	$492	$0	0.0%
18 Total NGC Charges	6,649,779,713		$711,527	18 Total NGC Charges	6,649,779,713		$711,527	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
19 All kWh	6,649,779,713	$0.006577	$43,735,601	19 All kWh	6,649,779,713	$0.006577	$43,735,601	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
20 First 1,000 kWh Summer	320,124,962	$0.055615	$17,803,750	20 First 1,000 kWh Summer	320,124,962	$0.070862	$22,684,695	$4,880,945	27.4%
21 First 1,000 kWh Winter	626,062,036	$0.051459	$32,216,526	21 First 1,000 kWh Winter	626,062,036	$0.065566	$41,048,383	$8,831,857	27.4%
22 Over 1,000 kWh Summer	2,122,055,578	$0.004448	$9,438,903	22 Over 1,000 kWh Summer	2,122,055,578	$0.005667	$12,025,689	$2,586,786	27.4%
23 Over 1,000 kWh Winter	3,574,571,071	$0.004448	$15,899,692	23 Over 1,000 kWh Winter	3,574,571,071	$0.005667	$20,257,094	$4,357,402	27.4%
24 OPWH-kWh Summer	9,981	$0.015491	$155	24 OPWH-kWh Summer	9,981	$0.020872	$208	$53	34.7%
25 OPWH-kWh Winter	26,491	$0.015491	$410	25 OPWH-kWh Winter	26,491	$0.020872	$553	$143	34.7%
26 CTWH-kWh Summer	37,912	$0.020404	$774	26 CTWH-kWh Summer	37,912	$0.027491	$1,042	$268	34.7%
27 CTWH-kWh Winter	104,411	$0.020404	$2,130	27 CTWH-kWh Winter	104,411	$0.027491	$2,870	$740	34.7%
28 Traffic Signal kWh Summer	2,193,479	$0.011655	$25,565	28 Traffic Signal kWh Summer	2,193,479	$0.014850	$32,573	$7,008	27.4%
29 Traffic Signal kWh Winter	4,593,791	$0.011655	$53,541	29 Traffic Signal kWh Winter	4,593,791	$0.014850	$68,218	$14,677	27.4%
30 Religious Hse of Wrshp Credit {4}	12,325,751	-$0.028353	-$349,472	30 Religious Hse of Wrshp Credit {4}	12,325,751	-$0.036126	-$445,280	-$95,808	27.4%
31 CBT Exemption {5}			-$102,234	31 CBT Exemption {5}			-$138,231	-$35,997	N/A
32 Total Distr. kWh Charges	6,649,779,713		$74,989,740	32 Total Distr. kWh Charges	6,649,779,713		$95,537,814	$20,548,074	27.4%
Distribution Demand Charges				Distribution Demand Charges					
33 Full Rate - Summer	5,526,403	$6.22	$34,374,227	33 Full Rate - Summer	5,526,403	$8.67	$47,913,915	$13,539,688	39.4%
34 Full Rate - Winter	8,748,222	$5.79	$50,652,208	34 Full Rate - Winter	8,748,222	$8.07	$70,598,156	$19,945,948	39.4%
35 Minimum Charge	3,637,049	$2.82	$10,256,479	35 Minimum Charge	3,637,049	$3.93	$14,293,603	$4,037,124	39.4%
36 Standby Demand	1,128	$2.86	$3,225	36 Standby Demand	1,128	$3.99	$4,499	$1,274	39.5%
37 Total Distr. kW Charges	17,912,802		$95,286,139	37 Total Distr. kW Charges	17,912,802		$132,810,173	$37,524,034	39.4%
BGS per kWh Charges				BGS per kWh Charges					
38 Summer-Non-Water Heating kWh	2,444,374,019	$0.075395	$184,293,579	38 Summer-Non-Water Heating kWh	2,444,374,019	$0.075395	$184,293,579	$0	0.0%
39 Winter-Non-Water Heating kWh	4,205,226,898	$0.075395	$317,053,082	39 Winter-Non-Water Heating kWh	4,205,226,898	$0.075395	$317,053,082	$0	0.0%
40 Summer-OPWH & CTWH kWh	47,894	$0.080727	$3,866	40 Summer-OPWH & CTWH kWh	47,894	$0.080727	$3,866	$0	0.0%
41 Winter-OPWH & CTWH kWh	130,902	$0.078580	$10,286	41 Winter-OPWH & CTWH kWh	130,902	$0.078580	$10,286	$0	0.0%
42 Total BGS Charges	6,649,779,713		$501,360,813	42 Total BGS Charges	6,649,779,713		$501,360,813	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
43 All Non-Water Heating kWh	6,649,600,917	$0.012213	$81,211,576	43 All Non-Water Heating kWh	6,649,600,917	$0.012213	$81,211,576	$0	0.0%
44 OPWH & CTWH kWh	178,796	$0.012213	$2,184	44 OPWH & CTWH kWh	178,796	$0.012213	$2,184	$0	0.0%
45 Total Transmission Charges	6,649,779,713		$81,213,760	45 Total Transmission Charges	6,649,779,713		$81,213,760	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
46 All kWh	6,649,779,713	$0.004000	$26,599,119	46 All kWh	6,649,779,713	$0.004000	$26,599,119	$0	0.0%
RGGI Recovery Charges				RGGI Recovery Charges					
47 All kWh	6,649,779,713	$0.000000	$0	47 All kWh	6,649,779,713	$0.000000	$0	$0	#DIV/0!
Tax Act djustment				Tax Act djustment					
48 All kWh	6,649,779,713	-$0.000257	-$1,708,993	48 All kWh	6,649,779,713	-$0.000257	-$1,708,993	$0	0.0%
49 Total Charges	6,649,779,713		$831,482,422	49 Total Charges	6,649,779,713		$893,064,191	$61,581,769	7.4%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Units are included in lines 1 and 2 and therefore are not added into the total on line 7.
{4} Units are included with lines 20 through 23 and therefore are not added into the total on line 32.
{5} Total distribution reduction attributable to CBT Exempt accounts.

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

General Service Secondary Time-of-Day (GST)

Description of Charge	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Single Phase Customer Charge	-1	$28.00	-$41	1 Single Phase Customer Charge	-1	$39.19	-$58	-$17	0.0%
2 Three Phase Customer Charge	2,361	$39.96	$94,361	2 Three Phase Customer Charge	2,361	$55.92	$132,048	$37,687	39.9%
3 Total Customer Charges	2,360		$94,320	3 Total Customer Charges	2,360		$131,990	$37,670	39.9%
NGC per kWh Charges				NGC per kWh Charges					
4 Summer On-Peak kWh	85,590,966	$0.000107	$9,158	4 Summer On-Peak kWh	85,590,966	$0.000107	$9,158	$0	0.0%
5 Winter On-Peak kWh	149,048,454	$0.000107	$15,948	5 Winter On-Peak kWh	149,048,454	$0.000107	$15,948	$0	0.0%
6 Summer Off-Peak kWh	102,471,609	$0.000107	$10,964	6 Summer Off-Peak kWh	102,471,609	$0.000107	$10,964	$0	0.0%
7 Winter Off-Peak kWh	191,825,104	$0.000107	$20,525	7 Winter Off-Peak kWh	191,825,104	$0.000107	$20,525	$0	0.0%
8 Total NGC Charges	528,936,132		$56,595	8 Total NGC Charges	528,936,132		$56,595	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
9 All kWh	528,936,132	$0.006577	$3,478,813	9 All kWh	528,936,132	$0.006577	$3,478,813	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
10 Summer On-Peak kWh	85,590,966	$0.004371	$374,118	10 Summer On-Peak kWh	85,590,966	$0.005346	$457,569	$83,451	22.3%
11 Winter On-Peak kWh	149,048,454	$0.004371	$651,491	11 Winter On-Peak kWh	149,048,454	$0.005346	$796,813	$145,322	22.3%
12 Summer Off-Peak kWh	102,471,609	$0.004371	$447,903	12 Summer Off-Peak kWh	102,471,609	$0.005346	$547,813	$99,910	22.3%
13 Winter Off-Peak kWh	191,825,104	$0.004371	$838,468	13 Winter Off-Peak kWh	191,825,104	$0.005346	$1,025,497	$187,029	22.3%
14 CBT Exemption {3}			-$8,020	14 CBT Exemption {3}			-$10,851	-$2,831	N/A
15 Total Distr. kWh Charges	528,936,132		$2,303,960	15 Total Distr. kWh Charges	528,936,132		$2,816,841	$512,881	22.3%
Distribution Demand Charges				Distribution Demand Charges					
16 Full Rate - Summer	472,034	$6.58	$3,105,984	16 Full Rate - Summer	472,034	$9.21	$4,347,433	$1,241,449	40.0%
17 Full Rate - Winter	855,151	$6.15	$5,259,176	17 Full Rate - Winter	855,151	$8.61	$7,362,846	$2,103,670	40.0%
18 Minimum Charge	125,438	$2.87	$360,007	18 Minimum Charge	125,438	$4.02	$504,261	$144,254	40.1%
19 Standby Demand	0	$2.86	$0	19 Standby Demand	0	$3.99	$0	$0	0.0%
20 Total Distr. kW Charges	1,452,623		$8,725,167	20 Total Distr. kW Charges	1,452,623		$12,214,540	$3,489,373	40.0%
BGS per kWh Charges {4}				BGS per kWh Charges {4}					
21 Summer On-Peak kWh	85,590,966	$0.081246	$6,953,924	21 Summer On-Peak kWh	85,590,966	$0.081246	$6,953,924	$0	0.0%
22 Winter On-Peak kWh	149,048,454	$0.082067	$12,231,959	22 Winter On-Peak kWh	149,048,454	$0.082067	$12,231,959	$0	0.0%
23 Summer Off-Peak kWh	102,471,609	$0.044299	$4,539,390	23 Summer Off-Peak kWh	102,471,609	$0.044299	$4,539,390	$0	0.0%
24 Winter Off-Peak kWh	191,825,104	$0.048511	$9,305,628	24 Winter Off-Peak kWh	191,825,104	$0.048511	$9,305,628	$0	0.0%
25 Total BGS Charges	528,936,132		$33,030,901	25 Total BGS Charges	528,936,132		$33,030,901	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
26 All kWh	528,936,132	$0.012213	$6,459,897	26 All kWh	528,936,132	$0.012213	$6,459,897	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
27 All kWh	528,936,132	$0.004000	$2,115,745	27 All kWh	528,936,132	$0.004000	$2,115,745	$0	0.0%
RGGI Recovery Charges				RGGI Recovery Charges					
28 All kWh	528,936,132	$0.000000	$0	28 All kWh	528,936,132	$0.000000	$0	$0	#DIV/0!
Tax Act djustment				Tax Act djustment					
29 All kWh	528,936,132	-$0.000200	-$105,787	29 All kWh	528,936,132	-$0.000200	-$105,787	$0	0.0%
30 Total Charges	528,936,132		$56,159,611	30 Total Charges	528,936,132		$60,199,535	$4,039,924	7.2%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Total distribution reduction attributable to CBT Exempt accounts.
{4} Based on Average BGS cost for RSCP and CIEP eligible accounts from 1/1/2019 to 12/31/2019

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

General Service Primary (GP)

Description of Charge	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Customer Charge	5,077	$49.29	$250,243	1 Customer Charge	5,077	$66.26	$336,399	$86,156	34.4%
NGC per kWh Charges				NGC per kWh Charges					
2 Summer On-Peak kWh	256,317,639	$0.000102	$26,144	2 Summer On-Peak kWh	256,317,639	$0.000102	$26,144	$0	0.0%
3 Winter On-Peak kWh	445,028,864	$0.000102	$45,393	3 Winter On-Peak kWh	445,028,864	$0.000102	$45,393	$0	0.0%
4 Summer Off-Peak kWh	368,437,714	$0.000102	$37,581	4 Summer Off-Peak kWh	368,437,714	$0.000102	$37,581	$0	0.0%
5 Winter Off-Peak kWh	661,020,578	$0.000102	$67,424	5 Winter Off-Peak kWh	661,020,578	$0.000102	$67,424	$0	0.0%
6 Total NGC Charges	1,730,804,795		$176,542	6 Total NGC Charges	1,730,804,795		$176,542	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
7 All kWh	1,730,804,795	$0.006577	$11,383,503	7 All kWh	1,730,804,795	$0.006577	$11,383,503	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
8 Summer On-Peak kWh	256,317,639	$0.003149	$807,144	8 Summer On-Peak kWh	256,317,639	$0.003726	$955,040	$147,896	18.3%
9 Winter On-Peak kWh	445,028,864	$0.003149	$1,401,396	9 Winter On-Peak kWh	445,028,864	$0.003726	$1,658,178	$256,782	18.3%
10 Summer Off-Peak kWh	368,437,714	$0.003149	$1,160,210	10 Summer Off-Peak kWh	368,437,714	$0.003726	$1,372,799	$212,589	18.3%
11 Winter Off-Peak kWh	661,020,578	$0.003149	$2,081,554	11 Winter Off-Peak kWh	661,020,578	$0.003726	$2,462,963	$381,409	18.3%
12 CBT Exemption {3}			-$8,221	12 CBT Exemption {3}			-$10,604	-$2,383	N/A
13 Total Distr. kWh Charges	1,730,804,795		$5,442,083	13 Total Distr. kWh Charges	1,730,804,795		$6,438,376	$996,293	18.3%
Distribution Demand Charges				Distribution Demand Charges					
14 Full Rate - Summer	1,370,729	$5.14	$7,045,547	14 Full Rate - Summer	1,370,729	$6.91	$9,471,737	$2,426,190	34.4%
15 Full Rate - Winter	2,474,483	$4.77	$11,803,282	15 Full Rate - Winter	2,474,483	$6.41	$15,861,433	$4,058,151	34.4%
16 Minimum Charge	130,068	$1.74	$226,318	16 Minimum Charge	130,068	$2.34	$304,359	$78,041	34.5%
17 Standby Demand	0	$1.78	$0	17 Standby Demand	0	$2.39	$0	$0	0.0%
18 kVar Demand	1,869,102	$0.33	$616,804	18 kVar Demand	1,869,102	$0.44	$822,405	$205,601	33.3%
19 Total Distr. kW Charges	5,844,381		$19,691,951	19 Total Distr. kW Charges	5,844,381		$26,459,934	$6,767,983	34.4%
BGS per kWh Charges {4}				BGS per kWh Charges {4}					
20 Summer kWh	624,755,352	$0.030084	$18,795,140	20 Summer kWh	624,755,352	$0.030084	$18,795,140	$0	0.0%
21 Winter kWh	1,106,049,442	$0.033667	$37,237,367	21 Winter kWh	1,106,049,442	$0.033667	$37,237,367	$0	0.0%
22 DSSAC - All kWh	1,730,804,795	$0.000150	$259,621	22 DSSAC - All kWh	1,730,804,795	$0.000150	$259,621	$0	0.0%
23 Capacity Obligation - kW days	147,928,017	$0.246010	$36,391,772	23 Capacity Obligation - kW days	147,928,017	$0.246010	$36,391,772	$0	0.0%
24 Total BGS Charges	1,730,804,795		$92,683,900	24 Total BGS Charges	1,730,804,795		$92,683,900	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
25 All kWh	1,730,804,795	$0.007977	$13,806,630	25 All kWh	1,730,804,795	$0.007977	$13,806,630	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
26 All kWh	1,730,804,795	$0.004000	$6,923,219	26 All kWh	1,730,804,795	$0.004000	$6,923,219	$0	0.0%
RGGI Recovery Charges				RGGI Recovery Charges					
27 All kWh	1,730,804,795	$0.000000	$0	27 All kWh	1,730,804,795	$0.000000	$0	$0	#DIV/0!
Tax Act djustment				Tax Act djustment					
28 All kWh	1,730,804,795	-$0.000144	-$249,236	28 All kWh	1,730,804,795	-$0.000144	-$249,236	$0	0.0%
29 Total Charges	1,730,804,795		$150,108,835	29 Total Charges	1,730,804,795		$157,959,267	$7,850,432	5.2%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Total distribution reduction attributable to CBT Exempt accounts.
{4} Based on BGS Energy and Capacity Cost from 1/1/2019 to 12/31/2019

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

General Service Transmission (GT)

Description of Charge	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Customer Charges	1,963	$211.68	$415,568	1 Customer Charges	1,963	$284.58	$558,685	$143,117	34.4%
NGC per kWh Charges				NGC per kWh Charges					
2 Summer kWh (w/o 230 kV)	509,506,749	$0.000100	$50,951	2 Summer kWh (w/o 230 kV)	509,506,749	$0.000100	$50,951	$0	0.0%
3 Winter kWh (w/o 230 kV)	1,009,298,855	$0.000100	$100,930	3 Winter kWh (w/o 230 kV)	1,009,298,855	$0.000100	$100,930	$0	0.0%
4 230 kV Summer kWh	54,069,647	$0.000098	$5,299	4 230 kV Summer kWh	54,069,647	$0.000098	$5,299	$0	0.0%
5 230 kV Winter kWh	104,430,393	$0.000098	$10,234	5 230 kV Winter kWh	104,430,393	$0.000098	$10,234	$0	0.0%
6 GT Prov (d) Summer	72,477,115	$0.000000	$0	6 GT Prov (d) Summer	72,477,115	$0.000000	$0	$0	0.0%
7 GT Prov (d) Winter	146,777,960	$0.000000	$0	7 GT Prov (d) Winter	146,777,960	$0.000000	$0	$0	0.0%
8 DOD Summer kWh	62,116,024	$0.000100	$6,212	8 DOD Summer kWh	62,116,024	$0.000100	$6,212	$0	0.0%
9 DOD Winter kWh	110,411,641	$0.000100	$11,041	9 DOD Winter kWh	110,411,641	$0.000100	$11,041	$0	0.0%
10 Total NGC Charges	2,069,088,385		$184,667	10 Total NGC Charges	2,069,088,385		$184,667	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
11 All kWh	2,069,088,385	$0.006577	$13,608,394	11 All kWh	2,069,088,385	$0.006577	$13,608,394	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
12 Summer On-Peak kWh	279,662,401	$0.002434	$680,698	12 Summer On-Peak kWh	279,662,401	$0.002866	$801,512	$120,814	17.7%
13 Winter On-Peak kWh	531,960,853	$0.002434	$1,294,793	13 Winter On-Peak kWh	531,960,853	$0.002866	$1,524,600	$229,807	17.7%
14 Summer Off-Peak kWh	346,030,019	$0.002434	$842,237	14 Summer Off-Peak kWh	346,030,019	$0.002866	$991,722	$149,485	17.7%
15 Winter Off-Peak kWh	692,180,036	$0.002434	$1,684,766	15 Winter Off-Peak kWh	692,180,036	$0.002866	$1,983,788	$299,022	17.7%
16 230 kV Discount {3}	158,500,040	-$0.000864	-$136,944	16 230 kV Discount {3}	158,500,040	-$0.001017	-$161,195	-$24,251	17.7%
17 DOD Summer Credit {3}	62,116,024	-$0.001582	-$98,268	17 DOD Summer Credit {3}	62,116,024	-$0.001863	-$115,722	-$17,454	17.8%
18 DOD Winter Credit {3}	110,411,641	-$0.001582	-$174,671	18 DOD Winter Credit {3}	110,411,641	-$0.001863	-$205,697	-$31,026	17.8%
19 GT Prov (d) Summer	72,477,115	$0.000000	$0	19 GT Prov (d) Summer	72,477,115	$0.000000	$0	$0	0.0%
20 GT Prov (d) Winter	146,777,960	$0.000000	$0	20 GT Prov (d) Winter	146,777,960	$0.000000	$0	$0	0.0%
20 CBT Exemption {4}			-$11,118	20 CBT Exemption {4}			-$14,630	-$3,512	N/A
21 Total Distr. kWh Charges	2,069,088,385		$4,081,493	21 Total Distr. kWh Charges	2,069,088,385		$4,804,378	$722,885	17.7%
Distribution Demand Charges				Distribution Demand Charges					
22 Full Rate - Summer	1,441,438	$3.30	$4,756,744	22 Full Rate - Summer	1,441,438	$4.44	$6,399,983	$1,643,239	34.5%
23 Full Rate - Winter	2,755,828	$3.30	$9,094,233	23 Full Rate - Winter	2,755,828	$4.44	$12,235,878	$3,141,645	34.5%
24 Minimum Charge	617,903	$1.00	$617,903	24 Minimum Charge	617,903	$1.34	$827,990	$210,087	34.0%
25 Standby Demand	223,398	$0.85	$189,888	25 Standby Demand	223,398	$1.14	$254,674	$64,786	34.1%
26 230 kV Discount {5}	277,692	-$0.88	-$244,369	26 230 kV Discount {5}	277,692	-$1.18	-$327,676	-$83,307	34.1%
27 Minimum Charge Reduction	0	-$0.42	$0	27 Minimum Charge Reduction	0	-$0.56	$0	$0	0.0%
28 DOD Summer kW Credit {5}	134,908	-$2.19	-$295,449	28 DOD Summer kW Credit {5}	134,908	-$2.94	-$396,630	-$101,181	34.2%
29 DOD Winter kW Credit {5}	230,086	-$2.19	-$503,889	29 DOD Winter kW Credit {5}	230,086	-$2.94	-$676,453	-$172,564	34.2%
30 DOD Minimum kW Credit {5}	22,169	-$0.66	-$14,632	30 DOD Minimum kW Credit {5}	22,169	-$0.89	-$19,730	-$5,098	34.8%
31 GT Prov (d) Summer	269,650	$0.35	$94,377	31 GT Prov (d) Summer	269,650	$0.47	$126,735	$32,358	34.3%
32 GT Prov (d) Winter	555,472	$0.35	$194,415	32 GT Prov (d) Winter	555,472	$0.47	$261,072	$66,657	34.3%
33 kVar Demand	1,953,485	$0.32	$625,115	33 kVar Demand	1,953,485	$0.43	$839,999	$214,884	34.4%
34 Total Distr. kW Charges	7,817,174		$14,514,336	34 Total Distr. kW Charges	7,817,174		$19,525,842	$5,011,506	34.5%
BGS per kWh Charges {6}				BGS per kWh Charges {6}					
35 Summer kWh	698,169,535	$0.028586	$19,957,874	35 Summer kWh	698,169,535	$0.028586	$19,957,874	$0	0.0%
36 Winter kWh	1,370,918,850	$0.037774	$51,785,089	36 Winter kWh	1,370,918,850	$0.037774	$51,785,089	$0	0.0%
37 DSSAC - All kWh	2,069,088,385	$0.000150	$310,363	37 DSSAC - All kWh	2,069,088,385	$0.000150	$310,363	$0	0.0%
38 Capacity Obligation - kW days	125,566,965	$0.246010	$30,890,729	38 Capacity Obligation - kW days	125,566,965	$0.246010	$30,890,729	$0	0.0%
39 Total BGS Charges	2,069,088,385		$102,944,055	39 Total BGS Charges	2,069,088,385		$102,944,055	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
40 All kWh - Excluding 230 kV kWh	1,691,333,269	$0.006995	$11,830,876	40 All kWh - Excluding 230 kV kWh	1,691,333,269	$0.006995	$11,830,876	$0	0.0%
41 230 kV kWh	377,755,115	$0.001614	$609,697	41 230 kV kWh	377,755,115	$0.001614	$609,697	$0	0.0%
	2,069,088,385		12,440,573		2,069,088,385		12,440,573	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
42 All kWh	2,069,088,385	$0.004000	$8,276,354	42 All kWh	2,069,088,385	$0.004000	$8,276,354	$0	0.0%
RGGI Recovery Charges				RGGI Recovery Charges					
43 All kWh	2,069,088,385	$0.000000	$0	43 All kWh	2,069,088,385	$0.000000	$0	$0	#DIV/0!
Tax Act djustment				Tax Act djustment					
44 All kWh	2,069,088,385	-$0.000087	-$180,011	44 All kWh	2,069,088,385	-$0.000087	-$180,011	$0	0.0%
45 Total Charges	2,069,088,385		$156,285,429	45 Total Charges	2,069,088,385		$162,162,937	$5,877,508	3.8%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Units are included in lines 12 through 15 and are therefore excluded from the total on line 21.
{4} Total distribution reduction attributable to CBT Exempt accounts.
{5} Units are included in lines 22 to 24 and are therefore excluded from the total on line 34.
{6} Based on BGS Energy and Capacity Cost from 1/1/2019 to 12/31/2019

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Lighting Summary

Description of Charge	Weather Normalized 2019/2020 6+6 Units (a)	Revenue Based on Current Rates {1} (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (c)	Revenue Based on Proposed Rates {2} (d)	Change in Revenue (e) = (d) - (b)	Percentage Change in Revenue (f) = (e) / (b)
Distribution Charges			Distribution Charges				
1 Fixture Charges	2,556,585	$12,467,041	1 Fixture Charges	2,556,585	$14,603,280	$2,136,239	17.1%
2 Miscellaneous Charges	145,315	$369,071	2 Miscellaneous Charges	145,315	$432,393	$63,322	17.2%
3 kWh Charges	115,683,995	$4,997,199	3 kWh Charges	115,683,995	$5,857,693	$860,494	17.2%
4 Total Distribution Charges	115,683,995	$17,833,311	4 Total Distribution Charges	115,683,995	$20,893,366	$3,060,055	17.2%
5 NGC	115,683,995	$12,379	5 NGC	115,683,995	$12,379	$0	0.0%
6 SBC	115,683,995	$760,853	6 SBC	115,683,995	$760,853	$0	0.0%
7 BGS	115,683,995	$6,139,921	7 BGS	115,683,995	$6,139,921	$0	0.0%
8 Transmission	115,683,995	$0	8 Transmission	115,683,995	$0	$0	0.0%
9 System Control Charges	115,683,995	$462,736	9 System Control Charges	115,683,995	$462,736	$0	0.0%
10 RGGI Recovery Charges	115,683,995	$0	10 RGGI Recovery Charges	115,683,995	$0	$0	0.0%
11 Storm Recovery Charges	115,683,995	-$170,055	11 Storm Recovery Charges	115,683,995	-$170,055	$0	0.0%
12 Total Charges {3}	115,683,995	$25,039,145	12 Total Charges {3}	115,683,995	$28,099,200	$3,060,055	12.2%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Total of lines 4 through 11.

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Outdoor Lighting Service (OL)

Description of Charge	Monthly kWh Per Unit	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Area Lighting Fixture Charges					Area Lighting Fixture Charges					
1 100 Watt Lamp (121 Watt Total)	42	26,121	$2.31	$60,339	1 100 Watt Lamp (121 Watt Total)	26,121	$2.71	$70,788	$10,449	
2 175 Watt Lamp (211 Watt Total)	74	40,051	$2.31	$92,517	2 175 Watt Lamp (211 Watt Total)	40,051	$2.71	$108,537	$16,020	
High Pressure Sodium					High Pressure Sodium					
3 70 Watt HPS (99 Watt Total)	35	220	$9.58	$2,106	3 70 Watt HPS (99 Watt Total)	220	$11.22	$2,466	$360	
4 100 Watt HPS (137 Watt Total)	48	786	$9.58	$7,533	4 100 Watt HPS (137 Watt Total)	786	$11.22	$8,823	$1,290	
Flood Lighting Fixture Charges					Flood Lighting Fixture Charges					
5 150 Watt Lamp (176 Watt Total)	62	61,845	$11.25	$695,759	5 150 Watt Lamp (176 Watt Total)	61,845	$13.18	$815,121	$119,362	
6 250 Watt Lamp (293 Watt Total)	103	59,261	$11.82	$700,462	6 250 Watt Lamp (293 Watt Total)	59,261	$13.85	$820,761	$120,299	
7 400 Watt Lamp (498 Watt Total)	174	62,311	$12.13	$755,830	7 400 Watt Lamp (498 Watt Total)	62,311	$14.21	$885,436	$129,606	
8 Total Fixture Charges		250,594		$2,314,546	8 Total Fixture Charges	250,594		$2,711,932	$397,386	17.2%
Miscellaneous Charges					Miscellaneous Charges					
9 Spans Furnished Prior to 2/6/79		49,338	$0.59	$29,109	9 Spans Furnished Prior to 2/6/79	49,338	$0.69	$34,043	$4,934	
10 Spans Furnished After 2/6/79		21,745	$2.92	$63,496	10 Spans Furnished After 2/6/79	21,745	$3.42	$74,368	$10,872	
11 Transformers		656	$2.53	$1,658	11 Transformers	656	$2.96	$1,940	$282	
12 Poles Furnished Prior to 2/6/79		34,606	$0.63	$21,802	12 Poles Furnished Prior to 2/6/79	34,606	$0.74	$25,609	$3,807	
13 35' Poles Furnished After 2/6/79		11,418	$5.78	$65,998	13 35' Poles Furnished After 2/6/79	11,418	$6.77	$77,302	$11,304	
14 40' Poles Furnished After 2/6/79		990	$6.47	$6,404	14 40' Poles Furnished After 2/6/79	990	$7.58	$7,503	$1,099	
15 Total Miscellaneous Charges		118,753		$188,467	15 Total Miscellaneous Charges	118,753		$220,765	$32,298	17.1%
NGC per kWh Charges					NGC per kWh Charges					
16 Summer kWh		8,250,447	$0.000107	$883	16 Summer kWh	8,250,447	$0.000107	$883	$0	0.0%
17 Winter kWh		16,490,114	$0.000107	$1,764	17 Winter kWh	16,490,114	$0.000107	$1,764	$0	0.0%
18 Total NGC Charge		24,740,561		$2,647	18 Total NGC Charge	24,740,561		$2,647	$0	0.0%
SBC per kWh Charges					SBC per kWh Charges					
19 All kWh		24,740,561	$0.006577	$162,719	19 All kWh	24,740,561	$0.006577	$162,719	$0	0.0%
Distribution per kWh Charges					Distribution per kWh Charges					
20 All kWh		24,740,561	$0.043172	$1,068,099	20 All kWh	24,740,561	$0.050606	$1,252,021	$183,922	17.2%
21 CBT Exemption {3}		0		-$170	21 CBT Exemption {3}	0		-$200	-$30	N/A
22 Total Distribution Charge		24,740,561		$1,067,929	22 Total Distribution Charge	24,740,561		$1,251,821	$183,892	17.2%
BGS per kWh Charges					BGS per kWh Charges					
23 Summer kWh		8,250,447	$0.052138	$430,162	23 Summer kWh	8,250,447	$0.052138	$430,162	$0	0.0%
24 Winter kWh		16,490,114	$0.053545	$882,963	24 Winter kWh	16,490,114	$0.053545	$882,963	$0	0.0%
25 Total BGS Charge		24,740,561		$1,313,125	25 Total BGS Charge	24,740,561		$1,313,125	$0	0.0%
Transmission per kWh Charges					Transmission per kWh Charges					
26 All kWh		24,740,561	$0.000000	$0	26 All kWh	24,740,561	$0.000000	$0	$0	#DIV/0!
ZEC Recovery Charges					ZEC Recovery Charges					
27 All kWh		24,740,561	$0.004000	$98,962	27 All kWh	24,740,561	$0.004000	$98,962	$0	0.0%
RGGI Recovery Charges					RGGI Recovery Charges					
28 All kWh		24,740,561	$0.000000	$0	28 All kWh	24,740,561	$0.000000	$0	$0	#DIV/0!
Tax Act djustment					Tax Act djustment					
29 All kWh		24,740,561	-$0.001470	-$36,369	29 All kWh	24,740,561	-$0.001470	-$36,369	$0	0.0%
30 Total Charges		24,740,561		$5,112,026	30 Total Charges	24,740,561		$5,725,602	$613,576	12.0%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Total distribution reduction attributable to CBT Exempt accounts.

Jersey Central Power & Light Company
Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)
Sodium Vapor Street Lighting Service (SVL)

Description of Charge	Monthly kWh Per Unit	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Company Lighting Fixture Charges					Company Lighting Fixture Charges					
1 50 Watt Lamp (60 Watt Total)	21	563,439	$5.59	$3,149,626	1 50 Watt Lamp (60 Watt Total)	563,439	$6.55	$3,690,527	$540,901	
2 70 Watt Lamp (85 Watt Total)	30	215,750	$5.59	$1,206,041	2 70 Watt Lamp (85 Watt Total)	215,750	$6.55	$1,413,161	$207,120	
3 100 Watt Lamp (121 Watt Total)	42	339,566	$5.59	$1,898,173	3 100 Watt Lamp (121 Watt Total)	339,566	$6.55	$2,224,157	$325,984	
4 150 Watt Lamp (176 Watt Total)	62	91,953	$5.59	$514,019	4 150 Watt Lamp (176 Watt Total)	91,953	$6.55	$602,294	$88,275	
5 250 Watt Lamp (293 Watt Total)	103	95,956	$6.61	$634,269	5 250 Watt Lamp (293 Watt Total)	95,956	$7.74	$742,699	$108,430	
6 400 Watt Lamp (498 Watt Total)	174	13,111	$6.61	$86,666	6 400 Watt Lamp (498 Watt Total)	13,111	$7.74	$101,481	$14,815	
Company Seasonal Fixture Charges					Company Seasonal Fixture Charges					
7 50 Watt Lamp (60 Watt Total)		156	$5.59	$872	7 50 Watt Lamp (60 Watt Total)	156	$6.55	$1,022	$150	
8 70 Watt Lamp (85 Watt Total)		216	$5.59	$1,207	8 70 Watt Lamp (85 Watt Total)	216	$6.55	$1,415	$208	
9 100 Watt Lamp (121 Watt Total)		264	$5.59	$1,476	9 100 Watt Lamp (121 Watt Total)	264	$6.55	$1,729	$253	
10 150 Watt Lamp (176 Watt Total)		168	$5.59	$939	10 150 Watt Lamp (176 Watt Total)	168	$6.55	$1,100	$161	
11 250 Watt Lamp (293 Watt Total)		0	$6.61	$0	11 250 Watt Lamp (293 Watt Total)	0	$7.74	$0	$0	
12 400 Watt Lamp (498 Watt Total)		0	$6.61	$0	12 400 Watt Lamp (498 Watt Total)	0	$7.74	$0	$0	
Contribution Lighting Fixture Charges					Contribution Lighting Fixture Charges					
13 50 Watt Lamp (60 Watt Total)	21	119,603	$1.57	$187,776	13 50 Watt Lamp (60 Watt Total)	119,603	$1.84	$220,069	$32,293	
14 70 Watt Lamp (85 Watt Total)	30	84,433	$1.57	$132,560	14 70 Watt Lamp (85 Watt Total)	84,433	$1.84	$155,357	$22,797	
15 100 Watt Lamp (121 Watt Total)	42	139,664	$1.57	$219,273	15 100 Watt Lamp (121 Watt Total)	139,664	$1.84	$256,982	$37,709	
16 150 Watt Lamp (176 Watt Total)	62	31,438	$1.57	$49,358	16 150 Watt Lamp (176 Watt Total)	31,438	$1.84	$57,846	$8,488	
17 250 Watt Lamp (293 Watt Total)	103	6,350	$1.57	$9,969	17 250 Watt Lamp (293 Watt Total)	6,350	$1.84	$11,683	$1,714	
18 400 Watt Lamp (498 Watt Total)	174	1,848	$1.57	$2,901	18 400 Watt Lamp (498 Watt Total)	1,848	$1.84	$3,400	$499	
Contribution Seasonal Fixture Charges					Contribution Seasonal Fixture Charges					
19 50 Watt Lamp (60 Watt Total)		208	$1.57	$327	19 50 Watt Lamp (60 Watt Total)	208	$1.84	$383	$56	
20 70 Watt Lamp (85 Watt Total)		12	$1.57	$19	20 70 Watt Lamp (85 Watt Total)	12	$1.84	$22	$3	
21 100 Watt Lamp (121 Watt Total)		768	$1.57	$1,206	21 100 Watt Lamp (121 Watt Total)	768	$1.84	$1,413	$207	
22 150 Watt Lamp (176 Watt Total)		0	$1.57	$0	22 150 Watt Lamp (176 Watt Total)	0	$1.84	$0	$0	
23 250 Watt Lamp (293 Watt Total)		0	$1.57	$0	23 250 Watt Lamp (293 Watt Total)	0	$1.84	$0	$0	
24 400 Watt Lamp (498 Watt Total)		0	$1.57	$0	24 400 Watt Lamp (498 Watt Total)	0	$1.84	$0	$0	
Contribution Reduced Hours Fixture Charges					Contribution Reduced Hours Fixture Charges					
25 150 Watt Lamp (176 Watt Total)	29	0	$1.57	$0	25 150 Watt Lamp (176 Watt Total)	0	$1.84	$0	$0	
Customer Lighting Fixture Charges					Customer Lighting Fixture Charges					
26 50 Watt Lamp (60 Watt Total)	21	204	$0.76	$155	26 50 Watt Lamp (60 Watt Total)	204	$0.89	$182	$27	
27 70 Watt Lamp (85 Watt Total)	30	168	$0.76	$128	27 70 Watt Lamp (85 Watt Total)	168	$0.89	$150	$22	
28 100 Watt Lamp (121 Watt Total)	42	2,628	$0.76	$1,997	28 100 Watt Lamp (121 Watt Total)	2,628	$0.89	$2,339	$342	
29 150 Watt Lamp (176 Watt Total)	62	4,423	$0.76	$3,361	29 150 Watt Lamp (176 Watt Total)	4,423	$0.89	$3,936	$575	
30 250 Watt Lamp (293 Watt Total)	103	792	$0.76	$602	30 250 Watt Lamp (293 Watt Total)	792	$0.89	$705	$103	
31 400 Watt Lamp (498 Watt Total)	174	432	$0.76	$328	31 400 Watt Lamp (498 Watt Total)	432	$0.89	$384	$56	
32 Total Fixture Charges		1,713,550		$8,103,248	32 Total Fixture Charges	1,713,550		$9,494,436	$1,391,188	17.2%
Miscellaneous Charges					Miscellaneous Charges					
33 Pole Charge		20,775	$7.45	$154,777	33 Pole Charge	20,775	$8.73	$181,369	$26,592	
34 Fixture Service		660	$0.89	$587	34 Fixture Service	660	$1.04	$686	$99	
35 Total Miscellaneous Charges		21,435		$155,364	35 Total Miscellaneous Charges	21,435		$182,055	$26,691	17.2%
NGC per kWh Charges					NGC per kWh Charges					
36 Summer kWh		21,648,825	$0.000107	$2,316	36 Summer kWh	21,648,825	$0.000107	$2,316	$0	0.0%
37 Winter kWh		43,135,606	$0.000107	$4,616	37 Winter kWh	43,135,606	$0.000107	$4,616	$0	0.0%
38 All kWh		64,784,431		$6,932	38 All kWh	64,784,431		$6,932	$0	0.0%
SBC per kWh Charges					SBC per kWh Charges					
39 All kWh		64,784,431	$0.006577	$426,087	39 All kWh	64,784,431	$0.006577	$426,087	$0	0.0%
Distribution per kWh Charges					Distribution per kWh Charges					
40 Seasonal Distr. Charge {3}		68,244	$0.043172	$2,946	40 Seasonal Distr. Charge {3}	68,244	$0.050606	$3,454	$508	
41 Reduced Lighting Hours Adj {4}		0	$0.043172	$0	41 Reduced Lighting Hours Adj {4}	0	$0.050606	$0	$0	
42 All kWh		64,784,431	$0.043172	$2,796,873	42 All kWh	64,784,431	$0.050606	$3,278,481	$481,608	
43 Total Distribution Charge		64,784,431		$2,799,819		64,784,431		$3,281,935	$482,116	17.2%
BGS per kWh Charges					BGS per kWh Charges					
44 Summer kWh		21,648,825	$0.052138	$1,128,726	44 Summer kWh	21,648,825	$0.052138	$1,128,726	$0	0.0%
45 Winter kWh		43,135,606	$0.053545	$2,309,696	45 Winter kWh	43,135,606	$0.053545	$2,309,696	$0	0.0%
46 Total BGS Charge		64,784,431		$3,438,422	46 Total BGS Charge	64,784,431		$3,438,422	$0	0.0%
Transmission per kWh Charges					Transmission per kWh Charges					
47 All kWh		64,784,431	$0.000000	$0	47 All kWh	64,784,431	$0.000000	$0	$0	0.0%
System Control Charges					System Control Charges					
48 All kWh		64,784,431	$0.004000	$259,138	48 All kWh	64,784,431	$0.004000	$259,138	$0	0.0%
RGGI Recovery Charges					RGGI Recovery Charges					
49 All kWh		64,784,431	$0.000000	$0	49 All kWh	64,784,431	$0.000000	$0	$0	0.0%
Tax Act djustment					Tax Act djustment					
50 All kWh		64,784,431	-$0.001470	-$95,233	50 All kWh	64,784,431	-$0.001470	-$95,233	$0	0.0%
50 Total Charges		64,784,431		$15,093,777	50 Total Charges	64,784,431		$16,993,772	$1,899,995	12.6%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Distribution kWh charge applied to kWh that seasonal lights would have used if they continued to operate
{4} Distribution kWh charge applied to additional kWh that lights would have used on the standard illumination schedu

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Mercury Vapor Street Lighting Service (MVL)

Description of Charge	Monthly kWh Per Unit	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Company Lighting Fixture Charges					Company Lighting Fixture Charges					
1 100 Watt Lamp (121 Watt Total)	42	437,572	$3.90	$1,706,531	1 100 Watt Lamp (121 Watt Total)	437,572	$4.57	$1,999,705	$293,174	
2 175 Watt Lamp (211 Watt Total)	74	18,877	$3.90	$73,622	2 175 Watt Lamp (211 Watt Total)	18,877	$4.57	$86,270	$12,648	
3 250 Watt Lamp (295 Watt Total)	103	5,779	$3.90	$22,539	3 250 Watt Lamp (295 Watt Total)	5,779	$4.57	$26,411	$3,872	
4 400 Watt Lamp (468 Watt Total)	164	1,543	$4.23	$6,525	4 400 Watt Lamp (468 Watt Total)	1,543	$4.96	$7,651	$1,126	
5 700 Watt Lamp (803 Watt Total)	281	0	$5.12	$0	5 700 Watt Lamp (803 Watt Total)	0	$6.00	$0	$0	
6 1000 Watt Lamp (1135 Watt Total)	397	0	$5.12	$0	6 1000 Watt Lamp (1135 Watt Total)	0	$6.00	$0	$0	
Company Seasonal Fixture Charges					Company Seasonal Fixture Charges					
7 100 Watt Lamp (121 Watt Total)		0	$3.90	$0	7 100 Watt Lamp (121 Watt Total)	0	$4.57	$0	$0	
8 175 Watt Lamp (211 Watt Total)		0	$3.90	$0	8 175 Watt Lamp (211 Watt Total)	0	$4.57	$0	$0	
9 250 Watt Lamp (295 Watt Total)		0	$3.90	$0	9 250 Watt Lamp (295 Watt Total)	0	$4.57	$0	$0	
10 400 Watt Lamp (468 Watt Total)		0	$4.23	$0	10 400 Watt Lamp (468 Watt Total)	0	$4.96	$0	$0	
11 700 Watt Lamp (803 Watt Total)		0	$5.12	$0	11 700 Watt Lamp (803 Watt Total)	0	$6.00	$0	$0	
12 1000 Watt Lamp (1135 Watt Total)		0	$5.12	$0	12 1000 Watt Lamp (1135 Watt Total)	0	$6.00	$0	$0	
Contribution Lighting Fixture Charges					Contribution Lighting Fixture Charges					
13 100 Watt Lamp (121 Watt Total)	42	11,497	$1.48	$17,016	13 100 Watt Lamp (121 Watt Total)	11,497	$1.73	$19,890	$2,874	
14 175 Watt Lamp (211 Watt Total)	74	1,084	$1.48	$1,604	14 175 Watt Lamp (211 Watt Total)	1,084	$1.73	$1,874	$270	
15 250 Watt Lamp (295 Watt Total)	103	0	$1.48	$0	15 250 Watt Lamp (295 Watt Total)	0	$1.73	$0	$0	
16 400 Watt Lamp (468 Watt Total)	164	0	$1.48	$0	16 400 Watt Lamp (468 Watt Total)	0	$1.73	$0	$0	
17 700 Watt Lamp (803 Watt Total)	281	0	$1.48	$0	17 700 Watt Lamp (803 Watt Total)	0	$1.73	$0	$0	
18 1000 Watt Lamp (1135 Watt Total)	397	0	$1.48	$0	18 1000 Watt Lamp (1135 Watt Total)	0	$1.73	$0	$0	
Customer Lighting Fixture Charges					Customer Lighting Fixture Charges					
19 100 Watt Lamp (121 Watt Total)	42	510	$0.75	$383	19 100 Watt Lamp (121 Watt Total)	510	$0.88	$449	$66	
20 175 Watt Lamp (211 Watt Total)	74	0	$0.75	$0	20 175 Watt Lamp (211 Watt Total)	0	$0.88	$0	$0	
21 250 Watt Lamp (295 Watt Total)	103	36	$0.75	$27	21 250 Watt Lamp (295 Watt Total)	36	$0.88	$32	$5	
22 400 Watt Lamp (468 Watt Total)	164	60	$0.75	$45	22 400 Watt Lamp (468 Watt Total)	60	$0.88	$53	$8	
23 700 Watt Lamp (803 Watt Total)	281	0	$0.75	$0	23 700 Watt Lamp (803 Watt Total)	0	$0.88	$0	$0	
24 1000 Watt Lamp (1135 Watt Total)	397	0	$0.75	$0	24 1000 Watt Lamp (1135 Watt Total)	0	$0.88	$0	$0	
25 Total Fixture Charges		476,958		$1,828,292	25 Total Fixture Charges	476,958		$2,142,335	$314,043	17.2%
Miscellaneous Charges					Miscellaneous Charges					
26 Pole Charge		3,159	$7.45	$23,535	26 Pole Charge	3,159	$8.73	$27,578	$4,043	
27 Fixture Service		288	$0.73	$210	27 Fixture Service	288	$0.86	$248	$38	
28 Total Miscellaneous Charges		3,447		$23,745	28 Total Miscellaneous Charges	3,447		$27,826	$4,081	17.2%
		480,405								
NGC per kWh Charges					NGC per kWh Charges					
29 Summer kWh		7,101,957	$0.000107	$760	29 Summer kWh	7,101,957	$0.000107	$760	$0	0.0%
30 Winter kWh		14,119,284	$0.000107	$1,511	30 Winter kWh	14,119,284	$0.000107	$1,511	$0	0.0%
31 Total NGC Charges		21,221,240		$2,271	31 Total NGC Charges	21,221,240		$2,271	$0	0.0%
SBC per kWh Charges					SBC per kWh Charges					
32 All kWh		21,221,240	$0.006577	$139,572	32 All kWh	21,221,240	$0.006577	$139,572	$0	0.0%
Distribution per kWh Charges					Distribution per kWh Charges					
33 Seasonal Distr. Charge {3}		0	$0.043172	$0	33 Seasonal Distr. Charge {3}	0	$0.050606	$0	$0	
34 All kWh		21,221,240	$0.043172	$916,163	34 All kWh	21,221,240	$0.050606	$1,073,922	$157,759	
35 Total Distribition kWh Charges		21,221,240		$916,163	35 All kWh	21,221,240		$1,073,922	$157,759	17.2%
BGS per kWh Charges					BGS per kWh Charges					
36 Summer kWh		7,101,957	$0.052138	$370,282	36 Summer kWh	7,101,957	$0.052138	$370,282	$0	0.0%
37 Winter kWh		14,119,284	$0.053545	$756,017	37 Winter kWh	14,119,284	$0.053545	$756,017	$0	0.0%
38 Total BGS Charges		21,221,240		$1,126,299	38 Total BGS Charges	21,221,240		$1,126,299	$0	0.0%
Transmission per kWh Charges					Transmission per kWh Charges					
39 All kWh		21,221,240	$0.000000	$0	39 All kWh	21,221,240	$0.000000	$0	$0	0.0%
System Control Charges					System Control Charges					
40 All kWh		21,221,240	$0.004000	$84,885	40 All kWh	21,221,240	$0.004000	$84,885	$0	0.0%
RGGI Recovery Charges					RGGI Recovery Charges					
41 All kWh		21,221,240	$0.000000	$0	41 All kWh	21,221,240	$0.000000	$0	$0	0.0%
Tax Act djustment					Tax Act djustment					
42 All kWh		21,221,240	-$0.001470	-$31,195	42 All kWh	21,221,240	-$0.001470	-$31,195	$0	0.0%
42 Total Charges		21,221,240		$4,090,032	42 Total Charges	21,221,240		$4,565,915	$475,883	11.6%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Distribution kWh charge applied to kWh that seasonal lights would have used if they continued to operate

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Incandescent Street Lighting Service (ISL)

Description of Charge	Monthly kWh Per Unit	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Company Lighting Fixture Charges					Company Lighting Fixture Charges					
1 105 Watt Lamp	37	92,680	$1.65	$152,922	1 105 Watt Lamp	92,680	$1.93	$178,873	$25,951	
2 205 Watt Lamp	72	12,710	$1.65	$20,972	2 205 Watt Lamp	12,710	$1.93	$24,530	$3,558	
3 327 Watt Lamp	114	2,838	$1.65	$4,683	3 327 Watt Lamp	2,838	$1.93	$5,477	$794	
4 448 Watt Lamp	157	193	$1.65	$319	4 448 Watt Lamp	193	$1.93	$373	$54	
5 690 Watt Lamp	242	36	$1.65	$59	5 690 Watt Lamp	36	$1.93	$69	$10	
6 860 Watt Lamp	301	0	$1.65	$0	6 860 Watt Lamp	0	$1.93	$0	$0	
7 Seasonal 105 Watt Lamp	0	72	$1.65	$119	7 Seasonal 105 Watt Lamp	72	$1.93	$139	$20	
8 Seasonal 205 Watt Lamp	0	0	$1.65	$0	8 Seasonal 205 Watt Lamp	0	$1.93	$0	$0	
9 Seasonal 327 Watt Lamp	0	0	$1.65	$0	9 Seasonal 327 Watt Lamp	0	$1.93	$0	$0	
10 Seasonal 448 Watt Lamp	0	0	$1.65	$0	10 Seasonal 448 Watt Lamp	0	$1.93	$0	$0	
11 Seasonal 690 Watt Lamp	0	0	$1.65	$0	11 Seasonal 690 Watt Lamp	0	$1.93	$0	$0	
12 Seasonal 860 Watt Lamp	0	0	$1.65	$0	12 Seasonal 860 Watt Lamp	0	$1.93	$0	$0	
13 Fire Alarm/Police Box Lamp	9	144	$0.97	$140	13 Fire Alarm/Police Box Lamp	144	$1.14	$164	$24	
14 Fire Alarm/Police Box Lamp-24 hr.	18	1,020	$0.28	$286	14 Fire Alarm/Police Box Lamp-24 hr	1,020	$0.33	$337	$51	
Customer Lighting Fixture Charges					Customer Lighting Fixture Charges					
15 105 Watt Lamp	37	80	$0.75	$60	15 105 Watt Lamp	80	$0.88	$70	$10	
16 205 Watt Lamp	72	48	$0.75	$36	16 205 Watt Lamp	48	$0.88	$42	$6	
17 327 Watt Lamp	114	0	$0.75	$0	17 327 Watt Lamp	0	$0.88	$0	$0	
18 448 Watt Lamp	157	0	$0.75	$0	18 448 Watt Lamp	0	$0.88	$0	$0	
19 690 Watt Lamp	242	12	$0.75	$9	19 690 Watt Lamp	12	$0.88	$11	$2	
20 860 Watt Lamp	301	0	$0.75	$0	20 860 Watt Lamp	0	$0.88	$0	$0	
21 Total Fixture Charges		109,833		$179,605	21 Total Fixture Charges	109,833		$210,085	$30,480	17.0%
Miscellaneous Charges					Miscellaneous Charges					
22 Fixture Service		1,680	$0.89	$1,495	22 Fixture Service	1,680	$1.04	$1,747	$252	16.9%
		111,513								
NGC per kWh Charges					NGC per kWh Charges					
23 Summer kWh		1,587,871	$0.000107	$170	23 Summer kWh	1,587,871	$0.000107	$170	$0	0.0%
24 Winter kWh		3,154,612	$0.000107	$338	24 Winter kWh	3,154,612	$0.000107	$338	$0	0.0%
25 Total NGC Charges		4,742,483		$508	25 Total NGC Charges	4,742,483		$508	$0	0.0%
SBC per kWh Charges					SBC per kWh Charges					
26 All kWh		4,742,483	$0.006577	$31,191	26 All kWh	4,742,483	$0.006577	$31,191	$0	0.0%
Distribution per kWh Charges					Distribution per kWh Charges					
27 Seasonal Distr. Charge {3}		2,664	$0.043172	$115	27 Seasonal Distr. Charge {3}	2,664	$0.050606	$135	$20	
28 All kWh		4,742,483	$0.043172	$204,742	28 All kWh	4,742,483	$0.050606	$239,998	$35,256	
29 Total Distribition kWh Charges		4,742,483		$204,857	29 Total Distribition kWh Charges	4,742,483		$240,133	$35,276	17.2%
BGS per kWh Charges					BGS per kWh Charges					
30 Summer kWh		1,587,871	$0.052138	$82,788	30 Summer kWh	1,587,871	$0.052138	$82,788	$0	0.0%
31 Winter kWh		3,154,612	$0.053545	$168,914	31 Winter kWh	3,154,612	$0.053545	$168,914	$0	0.0%
32 Total BGS Charges		4,742,483		$251,702	32 Total BGS Charges	4,742,483		$251,702	$0	0.0%
Transmission per kWh Charges					Transmission per kWh Charges					
33 All kWh		4,742,483	$0.000000	$0	33 All kWh	4,742,483	$0.000000	$0	$0	0.0%
System Control Charges					System Control Charges					
34 All kWh		4,742,483	$0.004000	$18,970	34 All kWh	4,742,483	$0.004000	$18,970	$0	0.0%
RGGI Recovery Charges					RGGI Recovery Charges					
35 All kWh		4,742,483	$0.000000	$0	35 All kWh	4,742,483	$0.000000	$0	$0	0.0%
Tax Act djustment					Tax Act djustment					
36 All kWh		4,742,483	-$0.001470	-$6,971	36 All kWh	4,742,483	-$0.001470	-$6,971	$0	0.0%
37 Total Charges		4,742,483		$681,357	37 Total Charges	4,742,483		$747,365	$66,008	9.7%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD
{3} Distribution kWh charge applied to kWh that seasonal lights would have used if they continued to operate

Jersey Central Power & Light Company

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Excludes SUT)

LED Street Lighting Service (LED)

Description of Charge	Monthly kWh Per Unit	Weather Normalized 2019/2020 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2019/2020 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Company Lighting Fixture Charges					Company Lighting Fixture Charges					
1 50 Watt Cobra Head Lamp	18	1,771	$5.97	$10,570	1 50 Watt Cobra Head Lamp	1,771	$6.65	$11,774	$1,204	
2 90 Watt Cobra Head Lamp	32	2,138	$6.60	$14,108	2 90 Watt Cobra Head Lamp	2,138	$7.19	$15,369	$1,261	
3 130 Watt Cobra Head Lamp	46	835	$7.86	$6,559	3 130 Watt Cobra Head Lamp	835	$8.19	$6,835	$276	
4 260 Watt Cobra Head Lamp	91	495	$10.16	$5,024	4 260 Watt Cobra Head Lamp	495	$10.40	$5,143	$119	
5 50 Watt Acorn Lamp	18	113	$14.30	$1,609	5 50 Watt Acorn Lamp	113	$17.05	$1,918	$309	
6 90 Watt Acorn Lamp	32	0	$14.95	$0	6 90 Watt Acorn Lamp	0	$16.47	$0	$0	
7 50 Watt Colonial Lamp	18	0	$8.18	$0	7 50 Watt Colonial Lamp	0	$9.58	$0	$0	
8 90 Watt Colonial Lamp	32	300	$11.60	$3,480	8 90 Watt Colonial Lamp	300	$11.51	$3,453	-$27	
		5,650		$41,350		5,650		$44,492	$3,142	7.6%
Miscellaneous Charges					Miscellaneous Charges					
9 Pole Charge		0	$7.45	$0	9 Pole Charge	0	$8.73	$0	$0	0.0%
		5,650						$44,492		
NGC per kWh Charges					NGC per kWh Charges					
10 Summer kWh		59,022	$0.000107	$6	10 Summer kWh	59,022	$0.000107	$6	$0	0.0%
11 Winter kWh		136,259	$0.000107	$15	11 Winter kWh	136,259	$0.000107	$15	$0	0.0%
12 Total NGC Charges		195,281		$21	12 Total NGC Charges	195,281		$21	$0	0.0%
SBC per kWh Charges					SBC per kWh Charges					
13 All kWh		195,281	$0.006577	$1,284	13 All kWh	195,281	$0.006577	$1,284	$0	0.0%
Distribution per kWh Charges					Distribution per kWh Charges					
14 All kWh		195,281	$0.043172	$8,431	14 All kWh	195,281	$0.050606	$9,882	$1,451	
15 Total Distribition kWh Charges		195,281		$8,431	15 Total Distribition kWh Charges	195,281		$9,882	$1,451	17.2%
BGS per kWh Charges					BGS per kWh Charges					
16 Summer kWh		59,022	$0.052138	$3,077	16 Summer kWh	59,022	$0.052138	$3,077	$0	0.0%
17 Winter kWh		136,259	$0.053545	$7,296	17 Winter kWh	136,259	$0.053545	$7,296	$0	0.0%
18 Total BGS Charges		195,281		$10,373	18 Total BGS Charges	195,281		$10,373	$0	0.0%
Transmission per kWh Charges					Transmission per kWh Charges					
19 All kWh		195,281	$0.000000	$0	19 All kWh	195,281	$0.000000	$0	$0	0.0%
System Control Charges					System Control Charges					
20 All kWh		195,281	$0.004000	$781	20 All kWh	195,281	$0.004000	$781	$0	0.0%
RGGI Recovery Charges					RGGI Recovery Charges					
21 All kWh		195,281	$0.000000	$0	21 All kWh	195,281	$0.000000	$0	$0	0.0%
Tax Act djustment					Tax Act djustment					
22 All kWh		195,281	-$0.001470	-$287	22 All kWh	195,281	-$0.001470	-$287	$0	0.0%
23 Total Charges		195,281		$61,953	23 Total Charges	195,281		$66,546	$4,593	7.4%

{1} Rates effective 2/1/2020
{2} Proposed rates effective TBD

Jersey Central Power & Light Company

Summary - Customer Impact Analysis

Based on 2019/2020 6+6 Weather Normalized Billing Determinants (Includes 6.625% SUT)

Revenue at Proposed Rates Effective TBD

Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	TAA	BGS	Total
RS	$725,544	$411,666,801	$118,100,569	$63,603,079	$38,680,612	$0	-$2,811,486	$711,703,726	$1,341,668,845
RT/RGT	$16,921	$9,008,820	$2,754,274	$1,483,314	$902,087	$0	-$64,933	$17,652,119	$31,752,602
GS	$758,074	$257,071,824	$86,593,431	$46,634,905	$28,361,310	$0	-$1,822,040	$534,576,507	$952,174,011
GST	$60,299	$16,168,595	$6,887,806	$3,709,429	$2,255,913	$0	-$112,663	$35,219,016	$64,188,395
GP	$188,658	$35,431,208	$14,720,495	$12,138,134	$7,381,882	$0	-$266,544	$98,823,765	$168,417,598
GT	$197,456	$26,526,691	$13,265,772	$14,510,517	$8,824,662	$0	-$192,425	$109,764,979	$172,897,652
Lighting	$13,190	$22,270,984	$0	$811,293	$493,393	$0	-$181,276	$6,546,658	$29,954,242
Total	$1,960,142	$778,144,923	$242,322,347	$142,890,671	$86,899,859	$0	-$5,451,367	$1,514,286,770	$2,761,053,345

Change in Revenue from Current Rates to Proposed Rates Effective TBD

Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	TAA	BGS	Total
RS	$0	$109,335,678	$0	$0	$0	$0	$0	$0	$109,335,678
RT/RGT	$0	$2,218,276	$0	$0	$0	$0	$0	$0	$2,218,276
GS	$0	$65,631,066	$0	$0	$0	$0	$0	$0	$65,631,066
GST	$0	$4,303,363	$0	$0	$0	$0	$0	$0	$4,303,363
GP	$0	$8,357,718	$0	$0	$0	$0	$0	$0	$8,357,718
GT	$0	$6,253,763	$0	$0	$0	$0	$0	$0	$6,253,763
Lighting	$0	$3,257,614	$0	$0	$0	$0	$0	$0	$3,257,614
Total	$0	$199,357,478	$0	$0	$0	$0	$0	$0	$199,357,478

Percentage Change in Revenue from Current Rates to Proposed Rates Effective TBD

Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	SRC	BGS	Total
RS	0.0%	8.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.9%
RT/RGT	0.0%	7.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.5%
GS	0.0%	7.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.4%
GST	0.0%	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.2%
GP	0.0%	5.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.2%
GT	0.0%	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%
Lighting	0.0%	12.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.2%
Total	0.0%	7.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.8%

Jersey Central Power & Light Company

Residential Service (RS) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh) (a)	Current Winter Total Full Service Charges (b)	Proposed Winter Total Full Service Charges (c)	Change in Total Winter Full Service Charges (d) = (c) - (b)	Percentage Change in Total Winter Full Service Charges (e) = (d) / (b)	Current Summer Total Full Service Charges (f)	Proposed Summer Total Full Service Charges (g)	Change in Total Summer Full Service Charges (h) = (g) - (f)	Percentage Change in Total Summer Full Service Charges (i) = (h) / (f)	Current Annual Total Full Service Charges {1} (j)	Proposed Annual Total Full Service Charges {1} (k)	Change in Total Annual Full Service Charges (l) = (k) - (j)	Percentage Change in Total Annual Full Service Charges (m) = (l) / (j)
100	$15.69	$17.87	$2.18	13.9%	$13.86	$15.71	$1.85	13.3%	$180.96	$205.80	$24.84	13.7%
200	$28.59	$31.64	$3.05	10.7%	$24.94	$27.32	$2.38	9.5%	$328.48	$362.40	$33.92	10.3%
300	$41.50	$45.40	$3.90	9.4%	$36.02	$38.92	$2.90	8.1%	$476.08	$518.88	$42.80	9.0%
400	$54.40	$59.17	$4.77	8.8%	$47.10	$50.53	$3.43	7.3%	$623.60	$675.48	$51.88	8.3%
500	$67.31	$72.93	$5.62	8.3%	$58.18	$62.13	$3.95	6.8%	$771.20	$831.96	$60.76	7.9%
600	$80.21	$86.70	$6.49	8.1%	$69.26	$73.74	$4.48	6.5%	$918.72	$988.56	$69.84	7.6%
665	**$88.60**	**$95.65**	**$7.05**	**8.0%**	$79.96	$85.79	$5.83	7.3%	$1,028.64	$1,108.36	$79.72	7.8%
700	$93.12	$100.46	$7.34	7.9%	$85.72	$92.28	$6.56	7.7%	$1,087.84	$1,172.80	$84.96	7.8%
800	$106.02	$114.23	$8.21	7.7%	$102.19	$110.82	$8.63	8.4%	$1,256.92	$1,357.12	$100.20	8.0%
900	$118.93	$127.99	$9.06	7.6%	$118.65	$129.36	$10.71	9.0%	$1,426.04	$1,541.36	$115.32	8.1%
967	$127.57	$137.21	$9.64	7.6%	**$129.68**	**$141.78**	**$12.10**	**9.3%**	$1,539.28	$1,664.80	$125.52	8.2%
1,000	$131.83	$141.76	$9.93	7.5%	$135.12	$147.90	$12.78	9.5%	$1,595.12	$1,725.68	$130.56	8.2%
1,100	$144.74	$155.52	$10.78	7.4%	$151.58	$166.44	$14.86	9.8%	$1,764.24	$1,909.92	$145.68	8.3%
1,200	$157.64	$169.29	$11.65	7.4%	$168.05	$184.98	$16.93	10.1%	$1,933.32	$2,094.24	$160.92	8.3%
1,300	$170.55	$183.05	$12.50	7.3%	$184.51	$203.52	$19.01	10.3%	$2,102.44	$2,278.48	$176.04	8.4%
1,400	$183.45	$196.82	$13.37	7.3%	$200.98	$222.06	$21.08	10.5%	$2,271.52	$2,462.80	$191.28	8.4%
1,500	$196.36	$210.58	$14.22	7.2%	$217.45	$240.60	$23.15	10.6%	$2,440.68	$2,647.04	$206.36	8.5%
1,600	$209.26	$224.35	$15.09	7.2%	$233.91	$259.14	$25.23	10.8%	$2,609.72	$2,831.36	$221.64	8.5%
1,700	$222.17	$238.11	$15.94	7.2%	$250.38	$277.68	$27.30	10.9%	$2,778.88	$3,015.60	$236.72	8.5%
1,800	$235.07	$251.87	$16.80	7.1%	$266.84	$296.22	$29.38	11.0%	$2,947.92	$3,199.84	$251.92	8.5%
1,900	$247.98	$265.64	$17.66	7.1%	$283.31	$314.76	$31.45	11.1%	$3,117.08	$3,384.16	$267.08	8.6%
2,000	$260.88	$279.40	$18.52	7.1%	$299.77	$333.30	$33.53	11.2%	$3,286.12	$3,568.40	$282.28	8.6%
2,100	$273.79	$293.17	$19.38	7.1%	$316.24	$351.84	$35.60	11.3%	$3,455.28	$3,752.72	$297.44	8.6%
2,200	$286.69	$306.93	$20.24	7.1%	$332.70	$370.38	$37.68	11.3%	$3,624.32	$3,936.96	$312.64	8.6%
2,300	$299.60	$320.70	$21.10	7.0%	$349.17	$388.92	$39.75	11.4%	$3,793.48	$4,121.28	$327.80	8.6%
2,400	$312.50	$334.46	$21.96	7.0%	$365.63	$407.46	$41.83	11.4%	$3,962.52	$4,305.52	$343.00	8.7%
2,500	$325.41	$348.23	$22.82	7.0%	$382.10	$426.00	$43.90	11.5%	$4,131.68	$4,489.84	$358.16	8.7%
2,600	$338.31	$361.99	$23.68	7.0%	$398.56	$444.55	$45.99	11.5%	$4,300.72	$4,674.12	$373.40	8.7%
2,700	$351.22	$375.76	$24.54	7.0%	$415.03	$463.09	$48.06	11.6%	$4,469.88	$4,858.44	$388.56	8.7%
2,800	$364.12	$389.52	$25.40	7.0%	$431.50	$481.63	$50.13	11.6%	$4,638.96	$5,042.68	$403.72	8.7%
2,900	$377.03	$403.29	$26.26	7.0%	$447.96	$500.17	$52.21	11.7%	$4,808.08	$5,227.00	$418.92	8.7%
3,000	$389.93	$417.05	$27.12	7.0%	$464.43	$518.71	$54.28	11.7%	$4,977.16	$5,411.24	$434.08	8.7%
3,100	$402.84	$430.82	$27.98	6.9%	$480.89	$537.25	$56.36	11.7%	$5,146.28	$5,595.56	$449.28	8.7%
3,200	$415.74	$444.58	$28.84	6.9%	$497.36	$555.79	$58.43	11.7%	$5,315.36	$5,779.80	$464.44	8.7%
3,300	$428.65	$458.35	$29.70	6.9%	$513.82	$574.33	$60.51	11.8%	$5,484.48	$5,964.12	$479.64	8.7%
3,400	$441.55	$472.11	$30.56	6.9%	$530.29	$592.87	$62.58	11.8%	$5,653.56	$6,148.36	$494.80	8.8%
3,500	$454.46	$485.87	$31.41	6.9%	$546.75	$611.41	$64.66	11.8%	$5,822.68	$6,332.60	$509.92	8.8%
3,600	$467.36	$499.64	$32.28	6.9%	$563.22	$629.95	$66.73	11.8%	$5,991.76	$6,516.92	$525.16	8.8%
3,700	$480.27	$513.40	$33.13	6.9%	$579.68	$648.49	$68.81	11.9%	$6,160.88	$6,701.16	$540.28	8.8%
3,800	$493.17	$527.17	$34.00	6.9%	$596.15	$667.03	$70.88	11.9%	$6,329.96	$6,885.48	$555.52	8.8%
3,900	$506.08	$540.93	$34.85	6.9%	$612.61	$685.57	$72.96	11.9%	$6,499.08	$7,069.72	$570.64	8.8%
4,000	$518.98	$554.70	$35.72	6.9%	$629.08	$704.11	$75.03	11.9%	$6,668.16	$7,254.04	$585.88	8.8%
4,100	$531.89	$568.46	$36.57	6.9%	$645.55	$722.65	$77.10	11.9%	$6,837.32	$7,438.28	$600.96	8.8%
4,200	$544.79	$582.23	$37.44	6.9%	$662.01	$741.19	$79.18	12.0%	$7,006.36	$7,622.60	$616.24	8.8%
4,300	$557.70	$595.99	$38.29	6.9%	$678.48	$759.73	$81.25	12.0%	$7,175.52	$7,806.84	$631.32	8.8%
4,400	$570.60	$609.76	$39.16	6.9%	$694.94	$778.27	$83.33	12.0%	$7,344.56	$7,991.16	$646.60	8.8%
4,500	$583.51	$623.52	$40.01	6.9%	$711.41	$796.81	$85.40	12.0%	$7,513.72	$8,175.40	$661.68	8.8%
4,600	$596.41	$637.29	$40.88	6.9%	$727.87	$815.36	$87.49	12.0%	$7,682.76	$8,359.76	$677.00	8.8%
4,700	$609.32	$651.05	$41.73	6.8%	$744.34	$833.90	$89.56	12.0%	$7,851.92	$8,544.00	$692.08	8.8%
4,800	$622.22	$664.82	$42.60	6.8%	$760.80	$852.44	$91.64	12.0%	$8,020.96	$8,728.32	$707.36	8.8%
4,900	$635.13	$678.58	$43.45	6.8%	$777.27	$870.98	$93.71	12.1%	$8,190.12	$8,912.56	$722.44	8.8%
5,000	$648.04	$692.35	$44.31	6.8%	$793.73	$889.52	$95.79	12.1%	$8,359.24	$9,096.88	$737.64	8.8%

Average Winter Usage **Average Summer Usage**

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

Residential Time-of-Day Service (RT) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh)	Current Winter Total Full Service Charges	Proposed Winter Total Full Service Charges	Change in Total Winter Full Service Charges	Percentage Change in Total Winter Full Service Charges	Current Summer Total Full Service Charges	Proposed Summer Total Full Service Charges	Change in Total Summer Full Service Charges	Percentage Change in Total Summer Full Service Charges	Current Annual Total Full Service Charges {1}	Proposed Annual Total Full Service Charges {1}	Change in Total Annual Full Service Charges	Percentage Change in Total Annual Full Service Charges
(a)	(b)	(c)	(d) = (c) - (b)	(e) = (d) / (b)	(f)	(g)	(h) = (g) - (f)	(i) = (h) / (f)	(j)	(k)	(l) = (k) - (j)	(m) = (l) / (j)
100	$18.48	$22.68	$4.20	22.7%	$19.27	$23.62	$4.35	22.6%	$224.92	$275.92	$51.00	22.7%
200	$31.77	$36.66	$4.89	15.4%	$33.36	$38.55	$5.19	15.6%	$387.60	$447.48	$59.88	15.4%
300	$45.07	$50.65	$5.58	12.4%	$47.44	$53.47	$6.03	12.7%	$550.32	$619.08	$68.76	12.5%
400	$58.36	$64.63	$6.27	10.7%	$61.52	$68.40	$6.88	11.2%	$712.96	$790.64	$77.68	10.9%
500	$71.65	$78.62	$6.97	9.7%	$75.61	$83.33	$7.72	10.2%	$875.64	$962.28	$86.64	9.9%
600	$84.94	$92.61	$7.67	9.0%	$89.69	$98.26	$8.57	9.6%	$1,038.28	$1,133.92	$95.64	9.2%
700	$98.24	$106.59	$8.35	8.5%	$103.78	$113.19	$9.41	9.1%	$1,201.04	$1,305.48	$104.44	8.7%
800	$111.53	$120.58	$9.05	8.1%	$117.86	$128.12	$10.26	8.7%	$1,363.68	$1,477.12	$113.44	8.3%
900	$124.82	$134.56	$9.74	7.8%	$131.94	$143.04	$11.10	8.4%	$1,526.32	$1,648.64	$122.32	8.0%
1,000	$138.11	$148.55	$10.44	7.6%	$146.03	$157.97	$11.94	8.2%	$1,689.00	$1,820.28	$131.28	7.8%
1,026	$141.52	$152.13	$10.61	7.5%	**$149.63**	**$161.79**	**$12.16**	**8.1%**	$1,730.68	$1,864.20	$133.52	7.7%
1,170	**$160.74**	**$172.35**	**$11.61**	**7.2%**	$170.00	$183.38	$13.38	7.9%	$1,965.92	$2,112.32	$146.40	7.4%
1,100	$151.41	$162.54	$11.13	7.4%	$160.11	$172.90	$12.79	8.0%	$1,851.72	$1,991.92	$140.20	7.6%
1,200	$164.70	$176.52	$11.82	7.2%	$174.19	$187.83	$13.64	7.8%	$2,014.36	$2,163.48	$149.12	7.4%
1,300	$177.99	$190.51	$12.52	7.0%	$188.28	$202.76	$14.48	7.7%	$2,177.04	$2,335.12	$158.08	7.3%
1,400	$191.28	$204.49	$13.21	6.9%	$202.36	$217.69	$15.33	7.6%	$2,339.68	$2,506.68	$167.00	7.1%
1,500	$204.58	$218.48	$13.90	6.8%	$216.45	$232.61	$16.16	7.5%	$2,502.44	$2,678.28	$175.84	7.0%
1,600	$217.87	$232.47	$14.60	6.7%	$230.53	$247.54	$17.01	7.4%	$2,665.08	$2,849.92	$184.84	6.9%
1,700	$231.16	$246.45	$15.29	6.6%	$244.61	$262.47	$17.86	7.3%	$2,827.72	$3,021.48	$193.76	6.9%
1,800	$244.45	$260.44	$15.99	6.5%	$258.70	$277.40	$18.70	7.2%	$2,990.40	$3,193.12	$202.72	6.8%
1,900	$257.74	$274.42	$16.68	6.5%	$272.78	$292.33	$19.55	7.2%	$3,153.04	$3,364.68	$211.64	6.7%
2,000	$271.04	$288.41	$17.37	6.4%	$286.86	$307.25	$20.39	7.1%	$3,315.76	$3,536.28	$220.52	6.7%
2,100	$284.33	$302.40	$18.07	6.4%	$300.95	$322.18	$21.23	7.1%	$3,478.44	$3,707.92	$229.48	6.6%
2,200	$297.62	$316.38	$18.76	6.3%	$315.03	$337.11	$22.08	7.0%	$3,641.08	$3,879.48	$238.40	6.5%
2,300	$310.91	$330.37	$19.46	6.3%	$329.11	$352.04	$22.93	7.0%	$3,803.72	$4,051.12	$247.40	6.5%
2,400	$324.21	$344.35	$20.14	6.2%	$343.20	$366.97	$23.77	6.9%	$3,966.48	$4,222.68	$256.20	6.5%
2,500	$337.50	$358.34	$20.84	6.2%	$357.28	$381.90	$24.62	6.9%	$4,129.12	$4,394.32	$265.20	6.4%
2,600	$350.79	$372.33	$21.54	6.1%	$371.37	$396.82	$25.45	6.9%	$4,291.80	$4,565.92	$274.12	6.4%
2,700	$364.08	$386.31	$22.23	6.1%	$385.45	$411.75	$26.30	6.8%	$4,454.44	$4,737.48	$283.04	6.4%
2,800	$377.38	$400.30	$22.92	6.1%	$399.53	$426.68	$27.15	6.8%	$4,617.16	$4,909.12	$291.96	6.3%
2,900	$390.67	$414.28	$23.61	6.0%	$413.62	$441.61	$27.99	6.8%	$4,779.84	$5,080.68	$300.84	6.3%
3,000	$403.96	$428.27	$24.31	6.0%	$427.70	$456.54	$28.84	6.7%	$4,942.48	$5,252.32	$309.84	6.3%
3,100	$417.25	$442.26	$25.01	6.0%	$441.78	$471.47	$29.69	6.7%	$5,105.12	$5,423.96	$318.84	6.2%
3,200	$430.55	$456.24	$25.69	6.0%	$455.87	$486.39	$30.52	6.7%	$5,267.88	$5,595.48	$327.60	6.2%
3,300	$443.84	$470.23	$26.39	5.9%	$469.95	$501.32	$31.37	6.7%	$5,430.52	$5,767.12	$336.60	6.2%
3,400	$457.13	$484.21	$27.08	5.9%	$484.04	$516.25	$32.21	6.7%	$5,593.20	$5,938.68	$345.48	6.2%
3,500	$470.42	$498.20	$27.78	5.9%	$498.12	$531.18	$33.06	6.6%	$5,755.84	$6,110.32	$354.48	6.2%
3,600	$483.71	$512.19	$28.48	5.9%	$512.20	$546.11	$33.91	6.6%	$5,918.48	$6,281.96	$363.48	6.1%
3,700	$497.01	$526.17	$29.16	5.9%	$526.29	$561.03	$34.74	6.6%	$6,081.24	$6,453.48	$372.24	6.1%
3,800	$510.30	$540.16	$29.86	5.9%	$540.37	$575.96	$35.59	6.6%	$6,243.88	$6,625.12	$381.24	6.1%
3,900	$523.59	$554.14	$30.55	5.8%	$554.45	$590.89	$36.44	6.6%	$6,406.52	$6,796.68	$390.16	6.1%
4,000	$536.88	$568.13	$31.25	5.8%	$568.54	$605.82	$37.28	6.6%	$6,569.20	$6,968.32	$399.12	6.1%
4,100	$550.18	$582.12	$31.94	5.8%	$582.62	$620.75	$38.13	6.5%	$6,731.92	$7,139.96	$408.04	6.1%
4,200	$563.47	$596.10	$32.63	5.8%	$596.70	$635.68	$38.98	6.5%	$6,894.56	$7,311.52	$416.96	6.0%
4,300	$576.76	$610.09	$33.33	5.8%	$610.79	$650.60	$39.81	6.5%	$7,057.24	$7,483.12	$425.88	6.0%
4,400	$590.05	$624.07	$34.02	5.8%	$624.87	$665.53	$40.66	6.5%	$7,219.88	$7,654.68	$434.80	6.0%
4,500	$603.35	$638.06	$34.71	5.8%	$638.96	$680.46	$41.50	6.5%	$7,382.64	$7,826.32	$443.68	6.0%
4,600	$616.64	$652.05	$35.41	5.7%	$653.04	$695.39	$42.35	6.5%	$7,545.28	$7,997.96	$452.68	6.0%
4,700	$629.93	$666.03	$36.10	5.7%	$667.12	$710.32	$43.20	6.5%	$7,707.92	$8,169.52	$461.60	6.0%
4,800	$643.22	$680.02	$36.80	5.7%	$681.21	$725.25	$44.04	6.5%	$7,870.60	$8,341.16	$470.56	6.0%
4,900	$656.52	$694.00	$37.48	5.7%	$695.29	$740.17	$44.88	6.5%	$8,033.32	$8,512.68	$479.36	6.0%
5,000	$669.81	$707.99	$38.18	5.7%	$709.37	$755.10	$45.73	6.4%	$8,195.96	$8,684.32	$488.36	6.0%

Average Winter Usage   **Average Summer Usage**

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

Residential Geothermal & Heat Pump Service (RGT) - Detailed Customer Impact Analysis
Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh) (a)	Current Winter Total Full Service Charges (b)	Proposed Winter Total Full Service Charges (c)	Change in Total Winter Full Service Charges (d) = (c) - (b)	Percentage Change in Total Winter Full Service Charges (e) = (d) / (b)	Current Summer Total Full Service Charges (f)	Proposed Summer Total Full Service Charges (g)	Change in Total Summer Full Service Charges (h) = (g) - (f)	Percentage Change in Total Summer Full Service Charges (i) = (h) / (f)	Current Annual Total Full Service Charges {1} (j)	Proposed Annual Total Full Service Charges {1} (k)	Change in Total Annual Full Service Charges (l) = (k) - (j)	Percentage Change in Total Annual Full Service Charges (m) = (l) / (j)
100	$18.10	$22.46	$4.36	24.1%	$19.33	$23.68	$4.35	22.5%	$222.12	$274.40	$52.28	23.5%
200	$31.00	$36.22	$5.22	16.8%	$33.47	$38.66	$5.19	15.5%	$381.88	$444.40	$62.52	16.4%
300	$43.91	$49.99	$6.08	13.8%	$47.61	$53.65	$6.04	12.7%	$541.72	$614.52	$72.80	13.4%
400	$56.81	$63.75	$6.94	12.2%	$61.75	$68.64	$6.89	11.2%	$701.48	$784.56	$83.08	11.8%
500	$69.72	$77.52	$7.80	11.2%	$75.89	$83.63	$7.74	10.2%	$861.32	$954.68	$93.36	10.8%
600	$82.62	$91.28	$8.66	10.5%	$90.03	$98.61	$8.58	9.5%	$1,021.08	$1,124.68	$103.60	10.1%
700	$95.53	$105.05	$9.52	10.0%	$104.17	$113.60	$9.43	9.1%	$1,180.92	$1,294.80	$113.88	9.6%
800	$108.43	$118.81	$10.38	9.6%	$118.31	$128.59	$10.28	8.7%	$1,340.68	$1,464.84	$124.16	9.3%
900	$121.34	$132.58	$11.24	9.3%	$132.45	$143.58	$11.13	8.4%	$1,500.52	$1,634.96	$134.44	9.0%
1,000	$134.24	$146.34	$12.10	9.0%	$146.59	$158.56	$11.97	8.2%	$1,660.28	$1,804.96	$144.68	8.7%
1,100	$147.15	$160.11	$12.96	8.8%	$160.73	$173.55	$12.82	8.0%	$1,820.12	$1,975.08	$154.96	8.5%
1,200	$160.05	$173.87	$13.82	8.6%	$174.86	$188.54	$13.68	7.8%	$1,979.84	$2,145.12	$165.28	8.3%
1,300	$172.96	$187.64	$14.68	8.5%	$189.00	$203.53	$14.53	7.7%	$2,139.68	$2,315.24	$175.56	8.2%
1,400	$185.87	$201.40	$15.53	8.4%	$203.14	$218.51	$15.37	7.6%	$2,299.52	$2,485.24	$185.72	8.1%
1,500	$198.77	$215.17	$16.40	8.3%	$217.28	$233.50	$16.22	7.5%	$2,459.28	$2,655.36	$196.08	8.0%
1,600	$211.68	$228.93	$17.25	8.1%	$231.42	$248.49	$17.07	7.4%	$2,619.12	$2,825.40	$206.28	7.9%
1,700	$224.58	$242.70	$18.12	8.1%	$245.56	$263.48	$17.92	7.3%	$2,778.88	$2,995.52	$216.64	7.8%
1,800	$237.49	$256.46	$18.97	8.0%	$259.70	$278.46	$18.76	7.2%	$2,938.72	$3,165.52	$226.80	7.7%
1,900	$250.39	$270.23	$19.84	7.9%	$273.84	$293.45	$19.61	7.2%	$3,098.48	$3,335.64	$237.16	7.7%
1,963	$258.46	$278.83	$20.37	7.9%	**$282.68**	**$302.82**	**$20.14**	**7.1%**	$3,198.40	$3,441.92	$243.52	7.6%
2,000	$263.30	$283.99	$20.69	7.9%	$287.98	$308.44	$20.46	7.1%	$3,258.32	$3,505.68	$247.36	7.6%
2,100	$276.20	$297.76	$21.56	7.8%	$302.12	$323.43	$21.31	7.1%	$3,418.08	$3,675.80	$257.72	7.5%
2,200	$289.11	$311.52	$22.41	7.8%	$316.26	$338.41	$22.15	7.0%	$3,577.92	$3,845.80	$267.88	7.5%
2,209	**$290.21**	**$312.69**	**$22.48**	**7.7%**	$317.46	$339.69	$22.23	7.0%	$3,591.52	$3,860.28	$268.76	7.5%
2,300	$302.01	$325.29	$23.28	7.7%	$330.40	$353.40	$23.00	7.0%	$3,737.68	$4,015.92	$278.24	7.4%
2,400	$314.92	$339.05	$24.13	7.7%	$344.54	$368.39	$23.85	6.9%	$3,897.52	$4,185.96	$288.44	7.4%
2,500	$327.83	$352.82	$24.99	7.6%	$358.68	$383.38	$24.70	6.9%	$4,057.36	$4,356.08	$298.72	7.4%
2,600	$340.73	$366.58	$25.85	7.6%	$372.82	$398.36	$25.54	6.9%	$4,217.12	$4,526.08	$308.96	7.3%
2,700	$353.64	$380.35	$26.71	7.6%	$386.96	$413.35	$26.39	6.8%	$4,376.96	$4,696.20	$319.24	7.3%
2,800	$366.54	$394.11	$27.57	7.5%	$401.10	$428.34	$27.24	6.8%	$4,536.72	$4,866.24	$329.52	7.3%
2,900	$379.45	$407.88	$28.43	7.5%	$415.24	$443.32	$28.08	6.8%	$4,696.56	$5,036.32	$339.76	7.2%
3,000	$392.35	$421.64	$29.29	7.5%	$429.38	$458.31	$28.93	6.7%	$4,856.32	$5,206.36	$350.04	7.2%
3,100	$405.26	$435.41	$30.15	7.4%	$443.52	$473.30	$29.78	6.7%	$5,016.16	$5,376.48	$360.32	7.2%
3,200	$418.16	$449.17	$31.01	7.4%	$457.66	$488.29	$30.63	6.7%	$5,175.92	$5,546.52	$370.60	7.2%
3,300	$431.07	$462.94	$31.87	7.4%	$471.80	$503.27	$31.47	6.7%	$5,335.76	$5,716.60	$380.84	7.1%
3,400	$443.97	$476.70	$32.73	7.4%	$485.94	$518.26	$32.32	6.7%	$5,495.52	$5,886.64	$391.12	7.1%
3,500	$456.88	$490.47	$33.59	7.4%	$500.07	$533.25	$33.18	6.6%	$5,655.32	$6,056.76	$401.44	7.1%
3,600	$469.78	$504.23	$34.45	7.3%	$514.21	$548.24	$34.03	6.6%	$5,815.08	$6,226.80	$411.72	7.1%
3,700	$482.69	$518.00	$35.31	7.3%	$528.35	$563.22	$34.87	6.6%	$5,974.92	$6,396.88	$421.96	7.1%
3,800	$495.60	$531.76	$36.16	7.3%	$542.49	$578.21	$35.72	6.6%	$6,134.76	$6,566.92	$432.16	7.0%
3,900	$508.50	$545.53	$37.03	7.3%	$556.63	$593.20	$36.57	6.6%	$6,294.52	$6,737.04	$442.52	7.0%
4,000	$521.41	$559.29	$37.88	7.3%	$570.77	$608.19	$37.42	6.6%	$6,454.36	$6,907.08	$452.72	7.0%
4,100	$534.31	$573.06	$38.75	7.3%	$584.91	$623.17	$38.26	6.5%	$6,614.12	$7,077.16	$463.04	7.0%
4,200	$547.22	$586.82	$39.60	7.2%	$599.05	$638.16	$39.11	6.5%	$6,773.96	$7,247.20	$473.24	7.0%
4,300	$560.12	$600.59	$40.47	7.2%	$613.19	$653.15	$39.96	6.5%	$6,933.72	$7,417.32	$483.60	7.0%
4,400	$573.03	$614.35	$41.32	7.2%	$627.33	$668.14	$40.81	6.5%	$7,093.56	$7,587.36	$493.80	7.0%
4,500	$585.93	$628.12	$42.19	7.2%	$641.47	$683.12	$41.65	6.5%	$7,253.32	$7,757.44	$504.12	7.0%
4,600	$598.84	$641.88	$43.04	7.2%	$655.61	$698.11	$42.50	6.5%	$7,413.16	$7,927.48	$514.32	6.9%
4,700	$611.74	$655.65	$43.91	7.2%	$669.75	$713.10	$43.35	6.5%	$7,572.92	$8,097.60	$524.68	6.9%
4,800	$624.65	$669.41	$44.76	7.2%	$683.89	$728.09	$44.20	6.5%	$7,732.76	$8,267.64	$534.88	6.9%
4,900	$637.55	$683.18	$45.63	7.2%	$698.03	$743.07	$45.04	6.5%	$7,892.52	$8,437.72	$545.20	6.9%
5,000	$650.46	$696.94	$46.48	7.1%	$712.17	$758.06	$45.89	6.4%	$8,052.36	$8,607.76	$555.40	6.9%

Average Winter Usage **Average Summer Usage**

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

General Service Secondary (GS) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh) (a)	Current Winter Total Full Service Charges (b)	Proposed Winter Total Full Service Charges (c)	Change in Total Winter Full Service Charges (d) = (c) - (b)	Percentage Change in Total Winter Full Service Charges (e) = (d) / (b)	Current Summer Total Full Service Charges (f)	Proposed Summer Total Full Service Charges (g)	Change in Total Summer Full Service Charges (h) = (g) - (f)	Percentage Change in Total Summer Full Service Charges (i) = (h) / (f)	Current Annual Total Full Service Charges {1} (j)	Proposed Annual Total Full Service Charges {1} (k)	Change in Total Annual Full Service Charges (l) = (k) - (j)	Percentage Change in Total Annual Full Service Charges (m) = (l) / (j)
50	$11.07	$13.00	$1.93	17.4%	$11.29	$13.28	$1.99	17.6%	$133.72	$157.12	$23.40	17.5%
100	$19.04	$21.72	$2.68	14.1%	$19.48	$22.29	$2.81	14.4%	$230.24	$262.92	$32.68	14.2%
200	$34.98	$39.17	$4.19	12.0%	$35.87	$40.30	$4.43	12.4%	$423.32	$474.56	$51.24	12.1%
300	$50.92	$56.61	$5.69	11.2%	$52.25	$58.31	$6.06	11.6%	$616.36	$686.12	$69.76	11.3%
400	$66.86	$74.06	$7.20	10.8%	$68.63	$76.31	$7.68	11.2%	$809.40	$897.72	$88.32	10.9%
500	$82.80	$91.50	$8.70	10.5%	$85.01	$94.32	$9.31	11.0%	$1,002.44	$1,109.28	$106.84	10.7%
600	$98.74	$108.94	$10.20	10.3%	$101.40	$112.33	$10.93	10.8%	$1,195.52	$1,320.84	$125.32	10.5%
700	$114.68	$126.39	$11.71	10.2%	$117.78	$130.34	$12.56	10.7%	$1,388.56	$1,532.48	$143.92	10.4%
800	$130.62	$143.83	$13.21	10.1%	$134.16	$148.35	$14.19	10.6%	$1,581.60	$1,744.04	$162.44	10.3%
900	$146.56	$161.28	$14.72	10.0%	$150.55	$166.36	$15.81	10.5%	$1,774.68	$1,955.68	$181.00	10.2%
1,000	$162.50	$178.72	$16.22	10.0%	$166.93	$184.37	$17.44	10.4%	$1,967.72	$2,167.24	$199.52	10.1%
1,100	$173.43	$189.78	$16.35	9.4%	$177.86	$195.42	$17.56	9.9%	$2,098.88	$2,299.92	$201.04	9.6%
1,200	$184.35	$200.83	$16.48	8.9%	$188.78	$206.48	$17.70	9.4%	$2,229.92	$2,432.56	$202.64	9.1%
1,300	$195.28	$211.89	$16.61	8.5%	$199.71	$217.54	$17.83	8.9%	$2,361.08	$2,565.28	$204.20	8.6%
1,400	$206.21	$222.95	$16.74	8.1%	$210.64	$228.60	$17.96	8.5%	$2,492.24	$2,698.00	$205.76	8.3%
1,500	$217.13	$234.01	$16.88	7.8%	$221.57	$239.65	$18.08	8.2%	$2,623.32	$2,830.68	$207.36	7.9%
1,600	$228.06	$245.06	$17.00	7.5%	$232.49	$250.71	$18.22	7.8%	$2,754.44	$2,963.32	$208.88	7.6%
1,700	$238.99	$256.12	$17.13	7.2%	$243.42	$261.77	$18.35	7.5%	$2,885.60	$3,096.04	$210.44	7.3%
1,800	$249.92	$267.18	$17.26	6.9%	$254.35	$272.82	$18.47	7.3%	$3,016.76	$3,228.72	$211.96	7.0%
1,900	$260.84	$278.23	$17.39	6.7%	$265.27	$283.88	$18.61	7.0%	$3,147.80	$3,361.36	$213.56	6.8%
2,000	$271.77	$289.29	$17.52	6.4%	$276.20	$294.94	$18.74	6.8%	$3,278.96	$3,494.08	$215.12	6.6%
2,100	$282.70	$300.35	$17.65	6.2%	$287.13	$306.00	$18.87	6.6%	$3,410.12	$3,626.80	$216.68	6.4%
2,200	$293.63	$311.41	$17.78	6.1%	$298.06	$317.05	$18.99	6.4%	$3,541.28	$3,759.48	$218.20	6.2%
2,300	$304.55	$322.46	$17.91	5.9%	$308.98	$328.11	$19.13	6.2%	$3,672.32	$3,892.12	$219.80	6.0%
2,400	$315.48	$333.52	$18.04	5.7%	$319.91	$339.17	$19.26	6.0%	$3,803.48	$4,024.84	$221.36	5.8%
2,500	$326.41	$344.58	$18.17	5.6%	$330.84	$350.23	$19.39	5.9%	$3,934.64	$4,157.56	$222.92	5.7%
2,600	$339.18	$358.22	$19.04	5.6%	$341.77	$361.28	$19.51	5.7%	$4,080.52	$4,310.88	$230.36	5.6%
2,700	$352.58	$372.71	$20.13	5.7%	$354.68	$375.11	$20.43	5.8%	$4,239.36	$4,482.12	$242.76	5.7%
2,800	$365.98	$387.21	$21.23	5.8%	$368.26	$389.87	$21.61	5.9%	$4,400.88	$4,657.16	$256.28	5.8%
2,900	$379.38	$401.71	$22.33	5.9%	$381.84	$404.61	$22.77	6.0%	$4,562.40	$4,832.12	$269.72	5.9%
3,000	$392.76	$416.20	$23.44	6.0%	$395.43	$419.37	$23.94	6.1%	$4,723.80	$5,007.08	$283.28	6.0%
3,500	$459.74	$488.69	$28.95	6.3%	$462.65	$492.22	$29.57	6.4%	$5,528.52	$5,878.40	$349.88	6.3%
4,000	$526.11	$560.32	$34.21	6.5%	$529.89	$565.05	$35.16	6.6%	$6,328.44	$6,742.76	$414.32	6.5%
4,182	**$550.88**	**$587.28**	**$36.40**	**6.6%**	$554.37	$591.60	$37.23	6.7%	$6,624.52	$7,064.64	$440.12	6.6%
4,500	$593.08	$632.80	$39.72	6.7%	$597.12	$637.90	$40.78	6.8%	$7,133.12	$7,614.00	$480.88	6.7%
4,862	$641.93	$685.77	$43.84	6.8%	**$646.01**	**$690.90**	**$44.89**	**6.9%**	$7,719.48	$8,249.76	$530.28	6.9%
5,000	$660.06	$705.29	$45.23	6.9%	$664.35	$710.74	$46.39	7.0%	$7,937.88	$8,485.28	$547.40	6.9%
6,000	$794.01	$850.26	$56.25	7.1%	$798.82	$856.43	$57.61	7.2%	$9,547.36	$10,227.80	$680.44	7.1%
7,000	$927.35	$994.37	$67.02	7.2%	$933.29	$1,002.11	$68.82	7.4%	$11,151.96	$11,963.40	$811.44	7.3%
8,000	$1,061.30	$1,139.34	$78.04	7.4%	$1,068.42	$1,148.71	$80.29	7.5%	$12,764.08	$13,709.56	$945.48	7.4%
9,000	$1,195.25	$1,284.32	$89.07	7.5%	$1,202.88	$1,294.40	$91.52	7.6%	$14,373.52	$15,452.16	$1,078.64	7.5%
10,000	$1,328.59	$1,428.43	$99.84	7.5%	$1,337.36	$1,440.09	$102.73	7.7%	$15,978.16	$17,187.80	$1,209.64	7.6%
15,000	$1,997.12	$2,151.57	$154.45	7.7%	$2,010.35	$2,169.43	$159.08	7.9%	$24,018.36	$25,890.28	$1,871.92	7.8%
20,000	$2,665.65	$2,874.71	$209.06	7.8%	$2,683.35	$2,898.78	$215.43	8.0%	$32,058.60	$34,592.80	$2,534.20	7.9%
25,000	$3,334.18	$3,597.85	$263.67	7.9%	$3,356.35	$3,628.12	$271.77	8.1%	$40,098.84	$43,295.28	$3,196.44	8.0%
30,000	$4,003.33	$4,321.85	$318.52	8.0%	$4,029.35	$4,357.46	$328.11	8.1%	$48,144.04	$52,004.64	$3,860.60	8.0%
35,000	$4,671.86	$5,044.99	$373.13	8.0%	$4,702.34	$5,086.81	$384.47	8.2%	$56,184.24	$60,707.16	$4,522.92	8.1%
40,000	$5,340.40	$5,768.13	$427.73	8.0%	$5,375.34	$5,816.15	$440.81	8.2%	$64,224.56	$69,409.64	$5,185.08	8.1%
45,000	$6,008.92	$6,491.27	$482.35	8.0%	$6,048.34	$6,545.50	$497.16	8.2%	$72,264.72	$78,112.16	$5,847.44	8.1%
50,000	$6,677.46	$7,214.41	$536.95	8.0%	$6,721.34	$7,274.84	$553.50	8.2%	$80,305.04	$86,814.64	$6,509.60	8.1%

Average Winter Usage **Average Summer Usage**

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

General Service Secondary Time-of-Day (GST) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh)	Current Winter Total Full Service Charges	Proposed Winter Total Full Service Charges	Change in Total Winter Full Service Charges	Percentage Change in Total Winter Full Service Charges	Current Summer Total Full Service Charges	Proposed Summer Total Full Service Charges	Change in Total Summer Full Service Charges	Percentage Change in Total Summer Full Service Charges	Current Annual Total Full Service Charges {1}	Proposed Annual Total Full Service Charges {1}	Change in Total Annual Full Service Charges	Percentage Change in Total Annual Full Service Charges
(a)	(b)	(c)	(d) = (c) - (b)	(e) = (d) / (b)	(f)	(g)	(h) = (g) - (f)	(i) = (h) / (f)	(j)	(k)	(l) = (k) - (j)	(m) = (l) / (j)
150,000	$16,945.78	$18,104.54	$1,158.76	6.8%	$16,789.39	$18,016.45	$1,227.06	7.3%	$202,723.80	$216,902.12	$14,178.32	7.0%
160,000	$18,072.74	$19,307.66	$1,234.92	6.8%	$17,905.84	$19,213.57	$1,307.73	7.3%	$216,205.28	$231,315.56	$15,110.28	7.0%
170,000	$19,199.71	$20,510.78	$1,311.07	6.8%	$19,022.29	$20,410.69	$1,388.40	7.3%	$229,686.84	$245,729.00	$16,042.16	7.0%
180,000	$20,326.68	$21,713.90	$1,387.22	6.8%	$20,138.75	$21,607.82	$1,469.07	7.3%	$243,168.44	$260,142.48	$16,974.04	7.0%
190,000	$21,453.64	$22,917.02	$1,463.38	6.8%	$21,255.20	$22,804.94	$1,549.74	7.3%	$256,649.92	$274,555.92	$17,906.00	7.0%
200,000	$22,579.95	$24,119.22	$1,539.27	6.8%	$22,371.65	$24,002.06	$1,630.41	7.3%	$270,126.20	$288,962.00	$18,835.80	7.0%
210,000	$23,706.92	$25,322.33	$1,615.41	6.8%	$23,488.10	$25,199.18	$1,711.08	7.3%	$283,607.76	$303,375.36	$19,767.60	7.0%
220,000	$24,833.88	$26,525.45	$1,691.57	6.8%	$24,604.55	$26,396.30	$1,791.75	7.3%	$297,089.24	$317,788.80	$20,699.56	7.0%
230,000	$25,960.85	$27,728.57	$1,767.72	6.8%	$25,721.01	$27,593.43	$1,872.42	7.3%	$310,570.84	$332,202.28	$21,631.44	7.0%
216,665	**$24,457.84**	**$26,123.94**	**$1,666.10**	**6.8%**	$24,232.00	$25,996.77	$1,764.77	7.3%	$292,590.72	$312,978.60	$20,387.88	7.0%
240,000	$27,087.82	$28,931.69	$1,843.87	6.8%	$26,837.46	$28,790.55	$1,953.09	7.3%	$324,052.40	$346,615.72	$22,563.32	7.0%
250,000	$28,214.78	$30,134.81	$1,920.03	6.8%	$27,953.91	$29,987.67	$2,033.76	7.3%	$337,533.88	$361,029.16	$23,495.28	7.0%
260,000	$29,341.75	$31,337.92	$1,996.17	6.8%	$29,070.36	$31,184.79	$2,114.43	7.3%	$351,015.44	$375,442.52	$24,427.08	7.0%
239,071	$26,983.37	$28,820.25	$1,836.88	6.8%	**$26,733.99**	**$28,679.68**	**$1,945.69**	**7.3%**	$322,802.92	$345,280.72	$22,477.80	7.0%
270,000	$30,468.06	$32,540.12	$2,072.06	6.8%	$30,186.81	$32,381.91	$2,195.10	7.3%	$364,491.72	$389,848.60	$25,356.88	7.0%
280,000	$31,595.02	$33,743.24	$2,148.22	6.8%	$31,303.27	$33,579.04	$2,275.77	7.3%	$377,973.24	$404,262.08	$26,288.84	7.0%
290,000	$32,721.99	$34,946.36	$2,224.37	6.8%	$32,419.72	$34,776.16	$2,356.44	7.3%	$391,454.80	$418,675.52	$27,220.72	7.0%
300,000	$33,848.96	$36,149.48	$2,300.52	6.8%	$33,536.17	$35,973.28	$2,437.11	7.3%	$404,936.36	$433,088.96	$28,152.60	7.0%
310,000	$34,975.92	$37,352.60	$2,376.68	6.8%	$34,652.62	$37,170.40	$2,517.78	7.3%	$418,417.84	$447,502.40	$29,084.56	7.0%
320,000	$36,102.89	$38,555.71	$2,452.82	6.8%	$35,769.07	$38,367.52	$2,598.45	7.3%	$431,899.40	$461,915.76	$30,016.36	6.9%
330,000	$37,229.85	$39,758.83	$2,528.98	6.8%	$36,885.52	$39,564.64	$2,679.12	7.3%	$445,380.88	$476,329.20	$30,948.32	6.9%
340,000	$38,356.82	$40,961.95	$2,605.13	6.8%	$38,001.97	$40,761.76	$2,759.79	7.3%	$458,862.44	$490,742.64	$31,880.20	6.9%
350,000	$39,483.13	$42,164.15	$2,681.02	6.8%	$39,118.42	$41,958.88	$2,840.46	7.3%	$472,338.72	$505,148.72	$32,810.00	6.9%
360,000	$40,610.10	$43,367.27	$2,757.17	6.8%	$40,234.87	$43,156.00	$2,921.13	7.3%	$485,820.28	$519,562.16	$33,741.88	6.9%
370,000	$41,737.06	$44,570.39	$2,833.33	6.8%	$41,351.32	$44,353.12	$3,001.80	7.3%	$499,301.76	$533,975.60	$34,673.84	6.9%
380,000	$42,864.03	$45,773.50	$2,909.47	6.8%	$42,467.78	$45,550.25	$3,082.47	7.3%	$512,783.36	$548,389.00	$35,605.64	6.9%
390,000	$43,990.99	$46,976.62	$2,985.63	6.8%	$43,584.23	$46,747.37	$3,163.14	7.3%	$526,264.84	$562,802.44	$36,537.60	6.9%
400,000	$45,117.96	$48,179.74	$3,061.78	6.8%	$44,700.68	$47,944.49	$3,243.81	7.3%	$539,746.40	$577,215.88	$37,469.48	6.9%
410,000	$46,244.93	$49,382.86	$3,137.93	6.8%	$45,817.13	$49,141.61	$3,324.48	7.3%	$553,227.96	$591,629.32	$38,401.36	6.9%
420,000	$47,371.89	$50,585.98	$3,214.09	6.8%	$46,933.58	$50,338.73	$3,405.15	7.3%	$566,709.44	$606,042.76	$39,333.32	6.9%
430,000	$48,498.20	$51,788.18	$3,289.98	6.8%	$48,050.04	$51,535.86	$3,485.82	7.3%	$580,185.76	$620,448.88	$40,263.12	6.9%
440,000	$49,625.16	$52,991.28	$3,366.12	6.8%	$49,166.49	$52,732.98	$3,566.49	7.3%	$593,667.24	$634,862.16	$41,194.92	6.9%
450,000	$50,752.12	$54,194.40	$3,442.28	6.8%	$50,282.94	$53,930.10	$3,647.16	7.3%	$607,148.72	$649,275.60	$42,126.88	6.9%
460,000	$51,879.09	$55,397.52	$3,518.43	6.8%	$51,399.39	$55,127.22	$3,727.83	7.3%	$620,630.28	$663,689.04	$43,058.76	6.9%
470,000	$53,006.06	$56,600.64	$3,594.58	6.8%	$52,515.84	$56,324.34	$3,808.50	7.3%	$634,111.84	$678,102.48	$43,990.64	6.9%
480,000	$54,133.02	$57,803.76	$3,670.74	6.8%	$53,632.30	$57,521.47	$3,889.17	7.3%	$647,593.36	$692,515.96	$44,922.60	6.9%
490,000	$55,259.99	$59,006.87	$3,746.88	6.8%	$54,748.75	$58,718.59	$3,969.84	7.3%	$661,074.92	$706,929.32	$45,854.40	6.9%
500,000	$56,386.95	$60,209.99	$3,823.04	6.8%	$55,865.20	$59,915.71	$4,050.51	7.3%	$674,556.40	$721,342.76	$46,786.36	6.9%
510,000	$57,513.26	$61,412.19	$3,898.93	6.8%	$56,981.65	$61,112.83	$4,131.18	7.3%	$688,032.68	$735,748.84	$47,716.16	6.9%
520,000	$58,640.23	$62,615.31	$3,975.08	6.8%	$58,098.10	$62,309.95	$4,211.85	7.2%	$701,514.24	$750,162.28	$48,648.04	6.9%
530,000	$59,767.20	$63,818.43	$4,051.23	6.8%	$59,214.56	$63,507.08	$4,292.52	7.2%	$714,995.84	$764,575.76	$49,579.92	6.9%
540,000	$60,894.16	$65,021.55	$4,127.39	6.8%	$60,331.01	$64,704.20	$4,373.19	7.2%	$728,477.32	$778,989.20	$50,511.88	6.9%
550,000	$62,021.13	$66,224.66	$4,203.53	6.8%	$61,447.46	$65,901.32	$4,453.86	7.2%	$741,958.88	$793,402.56	$51,443.68	6.9%
560,000	$63,148.09	$67,427.78	$4,279.69	6.8%	$62,563.91	$67,098.44	$4,534.53	7.2%	$755,440.36	$807,816.00	$52,375.64	6.9%
570,000	$64,275.06	$68,630.90	$4,355.84	6.8%	$63,680.36	$68,295.56	$4,615.20	7.2%	$768,921.92	$822,229.44	$53,307.52	6.9%
580,000	$65,401.37	$69,833.10	$4,431.73	6.8%	$64,796.82	$69,492.69	$4,695.87	7.2%	$782,398.24	$836,635.56	$54,237.32	6.9%
590,000	$66,528.34	$71,036.22	$4,507.88	6.8%	$65,913.27	$70,689.81	$4,776.54	7.2%	$795,879.80	$851,049.00	$55,169.20	6.9%
600,000	$67,655.30	$72,239.34	$4,584.04	6.8%	$67,029.72	$71,886.93	$4,857.21	7.2%	$809,361.28	$865,462.44	$56,101.16	6.9%

Average Winter Usage **Average Summer Usage**

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

General Service Primary (GP) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh)	Current Winter Total Full Service Charges	Proposed Winter Total Full Service Charges	Change in Total Winter Full Service Charges	Percentage Change in Total Winter Full Service Charges	Current Summer Total Full Service Charges	Proposed Summer Total Full Service Charges	Change in Total Summer Full Service Charges	Percentage Change in Total Summer Full Service Charges	Current Annual Total Full Service Charges {1}	Proposed Annual Total Full Service Charges {1}	Change in Total Annual Full Service Charges	Percentage Change in Total Annual Full Service Charges
(a)	(b)	(c)	(d) = (c) - (b)	(e) = (d) / (b)	(f)	(g)	(h) = (g) - (f)	(i) = (h) / (f)	(j)	(k)	(l) = (k) - (j)	(m) = (l) / (j)
200,000	$18,202.91	$19,148.39	$945.48	5.2%	$17,571.20	$18,569.24	$998.04	5.7%	$215,908.08	$227,464.08	$11,556.00	5.4%
210,000	$19,110.54	$20,102.45	$991.91	5.2%	$18,447.18	$19,494.25	$1,047.07	5.7%	$226,673.04	$238,796.60	$12,123.56	5.3%
220,000	$20,018.17	$21,056.50	$1,038.33	5.2%	$19,323.15	$20,419.24	$1,096.09	5.7%	$237,437.96	$250,128.96	$12,691.00	5.3%
230,000	$20,925.80	$22,010.56	$1,084.76	5.2%	$20,199.13	$21,344.25	$1,145.12	5.7%	$248,202.92	$261,461.48	$13,258.56	5.3%
240,000	$21,832.14	$22,963.14	$1,131.00	5.2%	$21,073.77	$22,267.72	$1,193.95	5.7%	$258,952.20	$272,776.00	$13,823.80	5.3%
250,000	$22,740.56	$23,917.98	$1,177.42	5.2%	$21,950.53	$23,193.51	$1,242.98	5.7%	$269,726.60	$284,117.88	$14,391.28	5.3%
260,000	$23,648.18	$24,872.03	$1,223.85	5.2%	$22,826.50	$24,118.51	$1,292.01	5.7%	$280,491.44	$295,450.28	$14,958.84	5.3%
270,000	$24,555.82	$25,826.08	$1,270.26	5.2%	$23,702.48	$25,043.51	$1,341.03	5.7%	$291,256.48	$306,782.68	$15,526.20	5.3%
280,000	$25,462.94	$26,779.45	$1,316.51	5.2%	$24,578.45	$25,968.51	$1,390.06	5.7%	$302,017.32	$318,109.64	$16,092.32	5.3%
290,000	$26,371.35	$27,734.28	$1,362.93	5.2%	$25,455.21	$26,894.29	$1,439.08	5.7%	$312,791.64	$329,451.40	$16,659.76	5.3%
300,000	$27,278.99	$28,688.35	$1,409.36	5.2%	$26,331.19	$27,819.30	$1,488.11	5.7%	$323,556.68	$340,784.00	$17,227.32	5.3%
310,000	$28,185.33	$29,640.94	$1,455.61	5.2%	$27,205.83	$28,742.79	$1,536.96	5.6%	$334,305.96	$352,098.68	$17,792.72	5.3%
320,000	$29,092.95	$30,594.98	$1,502.03	5.2%	$28,081.80	$29,667.78	$1,585.98	5.6%	$345,070.80	$363,430.96	$18,360.16	5.3%
330,000	$30,000.59	$31,549.04	$1,548.45	5.2%	$28,957.78	$30,592.79	$1,635.01	5.6%	$355,835.84	$374,763.48	$18,927.64	5.3%
340,000	$30,908.21	$32,503.08	$1,594.87	5.2%	$29,833.75	$31,517.78	$1,684.03	5.6%	$366,600.68	$386,095.76	$19,495.08	5.3%
326,785	**$29,708.81**	**$31,242.32**	**$1,533.51**	**5.2%**	$28,676.02	$30,295.20	$1,619.18	5.6%	$352,374.56	$371,119.36	$18,744.80	5.3%
350,000	$31,816.12	$33,457.24	$1,641.12	5.2%	$30,710.51	$32,443.57	$1,733.06	5.6%	$377,371.00	$397,432.20	$20,061.20	5.3%
360,000	$32,723.76	$34,411.30	$1,687.54	5.2%	$31,586.49	$33,368.58	$1,782.09	5.6%	$388,136.04	$408,764.72	$20,628.68	5.3%
370,000	$33,631.38	$35,365.34	$1,733.96	5.2%	$32,462.46	$34,293.57	$1,831.11	5.6%	$398,900.88	$420,097.00	$21,196.12	5.3%
380,000	$34,537.72	$36,317.93	$1,780.21	5.2%	$33,337.10	$35,217.05	$1,879.95	5.6%	$409,650.16	$431,411.64	$21,761.48	5.3%
390,000	$35,445.36	$37,271.99	$1,826.63	5.2%	$34,213.08	$36,142.05	$1,928.97	5.6%	$420,415.20	$442,744.12	$22,328.92	5.3%
369,171	$33,555.06	$35,285.10	$1,730.04	5.2%	**$32,388.56**	**$34,215.45**	**$1,826.89**	**5.6%**	$397,994.72	$419,142.60	$21,147.88	5.3%
400,000	$36,353.77	$38,226.83	$1,873.06	5.2%	$35,089.84	$37,067.84	$1,978.00	5.6%	$431,189.52	$454,086.00	$22,896.48	5.3%
410,000	$37,261.40	$39,180.88	$1,919.48	5.2%	$35,965.81	$37,992.84	$2,027.03	5.6%	$441,954.44	$465,418.40	$23,463.96	5.3%
420,000	$38,168.52	$40,134.25	$1,965.73	5.2%	$36,841.79	$38,917.84	$2,076.05	5.6%	$452,715.32	$476,745.36	$24,030.04	5.3%
430,000	$39,076.15	$41,088.30	$2,012.15	5.1%	$37,717.76	$39,842.84	$2,125.08	5.6%	$463,480.24	$488,077.76	$24,597.52	5.3%
440,000	$39,983.79	$42,042.35	$2,058.56	5.1%	$38,593.74	$40,767.84	$2,174.10	5.6%	$474,245.28	$499,410.16	$25,164.88	5.3%
450,000	$40,890.63	$42,995.62	$2,104.99	5.1%	$39,468.38	$41,691.32	$2,222.94	5.6%	$484,998.56	$510,730.24	$25,731.68	5.3%
460,000	$41,798.54	$43,949.78	$2,151.24	5.1%	$40,345.14	$42,617.11	$2,271.97	5.6%	$495,768.88	$522,066.68	$26,297.80	5.3%
470,000	$42,706.17	$44,903.83	$2,197.66	5.1%	$41,221.11	$43,542.10	$2,320.99	5.6%	$506,533.80	$533,399.04	$26,865.24	5.3%
480,000	$43,613.80	$45,857.89	$2,244.09	5.1%	$42,097.09	$44,467.11	$2,370.02	5.6%	$517,298.76	$544,731.56	$27,432.80	5.3%
490,000	$44,520.92	$46,811.25	$2,290.33	5.1%	$42,973.06	$45,392.10	$2,419.04	5.6%	$528,059.60	$556,058.40	$27,998.80	5.3%
500,000	$45,429.33	$47,766.09	$2,336.76	5.1%	$43,849.82	$46,317.89	$2,468.07	5.6%	$538,833.92	$567,400.28	$28,566.36	5.3%
510,000	$46,336.97	$48,720.15	$2,383.18	5.1%	$44,725.80	$47,242.90	$2,517.10	5.6%	$549,598.96	$578,732.80	$29,133.84	5.3%
520,000	$47,243.79	$49,673.37	$2,429.58	5.1%	$45,600.42	$48,166.33	$2,565.91	5.6%	$560,352.00	$590,052.28	$29,700.28	5.3%
530,000	$48,150.90	$50,626.73	$2,475.83	5.1%	$46,476.39	$49,091.32	$2,614.93	5.6%	$571,112.76	$601,379.12	$30,266.36	5.3%
540,000	$49,058.54	$51,580.79	$2,522.25	5.1%	$47,352.37	$50,016.33	$2,663.96	5.6%	$581,877.80	$612,711.64	$30,833.84	5.3%
560,000	$50,874.07	$53,488.99	$2,614.92	5.1%	$49,105.10	$51,867.11	$2,762.01	5.6%	$603,412.96	$635,380.36	$31,967.40	5.3%
580,000	$52,688.55	$55,396.32	$2,707.77	5.1%	$50,855.72	$53,715.60	$2,859.88	5.6%	$624,931.28	$658,032.96	$33,101.68	5.3%
600,000	$54,503.30	$57,303.73	$2,800.43	5.1%	$52,607.66	$55,565.59	$2,957.93	5.6%	$646,457.04	$680,692.20	$34,235.16	5.3%
620,000	$56,319.35	$59,212.63	$2,893.28	5.1%	$54,360.40	$57,416.39	$3,055.99	5.6%	$667,996.40	$703,366.60	$35,370.20	5.3%
640,000	$58,134.10	$61,120.05	$2,985.95	5.1%	$56,112.35	$59,266.39	$3,154.04	5.6%	$689,522.20	$726,025.96	$36,503.76	5.3%
660,000	$59,948.57	$63,027.37	$3,078.80	5.1%	$57,862.96	$61,114.86	$3,251.90	5.6%	$711,040.40	$748,678.40	$37,638.00	5.3%
680,000	$61,764.12	$64,935.58	$3,171.46	5.1%	$59,615.70	$62,965.65	$3,349.95	5.6%	$732,575.76	$771,347.24	$38,771.48	5.3%
700,000	$63,579.38	$66,843.68	$3,264.30	5.1%	$61,367.65	$64,815.65	$3,448.00	5.6%	$754,105.64	$794,012.04	$39,906.40	5.3%
720,000	$65,394.13	$68,751.11	$3,356.98	5.1%	$63,119.05	$66,664.92	$3,545.87	5.6%	$775,629.24	$816,668.56	$41,039.32	5.3%
740,000	$67,208.89	$70,658.54	$3,449.65	5.1%	$64,871.00	$68,514.92	$3,643.92	5.6%	$797,155.12	$839,328.00	$42,172.88	5.3%
760,000	$69,024.15	$72,566.64	$3,542.49	5.1%	$66,622.95	$70,364.92	$3,741.97	5.6%	$818,685.00	$861,992.80	$43,307.80	5.3%
780,000	$70,839.69	$74,474.85	$3,635.16	5.1%	$68,375.69	$72,215.71	$3,840.02	5.6%	$840,220.28	$884,661.64	$44,441.36	5.3%
800,000	$72,654.16	$76,382.16	$3,728.00	5.1%	$70,126.30	$74,064.19	$3,937.89	5.6%	$861,738.48	$907,314.04	$45,575.56	5.3%

Average Winter Usage **Average Summer Usage**

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

General Service Transmission (GT) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh)	Current Winter Total Full Service Charges	Proposed Winter Total Full Service Charges	Change in Total Winter Full Service Charges	Percentage Change in Total Winter Full Service Charges	Current Summer Total Full Service Charges	Proposed Summer Total Full Service Charges	Change in Total Summer Full Service Charges	Percentage Change in Total Summer Full Service Charges	Current Annual Total Full Service Charges {1}	Proposed Annual Total Full Service Charges {1}	Change in Total Annual Full Service Charges	Percentage Change in Total Annual Full Service Charges
(a)	(b)	(c)	(d) = (c) - (b)	(e) = (d) / (b)	(f)	(g)	(h) = (g) - (f)	(i) = (h) / (f)	(j)	(k)	(l) = (k) - (j)	(m) = (l) / (j)
200,000	$16,723.22	$17,485.68	$762.46	4.6%	$14,791.25	$15,563.31	$772.06	5.2%	$192,950.76	$202,138.68	$9,187.92	4.8%
250,000	$20,847.75	$21,781.28	$933.53	4.5%	$18,433.04	$19,378.66	$945.62	5.1%	$240,514.16	$251,764.88	$11,250.72	4.7%
300,000	$24,971.82	$26,076.56	$1,104.74	4.4%	$22,074.04	$23,193.23	$1,119.19	5.1%	$288,070.72	$301,385.40	$13,314.68	4.6%
350,000	$29,095.90	$30,371.84	$1,275.94	4.4%	$25,714.68	$27,007.34	$1,292.66	5.0%	$335,625.92	$351,004.08	$15,378.16	4.6%
400,000	$33,220.00	$34,667.18	$1,447.18	4.4%	$29,355.71	$30,821.95	$1,466.24	5.0%	$383,182.84	$400,625.24	$17,442.40	4.6%
450,000	$37,344.52	$38,962.78	$1,618.26	4.3%	$32,997.48	$34,637.31	$1,639.83	5.0%	$430,746.08	$450,251.48	$19,505.40	4.5%
500,000	$41,468.58	$43,258.07	$1,789.49	4.3%	$36,638.47	$38,451.90	$1,813.43	4.9%	$478,302.52	$499,872.16	$21,569.64	4.5%
550,000	$45,593.45	$47,554.15	$1,960.70	4.3%	$40,280.25	$42,267.25	$1,987.00	4.9%	$525,868.60	$549,502.20	$23,633.60	4.5%
600,000	$49,717.17	$51,848.96	$2,131.79	4.3%	$43,921.25	$46,081.83	$2,160.58	4.9%	$573,422.36	$599,119.00	$25,696.64	4.5%
650,000	$53,842.04	$56,145.03	$2,302.99	4.3%	$47,563.04	$49,897.18	$2,334.14	4.9%	$620,988.48	$648,748.96	$27,760.48	4.5%
700,000	$57,966.12	$60,440.31	$2,474.19	4.3%	$51,204.03	$53,711.75	$2,507.72	4.9%	$668,545.08	$698,369.48	$29,824.40	4.5%
750,000	$62,090.63	$64,735.93	$2,645.30	4.3%	$54,845.81	$57,527.13	$2,681.32	4.9%	$716,108.28	$747,995.96	$31,887.68	4.5%
800,000	$66,214.71	$69,031.21	$2,816.50	4.3%	$58,486.80	$61,341.69	$2,854.89	4.9%	$763,664.88	$797,616.44	$33,951.56	4.4%
850,000	$70,339.57	$73,327.28	$2,987.71	4.2%	$62,128.59	$65,157.06	$3,028.47	4.9%	$811,230.92	$847,246.48	$36,015.56	4.4%
900,000	$74,463.30	$77,622.08	$3,158.78	4.2%	$65,769.59	$68,971.63	$3,202.04	4.9%	$858,784.76	$896,863.16	$38,078.40	4.4%
950,000	$78,588.16	$81,918.16	$3,330.00	4.2%	$69,411.37	$72,786.98	$3,375.61	4.9%	$906,350.76	$946,493.20	$40,142.44	4.4%
1,000,000	$82,712.23	$86,213.45	$3,501.22	4.2%	$73,052.36	$76,601.57	$3,549.21	4.9%	$953,907.28	$996,113.88	$42,206.60	4.4%
1,047,467	$86,627.08	$90,290.72	**$3,663.64**	**4.2%**	$76,508.60	$80,222.48	$3,713.88	4.9%	$999,051.04	$1,043,215.68	$44,164.64	4.4%
1,050,000	$86,836.30	$90,508.74	$3,672.44	4.2%	$76,693.00	$80,415.67	$3,722.67	4.9%	$1,001,462.40	$1,045,732.60	$44,270.20	4.4%
1,100,000	$90,960.82	$94,804.34	$3,843.52	4.2%	$80,334.79	$84,231.02	$3,896.23	4.8%	$1,049,025.72	$1,095,358.80	$46,333.08	4.4%
1,066,889	$88,229.79	$91,960.05	$3,730.26	4.2%	**$77,923.39**	**$81,704.72**	**$3,781.33**	**4.9%**	$1,017,531.88	$1,062,499.28	$44,967.40	4.4%
1,150,000	$95,084.89	$99,099.62	$4,014.73	4.2%	$83,975.78	$88,045.60	$4,069.82	4.8%	$1,096,582.24	$1,144,979.36	$48,397.12	4.4%
1,200,000	$99,209.80	$103,395.75	$4,185.95	4.2%	$87,617.60	$91,861.01	$4,243.41	4.8%	$1,144,148.80	$1,194,610.04	$50,461.24	4.4%
1,250,000	$103,333.52	$107,690.56	$4,357.04	4.2%	$91,258.59	$95,675.57	$4,416.98	4.8%	$1,191,702.52	$1,244,226.76	$52,524.24	4.4%
1,300,000	$107,458.39	$111,986.63	$4,528.24	4.2%	$94,900.37	$99,490.94	$4,590.57	4.8%	$1,239,268.60	$1,293,856.80	$54,588.20	4.4%
1,350,000	$111,582.46	$116,281.92	$4,699.46	4.2%	$98,541.36	$103,305.52	$4,764.16	4.8%	$1,286,825.12	$1,343,477.44	$56,652.32	4.4%
1,400,000	$115,706.97	$120,577.53	$4,870.56	4.2%	$102,183.14	$107,120.88	$4,937.74	4.8%	$1,334,388.32	$1,393,103.76	$58,715.44	4.4%
1,450,000	$119,831.06	$124,872.81	$5,041.75	4.2%	$105,824.15	$110,935.46	$5,111.31	4.8%	$1,381,945.08	$1,442,724.32	$60,779.24	4.4%
1,500,000	$123,955.91	$129,168.87	$5,212.96	4.2%	$109,465.93	$114,750.81	$5,284.88	4.8%	$1,429,511.00	$1,492,354.20	$62,843.20	4.4%
1,550,000	$128,080.00	$133,464.17	$5,384.17	4.2%	$113,106.93	$118,565.39	$5,458.46	4.8%	$1,477,067.72	$1,541,974.92	$64,907.20	4.4%
1,600,000	$132,204.49	$137,759.77	$5,555.28	4.2%	$116,748.70	$122,380.75	$5,632.05	4.8%	$1,524,630.72	$1,591,601.16	$66,970.44	4.4%
1,650,000	$136,328.59	$142,055.06	$5,726.47	4.2%	$120,389.70	$126,195.33	$5,805.63	4.8%	$1,572,187.52	$1,641,221.80	$69,034.28	4.4%
1,700,000	$140,452.66	$146,350.35	$5,897.69	4.2%	$124,030.35	$130,009.43	$5,979.08	4.8%	$1,619,742.68	$1,690,840.52	$71,097.84	4.4%
1,750,000	$144,577.18	$150,645.95	$6,068.77	4.2%	$127,672.13	$133,824.79	$6,152.66	4.8%	$1,667,305.96	$1,740,466.76	$73,160.80	4.4%
1,800,000	$148,701.25	$154,941.23	$6,239.98	4.2%	$131,313.13	$137,639.36	$6,326.23	4.8%	$1,714,862.52	$1,790,087.28	$75,224.76	4.4%
1,850,000	$152,826.11	$159,237.32	$6,411.21	4.2%	$134,954.91	$141,454.73	$6,499.82	4.8%	$1,762,428.52	$1,839,717.48	$77,288.96	4.4%
1,900,000	$156,949.83	$163,532.13	$6,582.30	4.2%	$138,595.90	$145,269.30	$6,673.40	4.8%	$1,809,982.24	$1,889,334.24	$79,352.00	4.4%
1,950,000	$161,074.73	$167,828.25	$6,753.52	4.2%	$142,237.72	$149,084.71	$6,846.99	4.8%	$1,857,548.72	$1,938,964.84	$81,416.12	4.4%
2,000,000	$165,198.81	$172,123.53	$6,924.72	4.2%	$145,878.71	$152,899.28	$7,020.57	4.8%	$1,905,105.32	$1,988,585.36	$83,480.04	4.4%
2,050,000	$169,323.32	$176,419.13	$7,095.81	4.2%	$149,520.49	$156,714.65	$7,194.16	4.8%	$1,952,668.52	$2,038,211.64	$85,543.12	4.4%
2,100,000	$173,447.40	$180,714.41	$7,267.01	4.2%	$153,161.49	$160,529.21	$7,367.72	4.8%	$2,000,225.16	$2,087,832.12	$87,606.96	4.4%
2,150,000	$177,572.27	$185,010.48	$7,438.21	4.2%	$156,803.27	$164,344.57	$7,541.30	4.8%	$2,047,791.24	$2,137,462.12	$89,670.88	4.4%
2,200,000	$181,696.34	$189,305.78	$7,609.44	4.2%	$160,444.26	$168,159.16	$7,714.90	4.8%	$2,095,347.76	$2,187,082.88	$91,735.12	4.4%
2,250,000	$185,820.85	$193,601.38	$7,780.53	4.2%	$164,086.04	$171,974.51	$7,888.47	4.8%	$2,142,910.96	$2,236,709.08	$93,798.12	4.4%
2,300,000	$189,944.93	$197,896.66	$7,951.73	4.2%	$167,727.04	$175,789.09	$8,062.05	4.8%	$2,190,467.60	$2,286,329.64	$95,862.04	4.4%
2,350,000	$194,069.79	$202,192.74	$8,122.95	4.2%	$171,368.83	$179,604.45	$8,235.62	4.8%	$2,238,033.64	$2,335,959.72	$97,926.08	4.4%
2,400,000	$198,193.52	$206,487.55	$8,294.03	4.2%	$175,009.47	$183,418.54	$8,409.07	4.8%	$2,285,586.04	$2,385,574.56	$99,988.52	4.4%
2,450,000	$202,317.58	$210,782.84	$8,465.26	4.2%	$178,650.46	$187,233.12	$8,582.66	4.8%	$2,333,142.48	$2,435,195.20	$102,052.72	4.4%

Average Winter Usage **Average Summer Usage**

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Exhibit JC - 12
Schedule YP - 5

Current Tariff

Parts I, II and III

TARIFF for SERVICE

Part I

General Information

Part II

Standard Terms and Conditions

Issued: December 12, 2016 **Effective: January 1, 2017**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER16040383 and ET14101270 dated December 12, 2016

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

PART I
GENERAL INFORMATION
TABLE OF CONTENTS

General Information

A - Service Tariff: This tariff for Service ("Tariff") of Jersey Central Power & Light Company, ("Company"), is filed with the Board of Public Utilities of New Jersey ("BPU") pursuant to NJAC 14:3-1.3. The Standard Terms and Conditions set forth in Part II of this Tariff state the conditions under which Service is rendered, and govern the Company's provision of Full Service, Delivery Service and/or other Services to the extent applicable. The Service Classifications and Riders contained in Part III of this Tariff state the basis for computing the charges to Customers for Service. Except where specifically modified by written contract, all applicable provisions of this Tariff constitute, or are a part of, each service contract, express or implied, and both the Customer and the Company shall be bound thereby.

B - Revision of Tariff: The Company may at any time, and in any manner permitted by law and the applicable rules and regulations of the BPU, supplement, terminate, change, or modify this Tariff or any part thereof.

C - Exchange of Information: The Company will, at the Customer's request, explain the provisions of its Tariff and inform the Customer as to the conditions under which Service can be obtained from the Company's system. It is the responsibility of the Customer or his agent, before making his initial electrical installation or planning material changes in an existing installation, to obtain from the Company information regarding the characteristics of available Service, its designation of the point of attachment of the service connection and meter location, and such other information as may be necessary to assure that the Customer's installation will be compatible with the facilities and Service the Company will supply.

D - Statements by Agents: No representative of the Company has authority to modify any provision contained in this Tariff or bind the Company by any promise or representation contrary thereto.

E - Agreements and Contracts: Standard agreements to provide Service shall be in accordance with Parts II and III of this Tariff. As a condition for establishing, continuing, or resuming the provision of Service in a situation where the Company incurs or will incur greater than normal investment cost or operating expense in order to meet the Customer's special or unusual Service requirements, or to protect the Company's system from undue disturbance of voltage regulation or other adverse effects, and in order to avoid undue discrimination, the Company may require an agreement for a longer term than specified in the applicable Service Classification, may require a contribution in aid of construction and may establish such minimum charges and facilities charges as may be equitable under the circumstances.

General Information

F – Definitions: The following terms are herein defined for general reference to assist in their application in Parts II and III of this Tariff.

(1) Alternative Electric Supplier: Any person, corporation or other entity, other than the Company, that has applied for and received an electric power supplier license from the BPU.

(2) Applicant: Any person, corporation or other entity that (a) desires to receive from the Company electric generation or any other Service provided for in this Tariff, (b) complies completely with all Company requirements for obtaining electric generation or any other Service provided for in this Tariff, (c) has filed and is awaiting Company approval of its application for Service, and (d) is not yet actually receiving from the Company any Service provided for in this Tariff. An Applicant shall become a Customer for purposes of this Tariff only after it actually starts receiving the applicable Service from the Company under this Tariff.

(3) Beneficiary: The person, corporation or the entity financially benefiting from the service.

(4) Billing Month: Generally, that calendar month in which the majority of the Company's meters are read for the purpose of establishing the electric service usage of Customers for their prior 26 to 35 day period.

(5) Connected Load: The sum of the input ratings of all electric-using devices located on the Customer's premises and which are or can be, by the insertion of a fuse, closing of a switch, or any similar method, connected simultaneously to the Company's Service. Although the manufacturer's nameplate rating may be used to determine the input rating of any particular device, the Company may instead determine the input rating of any device by test.

(6) Contract Capacity: That electrical capacity which the Customer specifies is needed to supply the Customer's requirements for Service and which the Company agrees to furnish through either Full Service or Delivery Service.

(7) Contract Location: Each metering point shall be considered a contract location and shall be metered and billed under a separate service contract. In cases where unmetered service is provided, the Point of Delivery shall be considered a contract location.

(8) Customer: Any person, partnership, association, corporation, or agency of municipal, county, state, or federal government receiving any Service rendered by the Company under this Tariff at a Contract Location. The term "Customer" shall also include Applicant when, in the Company's opinion, the specific provision of this Tariff was intended to be so inclusive. Any customer receiving Delivery Service shall simultaneously be a customer of an Alternative Electric Supplier.

(9) Delivery Service: The provision of electric distribution and other services by the Company to Customers under this Tariff who purchase their electric generation service from Alternative Electric Suppliers.

General Information

(10) End User: A person who receives, uses or consumes service. An end user may or may not be a customer as defined herein.

(11) Full Service: The provision of electric distribution and other services by the Company to Customers under this Tariff who purchase their electric generation service from the Company.

(12) Line Extension: This term applies to those overhead or underground facilities for the distribution or transmission of electrical energy to serve new Customers or the enlarged load of existing Customers which are constructed by the Company as a specific project (a) on a public highway and/or (b) on a right-of-way over private or public land to serve one or more Customers. Such an extension may be an addition to and/or upgrade of existing facilities or a new installation of facilities. A line extension originates at the pole or point at which it is connected to the existing facilities or where such upgraded facilities are required and it extends to and includes (a) the most remote pole or point from which a "Service Drop" or "Underground Service Connection" is installed, or (b) to the point at which a "Service Lateral" originates.

(13) Point of Delivery: The point at which the Customer receives Service and from which point inward, with respect to the premises served, the Customer assumes responsibility and liability for the presence or use of electricity in the Customer's installation.

(14) Residence: A structure or portion of a structure intended for use as sleeping quarters by a person or persons, and containing cooking and sanitary facilities.

Auxiliary Residential Purposes: Electric loads used on the premises in conjunction with the operation, use, and maintenance of an individual Residence. Such loads may include yard lighting, swimming pool pumps and heaters, saunas, driveway heaters, household workshops, yard maintenance equipment, and garages or outbuildings when used in conjunction with the operation, use, or maintenance of the Residence.

Multiple Residential Structure: A structure containing more than one Residence and having no direct access between them except from the outside or a common hall.

Group Residential Structure: A structure containing a Residence and five or more sleeping quarters intended for rental purposes, and not qualifying as a Multiple Residential Structure.

Individual Residential Structure: A structure containing a Residence and not qualifying as a Multiple Residential Structure or a Group Residential Structure.

Incidental Non-Residential Purposes: Non-Residential loads totaling 10 kW or less and which are less than 30% of the Residential and/or Auxiliary Residential connected load it is metered with.

Non-Residential Purposes: Electric loads which do not qualify under "residential purposes" or "auxiliary residential purposes." Such loads shall include but are not limited to, ceramic kilns, electric welders, greenhouses, and loads used for farming, business, professional, avocation, or animal housing purposes.

General Information

(15) Service: The term "Service" (generally upper case), as used in this Tariff, references any electricity, or access to electricity, that is provided by the Company pursuant to this Tariff, or anything related to the provision of electricity, or access to electricity, provided or rendered by the Company pursuant to this Tariff. Note that the word "service" (generally lower case) is also used from time to time in this Tariff to reference services rendered by entities other than the Company (such as Alternative Electric Suppliers). The distinction between the Company's Services and other entities' services is apparent from the context, and the use of upper and lower case is intended to aid the reader in taking note of the distinction.

(16) Service Connection: The conductors and equipment for delivering Service from the Company's supply system to the service entrance on the customer's premises. If overhead, such Service Connection, also known as a "Service Drop," terminates at a fixture or fixtures installed on the Customer's building or structure at a location designated by the Company which will provide the required clearance of the Service Drop conductors with respect to intervening objects or surfaces. An underground Service Connection is the equivalent of the overhead Service Connection and terminates either at the Customer's over-current protective device on the inside of the first foundation wall adjacent to the street on which the Company's mains are situated or at the meter base installed as part of the “Service Entrance”. If the Company's primary or transmission delivery system is directly connected to the Customer's facilities, such as through transformation or circuit breaking facilities which constitute the service connection, the Point of Delivery shall be the point of connection between the Customer's facilities and the Company's facilities, which is usually identified in a written contract that provides for such direct connection. In other instances, the Point of Delivery is as specified in the definition of "Service Entrance."

(17) Service Drop: A Company-owned overhead Service Connection.

(18) Service Entrance or Entrance Facilities: In general, the conductors or accessory equipment by which electricity is carried from the Service Connection to the supply side of the devices protecting the Customer's circuits. If the Service Entrance is owned by the Customer, it is referred to as "Customer's Entrance Facilities" and the Point of Delivery is the junction of the Service Connection conductors with the Service Entrance. If the Service Entrance is owned by the Company, it is referred to as "Company's Service Entrance" and the Point of Delivery is at the supply side of the devices protecting the Customer's circuits. The metering devices are not included as part of the Service Entrance**.**

(19) Service Lateral: The electrical facilities constituting a branch from the Company's system, installed on private property to serve a single Customer. A Service Lateral may be either overhead or underground. If overhead, the Service Lateral originates at the pole or point at which connection is made to the existing system or line extension and extends to the pole or other aerial support where the Service Drop originates. When a secondary underground Service Lateral is owned, installed, and maintained by the Customer, it shall consist of the specified conduit and cable between its connection with the Company's system and the premises where the Service is to be used. A non-secondary overhead or underground Service Lateral may provide a circuit connection to Company-owned or Customer-owned transformers set in a vault or on a pad on the Customer's premises.

General Information

(20) Standby Service: Service that the Customer may receive or may request that the Company furnish in the event of a breakdown, shutdown, failure, or other impairment of a generator on the Customer's premises, from which the Customer normally receives all or a portion of his energy requirements.

(21) Summary Billing: A Service whereby the Company will add together the charges for multiple Full Service accounts maintained by one Customer and provide the Customer with a single bill.

(22) Tampering: Tampering shall mean connecting or causing to be connected by wire or any other device with the wires, cables or conductors of the Company, or connecting, disconnecting or shunting the meters, cables, conductors or other equipment of the Company, without the Company’s permission. (See Part II, Sections 5.03, 6.04, 6.05, 6.06, 6.07, 6.08 and 7.03) (See N.J.S.A. 2C:20-8)

General Information

G - Municipalities Served: The following list designates those municipalities in which the Company serves the public through its distribution facilities.

BURLINGTON COUNTY
Chesterfield Twp.
New Hanover Twp.
North Hanover Twp.
Pemberton Boro
Pemberton Twp.
Southhampton Twp.
Springfield Twp.
Woodland Twp.
Wrightstown Boro

ESSEX COUNTY
Livingston Twp.
Maplewood Twp.
Millburn Twp.

HUNTERDON COUNTY
Alexandria Twp.
Bethlehem Twp.
Bloomsbury Boro
Califon Boro
Clinton, Town of
Clinton Twp.
Delaware Twp.
East Amwell Twp.
Flemington Boro
Franklin Twp.
Frenchtown Boro
Glen Gardner Boro
Hampton Boro
High Bridge Boro
Holland Twp.
Kingwood Twp.
Lambertville, City of
Lebanon Boro
Lebanon Twp.
Milford Boro
Raritan Twp.
Readington Twp.
Stockton Boro
Tewksbury Twp.
Union Twp.
West Amwell Twp.

MERCER COUNTY
East Windsor Twp.
Hightstown Boro
Hopewell Twp.
Washington Twp.
West Windsor Twp.

MIDDLESEX COUNTY
Cranbury Twp.
East Brunswick Twp.
Helmetta Boro
Jamesburg Boro
Monroe Twp.
Old Bridge Twp.
Sayreville Boro
South Amboy, City of
South Brunswick Twp.
Spotswood Boro

MONMOUTH COUNTY
Aberdeen Twp.
Allenhurst Boro
Asbury Park, City of
Atlantic Highlands Boro
Avon-by-the Sea Boro
Belmar Boro
Bradley Beach Boro
Brielle Boro
Colts Neck Twp.
Deal Boro
Eatontown Boro
Englishtown Boro
Fair Haven Boro
Farmingdale Boro
Freehold Boro
Freehold Twp.
Hazlet Twp.
Highlands Boro
Holmdel Twp.
Howell Twp.
Interlaken Boro
Keansburg Boro
Keyport Boro

MONMOUTH COUNTY (Continued)
Little Silver Boro
Loch Arbour, Village of
Long Branch, City of
Manalapan Twp.
Manasquan Boro
Marlboro Twp.
Matawan Boro
Middletown Twp.
Millstone Twp.
Monmouth Beach Boro
Neptune City Boro
Neptune Twp.
Oceanport Boro
Ocean Twp.
Red Bank Boro
Roosevelt Boro
Rumson Boro
Sea Bright Boro
Sea Girt Boro
Shrewsbury Boro
Shrewsbury Twp.
South Belmar Boro
Spring Lake Boro
Spring Lake Heights Boro
Tinton Falls Boro
Union Beach Boro
Upper Freehold Twp.
Wall Twp.
West Long Branch Boro

MORRIS COUNTY
Boonton, Town of
Boonton Twp.
Butler Boro
Chatham Boro
Chatham Twp.
Chester Boro
Chester Twp.
Denville Twp.
Dover, Town of
East Hanover Twp.

General Information

MORRIS COUNTY (Continued)
Florham Park Boro
Hanover Twp.
Harding Twp.
Jefferson Twp.
Kinnelon Boro
Lincoln Park Boro
Long Hill Twp.
Madison Boro
Mendham Boro
Mendham Twp.
Mine Hill Twp.
Montville Twp.
Morris Twp.
Morristown, Town of
Morris Plans Boro
Mountain Lakes Boro
Mt. Arlington Boro
Mt. Olive Twp.
Netcong Boro
Parsippany-Troy Hills Twp.
Pequannock Twp.
Randolph Twp.
Riverdale Boro
Rockaway Boro
Rockaway Twp
Roxbury Twp.
Victory Gardens Boro
Washington Twp.
Wharton Boro

OCEAN COUNTY
Barnegat Twp.
Bay Head Boro
Beachwood Boro
Berkeley Twp.
Brick Twp.
Dover Twp.
Island Heights Boro
Jackson Twp.
Lacey Twp.
Lakehurst Boro
Lakewood Twp.
Lavallette Boro
Manchester Twp.

OCEAN COUNTY (Continued)
Mantoloking Boro
Ocean Twp.
Ocean Gate Boro
Pine Beach Boro
Plumsted Twp.
Point Pleasant Boro
Point Pleasant Beach Boro
Seaside Heights Boro
Seaside Park Boro
South Toms River

PASSAIC COUNTY
Bloomingdale Boro
Pompton Lakes Boro
Ringwood Boro
Wanaque Boro
Wayne Twp.
West Milford Twp.

SOMERSET COUNTY
Bedminster Twp.
Bernards Twp.
Bernardsville Boro
Branchburg Twp.
Bridgewater Twp.
Far Hills Boro
Green Brook Twp.
Hillsborough Twp.
Peapack-Gladstone Boro
Warren Twp.
Watchung Boro

SUSSEX COUNTY
Andover Boro
Andover Twp.
Branchville Boro
Byram Twp.
Frankford Twp.
Franklin Boro
Fredon Twp.
Green Twp.
Hamburg Boro
Hampton Twp.
Hardyston Twp.

SUSSEX COUNTY (Continued)
Hopatcong Boro
Lafayette Twp.
Montague Twp.
Newton, Town of
Ogdensburg Boro
Sandyston Twp.
Sparta Twp.
Stanhope Boro
Stillwater Twp.
Sussex Boro
Vernon Twp.
Wallpack Twp.
Wantage Twp.

UNION COUNTY
Berkeley Heights Twp.
Mountainside Boro
New Providence Boro
Springfield Twp.
Summit, City of

WARREN COUNTY
Allamuchy Twp.
Alpha Boro
Belvidere, Town of
Blairstown Twp.
Franklin Twp.
Frelinghuysen Twp.
Greenwich Twp.
Hackettstown, Town of
Hardwick Twp.
Harmony Twp.
Hope Twp.
Independence Twp.
Knowlton Twp.
Liberty Twp.
Lopatcong Twp.
Mansfield Twp.
Oxford Twp.
Phillipsburg, Town of
Pohatcong Twp.
Washington Boro
Washington Twp.
White Twp

General Information

H – Customer Contact Information:

Emergency / Power Outage Reporting	1-888-544-4877
General Customer Service	1-800-662-3115
Payment Options	1-800-962-0383
Telecommunications Relay Service (TRS) for the Hearing Impaired	711
Morristown General Office 300 Madison Avenue, Morristown, NJ 07962-1911	1-973-401-8200

Customer Billing Questions or Complaints
JCP&L 76 S. Main Street, A-RPC, Akron, OH 44308-1890

Website:
http://www.firstenergycorp.com

Northern Region Business Offices:

Morristown	300 Madison Avenue, Morristown, NJ 07962	**ALL**
Hopatcong	175 Center Street, Landing, NJ 07850	**TELEPHONE**
Phillipsburg	400 Lincoln Street, Phillipsburg, NJ 08865	**INQUIRIES**
		PLEASE USE
Central Region Business Offices:		**CUSTOMER**
Allenhurst	300 Main Street, Allenhurst, NJ 07711	**CONTACT**
Toms River	25 Adafre Avenue, Toms River, NJ 08753	**INFORMATION**
Old Bridge	999 Englishtown Road, Old Bridge, NJ 08857	**ABOVE**

PART II
STANDARD TERMS AND CONDITIONS
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Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER16040383 and ET14101270 dated December 12, 2016

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

PART II
STANDARD TERMS AND CONDITIONS
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STANDARD TERMS AND CONDITIONS
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PART II
STANDARD TERMS AND CONDITIONS – TABLE OF CONTENTS

Section 1 - Service Availability

NOTE: Unless specifically stated otherwise, Part II of the Company's Tariff (Standard Terms and Conditions) generally describes the responsibilities of and obligations between Customers and the Company. Specific standards governing the relationship between Customers and the Alternative Electric Supplier and between the Alternative Electric Supplier and the Company have been set forth by the BPU and are noted with references to such BPU Order(s) where applicable to the Company's Tariff.

1.01 Characteristics of Service: The standard electrical supply service provided by the Company is alternating current with a nominal frequency of 60 hertz. Not all types of service listed below are available at all locations, and service voltages other than secondary may be specified by the Company under special conditions such as may relate to the location, size, or type of load. The Company may specify the voltage, phase, and minimum and maximum load that it will supply at any particular voltage. The Company will furnish transformation facilities for secondary service up to a maximum of 300 KVA pole-mounted or 2500 KVA pad-mounted per contract location. Contract locations requiring in excess of these limits may, at the Company's discretion, be provided untransformed service, in which case the customer shall install, own, operate, and maintain the necessary transformation and associated facilities, except metering, in accordance with Company service requirements. Subject to the foregoing limitations, the types of service available with their nominal voltages are:

Secondary Service:

Single-phase	2 wire	120 volts
Single-phase	3 wire	120/240 volts
Single-phase	3 wire	120/208Y volts
Three-phase	4 wire	120/240 volts
Three-phase	4 wire	120/208Y volts
Three-phase	4 wire	277/480Y volts

Primary Service:

Single-phase	2 wire	2400 volts
Single-phase	2 wire	4800 volts
Three-phase	3 wire	2400 volts
Three-phase	4 wire	2400/4160Y volts
Three-phase	3 wire	4800 volts
Single-phase	2 wire	7200 volts
Three-phase	4 wire	7200/12470Y volts
Three-phase	4 wire	7620/13200Y volts
Three-phase	3 wire	13200 volts
Three-phase	4 wire	19900/34500Y volts

Transmission Service:

Three-phase	3 wire	34500 volts
Three-phase	3 wire	115000 volts
Three-phase	3 wire	230000 volts

The Company must always be consulted regarding the type of Service to be supplied.

Section 1 - Service Availability

1.02 Single Point of Delivery: The Company will designate the Point of Delivery and meter location. Service under a particular Service Classification will be supplied to each building or contract location through only one set of Service Connection conductors and metering equipment, except where the Service Classification may require otherwise or where, for economy, engineering, or operating considerations or by reason of applicable codes or governmental regulations, the installation of more than one Service Connection is necessary. Such duplicate or auxiliary delivery sources shall be furnished by separate contract under the applicable Service Classification and special provision. Service so delivered shall be used only at the premises where the Service is connected.

1.03 Compliance with Service Classification: Service provided by the Company shall not be used for purposes other than those recognized within the applicable Service Classification or pursuant to any special provisions under which the Customer is being served. When the use of Service is not in compliance with the terms of any such special provisions or Service Classification, the Customer shall be transferred to and billed under the applicable schedule of charges or disconnected from Service as provided for in this Tariff. (Also see 4.07 and 7.03)

1.04 Residential Purposes: Electric loads required for the operation and use of an individual residence. Such loads may include that for lighting, cooking, appliance operation and water pumping as well as space and water heating. Also see Part I, Section F, Definition (14) for definitions of residence and residential structures.

1.05 Resale of Service: Customers shall not resell Service for profit. Customers who distribute electric energy from their Point of Delivery to other occupants of the premises may install metering at their own expense to determine the energy usage and amount owed to the Customer for energy usage at those sub-locations. Where the use of the premises is basically residential, such meters of sub-locations will be permitted only for those buildings constructed prior to January 1, 1978, which are co-operative or condominium residential apartment buildings, or are publicly financed or government-owned. A reasonable administrative charge may be made by the customer to the other occupants for determining and billing them for their energy usage.

For multiple occupancy residential buildings constructed after January 1, 1978, separate metering owned and installed by the Company is required for each dwelling unit as provided in the New Jersey Uniform Construction Code.

1.06 Unusual Conditions: The Company, at its sole discretion, may discontinue or refuse to provide Service to loads which might adversely affect the normal operation of facilities of the Company or its customers. Service to such loads may be provided where the customer, at its own expense, has installed corrective equipment in accordance with general or individual non-discriminatory requirements and specifications of the Company. The Company may also discontinue or refuse to supply service to loads so installed or connected that an unbalance greater than 10% exists between the phases of the customer's service. Customers should contact the Company prior to purchasing or connecting motors or other equipment to determine the maximum allowable inrush current and/or to determine the suitability of the equipment to the Company's system. (Also see Section 4.05)

Issued: December 12, 2016 **Effective: January 1, 2017**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER16040383 and ET14101270 dated December 12, 2016

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Section 1 - Service Availability

1.07 Curtailable Load Limitation: The curtailable load of all customers provided for under this Tariff shall not exceed 2.5% of the Company's annual peak load in the preceding calendar year.

1.08 Multiple Services for Transmission Customers: Service will be supplied to several delivery points at the same or different voltages as mutually agreed, providing that such delivery points are connected together by interconnecting lines and transformation facilities which are either owned, operated, and maintained by the Customer, or owned, operated, and maintained wholly or in part by the Company, upon payment to the Company of a monthly charge of 1.5% of the original cost of such facilities as are provided by the Company. Such interconnection by mutual agreement may be operated either normally closed or open, and in either case shall be changed only by or at the direction of the Company for emergency and maintenance purposes. Where such interconnection is available, each separate delivery point will be individually metered, and billing shall be based on the sum of the highest coincident demands and the sum of the kilowatt-hours registered at the individual metering points after correcting for transformation losses. Such meter registrations are not measured at transmission voltage.

Section 2 - Service Applications, Agreements & Contracts

2.01 Application and Connection: All Applicants seeking to receive any type of Service from the Company under this Tariff shall contact the Company and specifically request the type and nature of Service. An Applicant for any Service under this Tariff may be required to sign an application or contract for Service. However, the Company may, in its sole discretion, accept an oral application from an Applicant. Applicants for Service shall supply to the Company all information deemed necessary by the Company from time to time to provide such Service including, but not limited to, connected electrical load, types of electrical equipment, and the mode of operation of the electrical equipment.

Upon the receipt of Service, the Applicant shall become a Customer of the Company. At any time, the Customer shall inform the Company in advance of any proposed additions to (or decreases in) the Customer's Connected Load.

Whenever Service is initiated to any Customer in any particular location or resumed after discontinuance at the request of the Customer, a Service Charge shall be made as specified in Part III of the Tariff.

If a Delivery Service Customer, for whatever reason, receives electric supply from the Company, that Customer will be considered a Full Service Customer beginning with the date on which such electric supply is furnished to the Customer by the Company.

2.02 Forms and Information: The Company will, upon request, explain the provisions of its Tariff and the conditions under which Service can be obtained. It is the responsibility of any Applicant for new or modified Service to obtain from the Company information regarding the characteristics of available Service, the Point of Delivery of Service, its designation of the point of Service Connection and meter location, and such other information as may be necessary to assure that the Customer's installation will be compatible with the facilities and Service the Company will provide before making the initial electrical installation or planning material changes in an existing installation. The Company will furnish such application and contract forms as may be appropriate. The Applicant shall supply all of the information called for by such forms.

2.03 Selection of Service Classification: The Company will assist in the selection of the Customer’s applicable Service Classification. In furnishing such assistance, the Company assumes no responsibility whatsoever. If for any reason the Customer fails to make a selection, the Company will assign a Service Classification based upon facts at hand at the time Service is furnished. A Customer may, upon written notice to the Company, elect to change and to receive Service under any other applicable Service Classification or special provision. The Company will bill the Customer under the Service Classification so selected for Service delivered from the date of the next scheduled meter reading, but the Company may refuse to permit any further change in selection of Service Classification or special provision during the next twelve months, except as may be permissible under Section 1.03.

Section 2 - Service Applications, Agreements & Contracts

2.04 Modification or Rejection of Application: The Company may place limitations on the amount and character of Service it will provide, or may refuse to provide Service to new Customers or to any additional load of existing Customers, if it is not able to obtain, install, operate, or maintain the necessary equipment and facilities to provide such Service. The Company, after proper notice, may refuse to initiate Service or may discontinue Service to an Applicant, or to a Customer who is a member of the household or is a business associate, or landlord, of a former Customer then indebted to the Company for Services provided by the Company at any location, if the Company has reason to believe that substantially the same household or business will or does occupy the premises to be or being served and that the purpose of the present or earlier application is or was to circumvent payment of such indebtedness. However, if the household or business is not the same, the Company can only transfer the outstanding balance of amounts owed to the Company for Services provided by the Company to the former Customer of record for Service rendered at the prior location.

2.05 Contract by Use of Service: Receipt and use of Service provided by the Company shall render the recipient a Customer of the Company. If such Service is provided and accepted, or used in the absence of a written agreement for Service approved by the Company, such recipient shall be deemed to have entered into an agreement with the Company, the furnishing, receipt, and use of such Service shall be subject to the provisions of this Tariff and such Customer shall be charged for such Service in accordance with the applicable Service Classification.

2.06 Term of Contract: The term of contract is stated in the applicable Service Classification or in a written agreement. Customers shall give notice of intention to terminate Service to a responsible agent of the Company in accordance with the requirements of any applicable Service Classification or written agreement and, in any event, reasonably in advance of intended Service termination or change in Customer identity. Termination of Service on notice from the Customer, or for any other reason permitted by this Tariff prior to the completion of a contract for Service, shall not relieve the Customer from payment of the charges for the unexpired portion of the term and the same shall be due and payable immediately.

2.07 Unauthorized Use: Unauthorized connection to the Company's facilities, or the use of Service (either metered or unmetered) without Company authorization may be terminated by the Company without notice. The use of Service without notice to the Company shall render the End User or Beneficiary liable for any amount due for Service provided to the premises since the last reading of the meter as shown by the Company's records or for unmetered Service used since the last billing.

2.08 Statements by Agents: No representative of the Company has authority to modify any provision contained in this Tariff or bind the Company by any promise or representation contrary thereto, and the Company shall not be bound thereby.

2.09 Special Agreements: As a condition for establishing, continuing, or resuming the provision of Service in a situation where the Company incurs or will incur greater than normal investment cost or operating expense in order to meet the Customer's special or unusual Service requirements or to protect the Company's system from undue disturbance of voltage regulation or other adverse effects and in order to avoid undue discrimination, the Company may require an agreement for a longer term than specified in the applicable Service Classification, may require a contribution in aid of construction, and may establish such minimum charges and facilities charges as may be equitable under the circumstances. (Also see Section 4.05)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.01 Measurement of Electricity Consumption: The Service provided to the Customer will be measured separately for each Point of Delivery by metering. Bills will be based upon the registration of such metering equipment except as may be otherwise provided in this Tariff. Such registration shall be conclusive as measuring the quantity of Service received by the Customer except when the metering equipment fails to register or is determined to be registering outside the limits of accuracy prescribed by the BPU. In some instances the Company may, at its sole discretion, allow for unmetered Service. (Also see Sections 3.15 and 3.16)

3.02 Separate Billing for Each Installation: Service provided through each meter shall be billed separately in accordance with this Tariff. Conjunctive billing, which is the combination of the quantities of energy, demand, or other billing elements of two or more meters or Services into respective single quantities for the purpose of billing as if the bill were for a single meter or Service, will not be permitted except where more than one meter has been installed for Company operating reasons. (Also see Sections 1.02 and 3.15)

3.03 Meter Reading and Billing Period: Unless otherwise specified, the charges for Service are stated on a monthly basis. Meters are read on a regular schedule, as nearly as practicable every 30 days. The term "month" as used in this Tariff, generally means the period between any two consecutive regularly scheduled meter readings. The term "billing period" usually refers to the interval of time elapsing between two consecutive meter readings, but it may mean other time intervals, either actual or estimated, taken or made for the purpose of computing the amount due to the Company from the Customer. Bills to Customers will normally be rendered monthly, but the Company may, in its sole discretion, read meters and render bills generally, or to limited groups of Customers, on other than a monthly basis for either experimental purposes or as a regular procedure, after giving reasonable notice to the affected Customers and to the BPU. In such event the monthly charges stated in the applicable service classification shall be prorated to conform to the new billing period. (See NJAC 14:3-7.4)

3.04 Prorating of Monthly Charges: All bills for periods other than 26 to 35 days inclusive will be computed by prorating the monthly charges provided in the applicable service classifications on the basis of the relationship between the number of days in the billing period and 30 days.

3.05 Estimated Bills: Where the Company has not obtained a reading of the meter it may submit a bill for the minimum charge, or estimate the amount of Service provided and submit an estimated bill. Such bill is subject to adjustment on the basis of the actual Service provided as established by the next actual meter reading, or for any unusual circumstances known to have affected the amount of Service provided.

The Company reserves the right to discontinue Service when a meter reading has not been obtained for eight months or more and after written notice is sent to the customer per NJAC 14:3-7.2. The Company will use all reasonable means to obtain a meter reading before discontinuing Service. (Also see Section 7.03 and NJAC 14:3-3A.1)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.06 Billing Adjustments: An adjustment of charges due to the Company for Services provided by the Company will be made when a meter fails to register within the limits of accuracy prescribed by the BPU in accordance with NJAC 14:3-4.6, or for any other legitimate reason, in which case such adjustment shall not be for a period of more than six years prior to the time the reason for the adjustment became known to the Company. (See NJAC 14:3-4.6)

3.07 Billing of Charges in Tariff: Unless otherwise designated, the charges set forth in this Tariff shall apply to Service rendered on and after the effective date specified in the applicable Service Classification.

3.08 Payment of Bills: Bills for Service provided by the Company are payable when rendered and are due within fifteen days of the mailing date of the bill or as otherwise prescribed by regulation NJAC 14:3-3A.3. They can be paid at any business office of the Company, to any duly authorized collector or collection agency, by mail, or by electronic funds transfer. If a bill is not paid by the date indicated on the bill, the Company, on not less than ten days written notice, may discontinue service to the Customer after 27 days following rendition of the bill or as otherwise prescribed by regulation. (See NJAC 14:3-3A.3)

Whenever a residential Customer advises the Company that the Customer wishes to discuss a deferred payment agreement because of a present inability to pay a total outstanding bill and/or a security deposit, the Company will make a good faith effort to provide the Customer with a reasonable deferred payment agreement. Either prior to or after the discontinuance of service for non-payment, a residential Customer may be required to pay a down payment of not more than 25% of the total outstanding bill due at the time of the agreement. Deferred payment agreements which extend more than two months must be in writing. The Company is not required to offer or enter into more than one deferred payment agreement in a 12-month period, but the Company may, in its sole discretion, elect to offer more than one such agreement in the same 12-month period. If the Customer defaults on any of the terms of the agreements, the Company may discontinue service after providing the Customer with a notice of discontinuance. (See NJAC 14:3-7.7)

A Customer's failure to receive a bill shall not relieve the Customer of any of the Customer's obligations hereunder.

Where a non-residential Customer requests a deferred payment agreement, the agreement shall be limited to a period of no more than three months, and the Customer may be required to make a partial payment at the time of entering into the deferred payment agreement. The amount of the partial payment shall be no more than one half of the amount past due and owing at that time. The existence of a deferred payment agreement does not relieve the Customer of applicable monthly late payment charges. (See Section 3.19)

3.09 Guarantee of Payment: Where the credit of an Applicant for Service is impaired or not established, or where the credit of a Customer has become impaired, a money deposit or other guarantee satisfactory to the Company may be required as security for the payment of bills for Service before the Company will commence or continue Service. If a residential Customer's Service has been terminated for non-payment of bills, the Company may not condition restoration of Service on payment of a deposit unless said deposit had been included as a charge on prior bills, or prior notice to the Customer had been given. (See NJAC 14:3-3.4)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.10 Amount of Credit Deposit: The deposit from the Customer shall be not less than twice the estimated or actual bill for a single billing period at the applicable rate. In the case of a Customer taking Service for less than 30 days, a credit deposit may be required in an amount equal to the estimated bill for such temporary period. The Company will issue a receipt to each Customer making a deposit. (See NJAC 14:3-3.4)

3.11 Interest on Credit Deposit: All money deposits under Section 3.09 shall bear simple interest payable at the rate and in the manner specified under NJAC 14:3-3.5(d). Deposits shall cease to bear interest upon termination of Service.

3.12 Return of Credit Deposit: Upon termination of Service and payment in full of all unpaid bills for Service, the Company will return the deposit plus accrued interest, or will deduct from the deposit and interest all amounts due and return the difference, if any, to the depositor. The Company shall have a reasonable time in which to read meters and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposit. The credit deposit is not a floating credit available to be used by the Customer for the payment of interim bills for service, but the Company may apply the deposit and any accrued interest against any unpaid bills and require the Customer, as a condition on continuing Service, to restore the deposit to an amount, determined in accordance with the principles set forth in Sections 3.09 and 3.10, sufficient to secure the payment of future bills. Residential customer accounts will be reviewed at least once every year and non-residential Customer accounts at least once every two years. Should such review indicate that the Customer has established satisfactory credit with the Company, the credit deposit plus accrued interest, if any, will be returned to the depositor. Such return of a credit deposit shall not serve to waive the Company's right to re-establish the credit deposit as required herein above. The Company may require surrender of the receipt issued when the deposit was made, or in lieu thereof, proof of identity before returning the deposit or any part thereof. (See NJAC 14:3-3.5)

3.13 Final Bill: A customer intending to discontinue Service shall give the Company reasonable notice thereof and arrange for the reading of the meter. Where the Customer is discontinuing all Service, the reading shall be regarded as a final reading and the Company will read the meter within forty-eight hours of receipt of such notice unless a holiday or a weekend intervenes or the Customer desires otherwise. If, because of conditions occasioned by the Customer, or by reason of compliance with the Customer's request, the final reading of the meter must be obtained outside of regular business hours, the Customer will be subject to the service charges specified in the applicable Service Classification within this Tariff.

Whether or not the Customer gives notice of discontinuance, the Customer shall be liable for Service delivered to the premises until the final reading of the meter can be obtained by the Company. Where the Customer is discontinuing all Service, the bill for Service rendered until the final meter reading, plus all other charges due and any applicable minimum charge for the unexpired term of a contract, is due and payable immediately upon presentation. Where the Service in question is unmetered, a final bill shall be rendered upon discontinuance of Service.

Section 3 - Billings, Payments, Credit Deposits & Metering

3.14 Taxes on Contributions in Aid of Construction and Customer Advances or Deposits: Any contribution in aid of construction ("CIAC"), customer advance or deposit, or other like amount received from Customers which shall constitute taxable income as defined by the Internal Revenue Service may be increased to include a payment equal to the applicable current taxes incurred by the Company as a result of receiving such monies, less the net present value of future tax benefits related to the tax depreciation guideline-life applicable to the property constructed with such monies, which for transmission or distribution items shall be taken to be 20 years. The discount rate to be used for such present value calculation will be the Company's last allowed overall rate of return.

3.15 Unmetered Service: Where the Customer's equipment is of such a character and its operation is so conducted that the Customer's use of service at the Point of Delivery is substantially invariable over the period Service is supplied, thus permitting accurate determination of billing quantities by calculation based on the electrical characteristics of such equipment, the Company may omit the installation of metering equipment and, with the consent of the Customer, use the respective quantities, so determined, for billing purposes under the applicable Service Classification. The Customer shall not make any change whatever in the equipment or mode of operation thereof, Service to which is billed in the foregoing manner, without first obtaining the Company's consent in writing. If the Customer changes equipment or mode of operation, any Service to such changed equipment or operation shall be deemed unauthorized use and shall be subject to discontinuance as provided elsewhere in this Tariff.

3.16 Non-measurable Loads: Customers with equipment which creates unusual fluctuations, which cannot be measured by standard metering facilities, shall have the maximum 15-minute demand, monthly KWH, and reactive component calculated for such equipment, and added to any such measured quantities for the customer's remaining load for billing purposes under the applicable Service Classification.

3.17 Equal Payment Plan for Individual Residential Dwelling Units: The Company may, upon request by a residential Full Service Customer, determine a payment plan of twelve equal monthly payments for the Customer. Monthly payments required under this plan may be revised by the Company one time during the payment plan period as rate changes or special conditions warrant. If actual charges are more or less than the estimated amounts, billing adjustments necessary to provide for the payment of the actual charges due for Service rendered under this plan shall be made in the twelfth month of the plan, or in the event the Equal Payment Plan is terminated, on the next bill. The Company may terminate this plan at any time as to any Customer if any monthly bill rendered to such Customer under this plan is unpaid when the next monthly bill is rendered. (See NJAC 14:3-7.5)

3.18 Returned Payment Charge: A charge of $12 will be assessed against a Customer's account when a check or an electronic payment or other form of funds transfer, which has been issued to the Company, is returned by the bank as uncollectible, or otherwise dishonored by the bank from which the funds were drawn.

Section 3 - Billings, Payments, Credit Deposits & Metering

3.19 Monthly Late Payment Charge: Upon the non-receipt of payment for services provided by the Company or an Alternative Electric Supplier by a Customer receiving Service under Service Classifications GS, GST, GP, GT, SVL, MVL, ISL, LED and Rider CEP and receiving a bill for such service rendered by the Company, as opposed to a consolidated bill rendered by an Alternative Electric Supplier, except for State, County, and Municipal Government accounts, a Late Payment Charge at the rate of 1.5% per monthly billing period shall be applied. This charge will be applied to all amounts previously billed, including any unpaid late payment charge amounts applied to previous bills, which are not received by the Company when the next regular bill is calculated. The amount of the Late Payment Charge to be added to the unpaid balance shall be determined by multiplying the unpaid balance by the monthly Late Payment Charge rate of 1.5%. (See NJAC 14:3-7.1)

3.20 Delinquent Charge: For Customers receiving Service under Service Classifications RS, RT, RGT, GS and GST, a field collection charge will be applied for each collection visit made by the Company to the Customer's premises, except Customers who qualify for protection under the standards set forth in the NJAC 14:3-3A.5 as detailed in the Stipulation of Final Settlement (Docket No. ER95120633).

3.21 Summary Billing: Upon a Customer's request and the Company's approval, a Customer with multiple Full Service accounts may receive Summary Billing, in which the billing information for the multiple accounts is reported on a single statement, for the convenience of the Customer. Summary Billing shall not be permitted for any delinquent accounts, and shall be permitted only in those cases where meter reading dates and due dates of the multiple accounts allow for Summary Billing without adversely affecting the timely payment of bills and where summary billing does not have an adverse financial impact on the Company. The Company may, in its sole discretion, discontinue Summary Billing, or charge Customers an additional amount for Summary Billing to offset any actual or potential adverse financial impact on the Company. A single due date for accounts that are billed in summary shall be established by the Company and provided to the Customer. Summary Billing shall not commence unless and until the Customer agrees to the due date established for such Summary Billing.

3.22 Special Billing: The Company shall consider all requests from Customers to deviate from the Company's standard billing practices and procedures, including those described in this Tariff. The Company may, in its sole discretion, agree to provide special billing to a Customer, subject to, a payment by the Customer of all costs associated with the Company providing such special billing.

3.23 Metering: The Company shall maintain, install and operate meters and related equipment as necessary to measure and record the Customer's consumption and usage of all services provided under this Tariff. The Company may, in its sole discretion, install such meters and related equipment (including, but not limited to, telemetering equipment) it deems reasonable and appropriate to provide service to Customers under this Tariff. The Company may, in its sole and exclusive discretion, install such special metering as may be requested by a Customer, subject to the Customer paying all of the Company's material, labor, overheads and administrative and general expenses relating to such facilities.

The Company shall conduct inspections and tests of its meters in accordance with prudent electric practices and as otherwise prescribed by the BPU.

Section 3 - Billings, Payments, Credit Deposits & Metering

3.23 Metering: (Continued)

If requested by the Customer, the Company may, in its sole discretion, elect to provide kilowatt-hour pulses and/or time pulses from the Company's metering equipment. All costs for providing the meter pulses shall be paid by the Customer. If a Customer's consumption of kilowatts and/or kilowatt-hours increases as a result of interruptions or deficiencies in the supply of pulses for any reason, the Company shall not be responsible or liable, for damages or otherwise, for resulting increases in the Customer's bill.

If requested by a Customer, the Company may, in its sole discretion, elect to provide metering to a service location other than what is presently installed or otherwise proposed to be installed by the Company at that location. All costs for special metering facilities provided by the Company, including, but not limited to, all material, labor, overheads and administrative and general expenses, shall be billed to and paid by the Customer.

Section 4 - Supply and Use of Service

4.01 Continuity of Service: The Company will use reasonable diligence to maintain a regular and uninterrupted provision of Service, but should the Service be interrupted, curtailed, suspended, or discontinued by the Company for any of the reasons set forth in Section 7 of these Standard Terms and Conditions, or should the Service be interrupted, curtailed, deficient, defective, or fail by reason of any natural disaster, accident, act of a third party, strike, legal process, governmental interference or by reason of compliance in good faith with any governmental order or directive, notwithstanding that such order or directive subsequently may be held to be invalid, or other causes whatsoever beyond its control, the Company shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure. The Company will not be responsible for any damage or injury arising from the presence or the use of Service provided to the Customer by the Company after it passes from the Company's facilities to the Point of Delivery, unless such damage or injury is caused by the sole negligence or willful misconduct of the Company. Any damage or injury arising from occurrences or circumstances beyond the Company's reasonable control, or from its conformance with standard electric industry system design or operation practices, shall be conclusively deemed not to result from the negligence of the Company. Due to the sensitive nature of computers and other electric and electronically controlled equipment, Customers, especially three-phase Customers, are advised to and should provide protection against such variations in power and voltage supply.

4.02 Temporary Service: Service for a temporary or short term period will be provided and billed under the applicable Service Classification when the Company's available installed facilities are of adequate capacity to render such Service, provided the Customer pays in advance the estimated net cost of installing and removing all facilities provided to furnish such Service. If the total period of temporary Service is less than one month, the total billing for such period shall not be less than the stated monthly minimum of the applicable Service Classification. At the option of the Company, bills for temporary Service may be prorated and rendered at periodic intervals of less than one month and are due and payable upon presentation. The Company's specifications for the Customer's installation are available from the Company upon request.

4.03 Transformation Facilities for Transmission Customers: Where, for the mutual convenience of the Company and Customer, the transformation equipment at a delivery point is utilized by both parties, the Company will provide such facility at a monthly charge of 1.5% of the prorated cost. The prorated cost shall be (1) the product of (a) the highest 15-minute demand (rounded to the next highest 100 KW) established by the Customer on such commonly-used transformation facility since Service was originally established, and (b) the Company's book cost of such commonly-used transformer substation less those items of equipment devoted solely to uses other than supplying the Customer, (2) divided by the maximum capability of the transformation equipment when operating under load conditions. In the event that the transformer bank's maximum capability is altered, either by changes in the transformers, the transformer cooling equipment, or in the characteristics of the Customer's load, item (2) above shall be redetermined to reflect the changed conditions.

Section 4 - Supply and Use of Service

4.04 Emergency Curtailment of Service: The Company may curtail or discontinue the provision of Service to any Customer, upon reasonable notice if possible, in the event it becomes necessary to do so in case of emergencies or in compliance with an order or directive of Federal, State, or municipal authorities. The Company may interrupt Service to any Customer or Customers in an emergency threatening the integrity of its system or to aid in the restoration of Service if, in its sole judgment, such action will alleviate the emergency condition and enable it to continue or restore Service consistent with the public welfare. (Also see Sections 4.01 and 7.02) In the event of an actual or threatened restriction of fuel supplies available to its system or the systems to which it is directly or indirectly connected, the Company may curtail or interrupt Service or reduce voltage to any Customer or Customers if, in its sole judgment, such action will prevent or alleviate the emergency condition. (See NJAC 14:3-3A.1)

4.05 Special Company Facilities: At the Customer's request, or as required, subject to approval by the Company, the Company will furnish and install on its system, special, substitute, or additional facilities to meet the Customer's special or additional requirements or to protect the Company's system from disturbance of standard voltage regulation that otherwise would be caused by the operation of customer's equipment. When the Company furnishes facilities not normally supplied or when the estimated or actual cost of such special substitute or additional facilities exceeds the estimated cost of the standard facilities that normally would be supplied by the Company without special charge, either (a) the Customer shall pay in a manner to be agreed upon a facilities charge annually amounting to 18% of such additional cost, or (b) by mutual agreement the Customer may pay an amount equivalent to such additional cost, plus applicable taxes. However, alternative (a) shall not be available unless the facilities are such as are commonly and usually transferred from place to place for use in the Company's system or are reasonably capable of reuse. The Customer may also be subject to other monthly or special charges in order to meet their special needs.

4.06 Single Source of Energy Supply: No Customer may maintain or operate any source of electric energy on his premises or at his contract location in a manner whereby such source may become interconnected with the Company's facilities without the prior written approval of the Company. Such prior approval may be conditioned, among other things, on the installation and operation by the Customer at the Customer's cost and expense of such switches and/or protective devices as the Company may deem necessary to prevent injury to persons or damage to property of either the customer or the Company. Such approved interconnection may be maintained only at the appropriate rates and charges as provided in this Tariff.

4.07 Changes in Customer's Installation: The Customer, prior to making any material increase or decrease in Connected Load, demand, or other conditions of use of Service or change of purpose, arrangement, or characteristics of electrical equipment, shall notify the Company of such intention so that the Company may determine if any changes in its distribution facilities or in the Point of Delivery will be required in order that safe, adequate, and proper Service may be supplied to the Customer under the proposed changed conditions. Prior to starting any work, the Customer or his agent shall submit for the Company's approval sufficient copies as required of the plans of such proposed installations, together with a list of the principal apparatus to be used. The Company will advise the Customer if any feature of the proposed changed conditions would be incompatible with such Service. (Also see Section 5.06) Such proposed changes in the Customer's Service conditions shall not be made effective until they have been approved by the Company.

Section 4 - Supply and Use of Service

4.08 Customer's Liability to Company: Failure of the Customer to give prior notice of changes in conditions as described in Section 4.07 shall render the Customer responsible and liable for any personal injury and any property damage caused by the changed conditions, including damage to the Company's property and injury to its employees. In those cases where the Customer's bill is based on the connected load, failure to give notice of changes therein will not relieve the Customer from liability for payment of proper charges for Service based upon such changed conditions from the date such change first occurred, nor entitle the Customer to a refund or adjustment if the charges billed exceed the amount that would normally be applicable under the changed conditions.

4.09 Request for Relocation of, or Work on, Company Facilities: When the Company is requested to relocate or work on its facilities and such relocation or work is for the purpose of enabling the Customer to work on or maintain his electrical facilities or building, or perform work or construction safely in the vicinity of Company equipment, the Customer shall pay to the Company, in advance of any relocation or work by the Company, the estimated cost to be incurred by the Company in performing such relocation or work. For work of a routine nature frequently performed within the Company's service area, the Company may specify a flat fee based upon the average costs of performing such work. (Also see Sections 6.04, 6.06, and 6.08)

4.10 Liability for Supply or Use of Electric Service: The Company will not be responsible for the use, care, condition, quality or handling of the Service delivered to the Customer after same passes beyond the point at which the Company's service facilities connect to the Customer's wires and facilities. The Customer shall hold the Company harmless from any claims, suits or liability arising, accruing, or resulting from the supply to, or use of Service by, the Customer.

4.11 Relocation of Meters or Service Equipment: Where meter locations are changed from indoor to outdoor, the Company may permit feeding back from the new meter location to the original Service Entrance. When an existing Service Entrance is to be changed, the old Service shall remain active and properly metered until the old Service is disconnected and the new Service is reconnected. When it is impractical to comply with this requirement, the Company must be contacted and arrangements made to accomplish the changeover. Metered and unmetered conductors will not be permitted in the same conduit or raceway, except in special cases where Company approval has been obtained.

4.12 Liability for Acts of Alternative Electric Suppliers: The Company shall have no liability or responsibility whatsoever to the Customer for any agreement, act or omission of, or in any way related to, the Customer's Alternative Electric Supplier.

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Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Section 5 - Customer's Installation

5.01 General Requirements: The Customer's installation must conform to the Company's specifications and all requirements of municipal and State authorities and regulations set forth in the National Electric Code in effect at the time of such installation. The Company will, however, install and maintain facilities on the Customer's premises at the Customer's cost when the Company determines such installation and maintenance to be necessary or more convenient for the delivery of Service and there is mutual agreement as to the installation and maintenance cost. Where for engineering or operating reasons it is necessary or desirable to install a substation, transformers, capacitors, control, protective or other equipment on the Customer's premises in order to supply the Service required by the Customer, the Customer shall provide a suitable place and housing for such facilities. The Company's specifications for the Customer's installation are available from the Company upon request.

5.02 Service Entrance: The Customer's Service Entrance facilities shall extend from the Point of Delivery specified by the Company to an approved entrance switch cabinet located on the Customer's premises. With the exception of metering equipment and related facilities furnished by the Company, all of the facilities necessary to conduct electricity from the Point of Delivery to the Customer's circuits shall be installed, owned, and maintained by the Customer. The Customer must provide and install an approved service head and assure all fittings used in the Service Entrance provide a water-tight connection. At least three feet of wire must be left for the connection to the Service Drop on all services. (Specifications for service installations will be furnished by the Company upon request.)

5.03 Inspection and Acceptance: The Company may refuse to connect with any Customer's installation or to make additions or alterations to the Company's Service Connection when such installation is not in accordance with the National Electrical Code, or with the Company's requirements, or where a certificate approving such installations has not been issued by an electrical inspection authority certified by the New Jersey Department of Community Affairs for the area in which the installation is located, or by a City or County Inspection Authority having exclusive authority to make electrical inspection in such area. (See NJAC 14:3-8.3(g) and (h))

5.04 Special Customer Facilities: The Customer shall furnish at his own expense any special facilities necessary to meet his particular requirements for Service at other than the standard conditions specified under the provisions of the applicable Service Classification. (Also see Section 5.05)

5.05 Regulation of Power Factor: The Company shall have the right to require the Customer to maintain a power factor in the range of 87% to 100% coincident with the Customer's maximum on-peak monthly demand and to provide, at its sole expense, any corrective equipment necessary in order to do so. The Company may inspect the Customer's installed equipment and/or place instruments on the premises of the Customer in order to determine compliance with this requirement, as deemed appropriate by the Company. The installation by the Company of corrective devices necessary for compliance with this provision, shall, as deemed appropriate by the Company, be billed to the Customer under the provisions of Section 4.05. The Company is under no obligation to serve, or to continue to serve, a Customer who does not maintain a power factor acceptable to the Company. (Also see Sections 5.01 and 5.04)

Section 5 - Customer's Installation

5.06 Change in Point of Delivery: In the event that the Company shall be required by any governmental authority to relocate its distribution facilities or to place any portion of them underground, the Customer shall at its own expense make such changes in its Service Entrance and/or in its underground Service Connection as may be necessary in order to conform to the new Point of Delivery specified by the Company. Any change requested by the Customer in the location of the existing Point of Delivery, if approved by the Company, will be at the expense of the Customer.

5.07 Liability for Customer's Installation: The Company will not be liable for damages to or injuries sustained by the Customer or others, or by the equipment or property of Customer or others, by reason of the condition, character, or operation of the Customer's wiring or equipment, or the wiring or equipment of others.

5.08 Meter Sockets and Current Transformer Cabinets: Upon the Company's designation of a Point of Delivery at which its Service line will terminate, the Customer shall provide, at its sole cost and expense, a place suitable to the Company for the installation of metering and all other electric facilities needed for the provision of electric energy by the Company or an Alternative Electric Supplier. It shall be the Customer's responsibility to furnish, install, and maintain self-contained meter sockets and current transformer cabinets in accordance with Company specifications which are available upon request.

5.09 Restricted Off-Peak Water Heater Specifications: Service supplied under Service Classification RS - Residential Service, Special Provision (a), or Service Classification GS - General Service Secondary, Special Provision (d), must conform to the following requirements as well as any other applicable conditions of Service:

(a) The minimum capacity of the water heater should not be less than 50 gallons.

(b) Should the water heater have two non-inductive heating elements, each shall be controlled by its own thermostat and both shall be electrically interlocked to prevent simultaneous operation, with the upper heating element located to heat the top one-quarter of the tank volume and the lower element located to heat the entire tank.

(c) The upper heating element may be wired to operate during the on-peak as well as off-peak periods, whereas the lower element, or single element (in a one-element water heater), may operate only during the off-peak periods.

(d) The wattage of each heating element shall not be in excess of 30 watts per gallon of tank volume, rounded to the nearest 500 watts.

(e) Service to water heaters will be supplied at single-phase 208 or 240 volts, depending on the voltage available. For the supply of equipment with one tank or a combination of tanks in excess of 250 gallons or in excess of 7500 watts, the Company must be consulted for installation specifications.

Section 5 - Customer's Installation

5.10 Restricted Controlled Water Heating Specifications: Service supplied under Service Classification RS - Residential Service, Special Provision (b), or under Service Classification GS - General Service Secondary, Special Provision (e), must conform to the following requirements as well as any other applicable conditions of Service:

(a) The water heater shall have two non-inductive heating elements, each controlled by its own thermostat and electrically interlocked to prevent simultaneous operation.
(b) The upper heating element shall be located to heat the top one-quarter of the tank volume and the lower element located to heat the entire tank.
(c) The wattage of each element shall not be in excess of 35 watts per gallon of tank volume rounded to the nearest 500 watts for water heater of 40 gallons or more.
(d) Thirty-gallon water heaters may contain either one or two heating elements, with an element size not to exceed 1500 watts.

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Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Section 6 - Company's Equipment on Customer's Premises

6.01 Ownership, Maintenance and Removal: The Company shall furnish, install and maintain the meters, related equipment and facilities necessary for Service unless otherwise stated. All facilities and equipment supplied by the Company shall remain exclusively its property. The Company may remove such facilities and equipment from the premises of the Customer after termination of Service.

6.02 Customer's Responsibility: Under certain circumstances, it may be necessary for the Company to install equipment on the Customer's premises. This equipment may be placed in vaults, manholes, hand-holes, outdoor substations on concrete pads, etc. These Customer-owned facilities must be constructed in accordance with all applicable codes and to the Company's specifications. Prior to starting work, the Customer or his agent shall submit for the Company's approval plans of such proposed installations, together with a list of the principal apparatus to be used. The Customer shall be responsible for the protection and safe-keeping of the facilities and equipment of the Company while on the Customer's premises and shall not permit access thereto except by duly authorized governmental officials and representatives of the Company. The Customer should notify the Company immediately if any question arises as to the authority or credentials of any person claiming to be a governmental official or a Company representative. Any malfunction or defect in the Company's equipment observed by the Customer should be reported to the Company immediately. (See Section 6.04)

6.03 Access to Customer's Premises: The Company shall have the right to construct, operate, modify, replace and/or maintain any and all facilities it deems necessary to render Service to the Customer and adjoining customers upon, over, across and/or under lands owned or controlled by the Customer. The Company shall have the right of reasonable access to all property furnished by the Company, at all reasonable times for the purpose of inspection of any premises incident to the rendering of service, reading meters, or inspecting, testing, or repairing its facilities used in connection with providing the Service, or for the removal of its property. The Company shall have the right to enter upon the lands owned or occupied by the Customer for the purpose of moving, removing, replacing, altering, accessing, servicing or maintaining any structures, fixtures, equipment, instruments, meters or other property owned by the Company, above or beneath such lands, and shall have the right to trim, cut, move, clear or destroy any trees, shrubs, plants or other growth on such lands as necessary to keep or prevent same from endangering or interfering with the Company's structures, fixtures, equipment, instruments, meters or other property, or with the providing of safe, adequate and reliable Service. The Customer shall obtain, or cause to be obtained, all permits needed by the Company for access to the Company's facilities. Access to the Company's facilities shall not be given except to authorized employees of the Company or duly authorized governmental officials. During an alleged diversion of Service, it is the Company's responsibility to obtain access to the Company’s equipment in accordance with NJAC 14:3-3.6 and 6.8. (See Section 7.03)

Section 6 - Company's Equipment on Customer's Premises

6.04 Tampering: In the event it is established that the Company's wires, meters, meter seals, switch boxes, or other equipment (including, but not limited to, revenue protection locks, meters and other devices) on the Customer's premises have been tampered with, the Customer shall be required to bear all of the costs incurred by the Company including, but not limited to, the following: (a) investigations, (b) inspections, (c) costs of prosecution including legal fees, and (d) installation of any protective equipment deemed necessary by the Company. Furthermore, where tampering with the Company's or Customer's facilities results in incorrect measurement of the Service, the Customer shall pay for such Service as the Company may estimate from available information to have been used on the premises but not registered by the Company's meter or meters. Tampering with the Company's facilities is punishable by fine and/or imprisonment under New Jersey law. (See NJAC 14:3-7.8)

6.05 Payment for Repairs or Loss: The Customer shall pay the Company for any damage to or any loss of Company's property located on the Customer's premises caused by the act or negligence of the Customer or his agents, servants, licensees or invitees or due to the Customer's failure to comply with the applicable provisions of this Tariff.

6.06 Service Disconnection and Meter Removal Authorized: A licensed electrician or an electrical contractor, upon notifying the Company, will be authorized to disconnect and permanently reconnect a single-phase secondary overhead service that is 200 amps or less. Disconnections or meter removals performed by persons other than authorized licensed electricians, authorized electrical contractors, or authorized Company personnel are prohibited and shall constitute tampering. (See Sections 6.07 and 6.08)

6.07 Reconnection of Service or Replacement of Meter: The Company shall have sole authority to reconnect a service or replace a meter. However, upon contacting the Company, a licensed electrician or electrical contractor may be authorized to reconnect a service or reinstall the meter upon completion of his work as provided in Section 6.06. (See Section 4.09)

6.08 Sealing of Meters and Devices: It is the practice of the Company to seal all meters. Service Entrance switches, wiring troughs, or cabinets connected ahead of meters or instrument transformers, will be sealed by the Company. When Service is introduced prior to the completion of the wiring, or where Service is discontinued, the Company or its designated agent may seal all Service equipment. No one except an authorized employee of the Company is permitted to remove a Company seal or padlock, except as provided in Section 6.06.

6.09 Power Disturbance Protection Service: The Company shall offer to provide the following to Customers which request power disturbance protection: (a) diagnostic services to identify the probable cause of electrical disturbance, (b) engineering analysis and design to develop a power conditioning solution, (c) electrical system modification and/or power conditioning equipment installation, and (d) maintenance of the power conditioning systems. Charges for such Service shall be not less than the actual cost to provide such Service. The Company shall not be liable for damage or injury arising from the improper use of power disturbance protection/conditioned power service, systems or equipment, or for any costs or damages attributable to injury or the loss of the Customer's business, production or facilities resulting from the failure of power disturbance protection/conditioned power service, systems or equipment.

Section 7 - Suspension or Discontinuance of Service

7.01 Work on Company's Facilities: The Company may, upon reasonable notice when it can be reasonably given, suspend, curtail, or interrupt Service to a Customer for the purpose of making repairs, changes, or improvements to or in any of its facilities either on or off the Customer's premises.

7.02 Compliance with Governmental Orders: The Company may curtail, discontinue, or take appropriate action with respect to Service, either generally or as to a particular Customer, as may be required by compliance in good faith with any governmental order or directive, and shall not be subject to any liability, penalty, or payment, or be liable for direct or consequential damages by reason thereof, notwithstanding that such instruction, order or directive subsequently may be held to be invalid or in error. Verbal or written orders of police, fire, public health, or similar officers, acting in the performance of their duties, shall be deemed to come within the scope of this subsection. (See Sections 4.01 and 4.04)

7.03 Customer Acts or Omissions: The Company may, upon giving reasonable notice to the Customer when it can be reasonably given, suspend or discontinue Service and remove the Company's equipment from the Customer's premises for any of the following acts or omissions:

(a) Non-payment of any valid bill due from the Customer or the Customer's resident spouse for Service furnished by the Company at any present or previous location. However, non-payment for business Service shall not be a reason for discontinuance of residential Service, except in cases of diversion of Service. (See Section 3.08)
(b) Tampering with any of the Company's facilities. (See Section 6.04)
(c) Fraudulent representation or application in relation to the use of Service. (See Section 1.03)
(d) Moving from the premises, unless the Customer has requested the Company to continue Service at the Customer's expense. (See Section 2.06)
(e) Resale, transfer, or delivering any part of the Service supplied by the Company to others without the Company's permission. (See Section 1.05)
(f) Refusal or failure to make or increase an advance payment or credit deposit as provided for in this Tariff. (See Section 3.09)
(g) Refusal or failure to contract for Service when reasonably required by the Company to do so. (See Section 2)
(h) Connecting and operating equipment so as to produce disturbing effects on the Company's system or Service to other Customers. (See Section 1.06)
(i) Refusal or failure to comply with any provisions of this Tariff.
(j) Where, in the Company's opinion, the condition of the Customer's installation presents a hazard to life or property.
(k) Refusal or failure to correct any faulty or hazardous condition of the Customer's installation.
(l) Refusal of reasonable access to Customer's premises for necessary purposes in connection with rendering of Service, including meter installation, reading or testing, or the maintenance or removal of the Company's property.

Failure by the Company to exercise its rights shall not be deemed a waiver thereof. (See NJAC 14:3-3A.1)

Section 7 - Suspension or Discontinuance of Service

7.04 Reconnection of Service: When Service has been discontinued by reason of any act or omission or default of the Customer, the Company will not restore service to the Customer's premises until the Customer has made proper application therefor and has rectified the condition or conditions that caused the discontinuance. It is further required that the Customer shall have paid all amounts due as provided in this Tariff including the Service Charge of the applicable Service Classification to reimburse the Company in part for the cost of special handling of the account and of the special costs associated with the disconnection and reconnection of Service.

Section 8 - Service Connections

8.01 General: This Section governs situations in which the Company's distribution lines and facilities are of adequate capacity to serve the Customer's load and are located adjacent to the Customer's premises. In these situations, the connection between the Company's system and the Customer's installation shall be made by the Company and established in accordance with the provisions of this Section.

8.02 Overhead Service Connection: The Company will install, connect, and maintain at its own cost and expense not more than one Service Drop for each contract location. The Company shall not be required to install a Service Drop where its length would exceed the safe distance over which a single span of Service Drop conductors can be placed.

8.03 Underground Secondary Service Connection (other than a manhole duct system) to Serve an Individual Residential Customer/Applicant: (a) A residential Customer or Applicant electing an underground Service Connection instead of an overhead Service Connection can elect to install such connection at his/her own cost and expense in accordance with the Company's specifications for such construction. At the Customer's option, the Company will install and connect such underground Service Connection, upon the Customer making a non-refundable contribution, as described in (b) below. In either case, the Company will assume ownership and responsibility for maintenance, including replacement when appropriate, at the Company's expense, of the underground Service Connection upon connection to the Company's system (subject to receipt of requisite easements, rights of way or the like, at no cost to the Company). In addition, at the Customer's option, the Company will assume ownership and responsibility for maintenance, including replacement when appropriate, at the Company's expense, of all private residential underground Service Connections installed prior to the date of this tariff sheet (subject to receipt of requisite easements, rights of way or the like, at no cost to the Company). In connection with any Company work performed under this Section 8.03, whether on Company-owned or Customer-owned facilities, the Company must first be granted the right by the Customer to trim or remove vegetation and to remove structures or other obstructions that interfere with such work and the Company will not be responsible for the costs of repair, replacement or restoration thereof.

(b) The non-refundable contribution will be equal to the predetermined unit cost differential of furnishing such facilities underground instead of overhead. If the Customer provides the trench, the underground Service Connection charge will be credited accordingly.

Section 8 - Service Connections

8.04 Underground Distribution Service Connection to Serve a Non-Residential Customer: Where a non-residential Customer or Applicant elects such underground Service Connection instead of an overhead Service Connection, or where an overhead or secondary network system is not available, the Customer or Applicant, or the Company at the Customer or Applicant's discretion, must install such connection at the Customer or Applicant's own cost and expense in accordance with the Company's specifications for such construction. The Service Connection will be made by the Company, and shall be owned and maintained, and when necessary, relocated in accordance with the Company's specifications, by Customer at the Customer's own cost and expense.

8.05 Underground Distribution Service Connection (other than a manhole duct system) in Residential Subdivision: Where distribution circuits have been extended underground pursuant to Tariff Part II, Section 10, the Service Connection shall be installed underground as part of the entire electrical system for the development upon payment of the applicable charges computed in accordance with Appendix A of these Standard Terms and Conditions.

8.06 Conventional Underground Service Connection (Secondary Network System): If a Customer's or Applicant's facility is located in a designated network system, one conventional underground Service Connection to each contract location will be provided by the Company without cost to the Customer which shall terminate at a point not more than 30 feet distant from the curb, measured at right angles to the curb, nearest the point of connection to the Customer's facilities, provided, however, that the Company will not supply a Service Connection in whole or in part under or within a building except that portion extending through the building wall. When the required length of Service Connection exceeds the foregoing, the Customer shall have the option of terminating his facilities at either (1) a splice box acceptable to the Company installed, owned, and maintained by the Customer at a point within the distance limit described above, or (2) at the discretion of the Company, in the nearest available splice box or manhole provided in and as part of the Company's normal underground distribution system. All connections between the Customer's and Company's facilities shall be made by the Company.

Section 9 - General Interconnect Requirements for On-Site Generation

9.01 The following requirements and standards for connection of generating facilities located on Customer's premises to the Company system shall be met to assure the integrity and safe operation of the Company system with no deterioration to the quality and reliability of service to other Customers. The operation of the generation facility should be done in a competent manner, such that the Company system as a whole is protected.

9.02 All small power producers or cogenerators shall make application to the Company for approval to interconnect their facilities with the Company system.

9.03 The Company shall require the following as part of the application:

(a) Plans and specifications of the proposed installation.
(b) Single line diagram and details of the proposed protection schemes.
(c) Instruction manuals for all protective components.
(d) Component specification and internal wiring diagrams of protective components if not provided in instruction manuals.
(e) Generator data required to analyze fault contributions and load current flows including, but not limited to, equivalent impedances and time constants.
(f) All protective equipment's ratings if not provided in instruction manuals.
(g) Evidence of insurance satisfactory to the Company.
(h) An agreement to indemnify and hold harmless the Company from any and all liability or claim thereof for damage to property, including property of the Company and injury or death to persons resulting from or caused by the presence, operation, maintenance or removal of such installation.

9.04 The Company shall within 30 days from the receipt of all required data from the Applicant either approve or reject in writing the application for connection to the Company system. Rejection of an application shall state with specificity the reasons for such rejection. Connection to the Company system will be permitted only upon obtaining the formal approval of the Company. The Company may require the execution of a formal application form and/or interconnection agreement by the customer.

9.05 The installation of the generation facilities must be in compliance with the requirements of the National Electrical Code and all applicable local, State and federal codes or regulations. The installation shall be undertaken and completed in a workmanlike manner, and shall meet or exceed industry acceptance standards of good practice. The provisions of the National Electrical Safety Code and the standards of the Institute of Electrical and Electronics Engineers, National Electrical Manufacturers Association and the American National Standards Institute shall be observed to the extent that they are applicable. Prior to connection, the Company must be provided with evidence that electrical inspection by an authorized inspection agency indicates that the above items were completed in a manner satisfactory to the Company.

Section 9 - General Interconnect Requirements for On-Site Generation

9.06 The generation facility shall have the following characteristics:

(a) Interconnection voltage shall be compatible and consistent with the system to which the Company determines the generation facility is to be connected.
(b) The generation facility shall produce 60 Hertz sinusoidal output compatible with the Company system to which the facility is to be connected.
(c) The generation facility must provide and maintain automatic synchronization with the Company system to which it is to be connected.
(d) The break point between the generation facilities producing single-phase or three-phase output shall be in accordance with existing Company motor specifications or as otherwise specified by the Company.
(e) At no time shall the operation of the facility result in excessive harmonic distortion of the Company wave form. Total harmonic distortion greater than 5% shall be deemed excessive and shall result in disconnection of the facility from the Company system.
(f) The installation of power factor correction ("PFC") capacitors at the facility may be required under conditions to be determined by the Company when necessary to assure the quality and reliability of service to other Customers. The cost of PFC capacitors shall be borne by the Customer.
(g) The cost of supplying and installing 15-minute integrated generation output metering, and any other special facilities or devices occasioned by the generation facility which the Company may deem necessary on its system, such as telemetry and control equipment, shall be borne by the Customer.

9.07 The Customer shall provide automatic disconnecting devices with appropriate control devices which will isolate the facility from the Company system within a time period specified by the Company for, but not necessarily limited to, the following conditions:

(a) A fault on the Customer's equipment.
(b) A fault on the Company system.
(c) A de-energized Company line to which the customer is connected.
(d) An abnormal operating voltage or frequency.
(e) Failure of automatic synchronization with the Company system.
(f) Loss of a phase or improper phase sequence.
(g) Total harmonic content in excess of 5%.
(h) Abnormal power factor.

The devices shall be so designed and constructed to prevent reconnection of the facility to the Company system until the cause of disconnection is corrected.

9.08 The Company shall reserve the right to specify settings of all isolation devices which are part of the generation facility.

Section 9 - General Interconnect Requirements for On-Site Generation

9.09 The Company shall require initial inspection and testing as well as subsequent inspection and testing of the facility's isolation and fault protection systems at the Customer's expense on an annual basis. Maintenance of these systems must be performed and documented by the customer at specified intervals to the satisfaction of the Company. The Company shall reserve the right to disconnect the customer and/or the generation equipment from the Company system for failure to comply with these inspections, testing and maintenance requirements.

9.10 The Customer is solely responsible for providing adequate protection for the equipment located on the Customer's side of the interconnection system. This protection shall include, but not be limited to, negative phase sequence voltage on three-phase systems.

9.11 The Customer shall provide a Company-controlled disconnecting device providing a visible break on the Company side of the interconnection system. The Company shall require that this device accept a Company-provided padlock. The Company may also require manual operation of the device when required. The Company shall require this device to be labeled "Cogeneration Disconnection Switch" and located outside the facility such that 24-hour access is possible.

9.12 The Customer shall agree to grant access to the Company's authorized representative during any reasonable hours to install, inspect and maintain the Company's metering equipment.

9.13 The Customer must satisfy, and shall be subject to, all terms and conditions of the Company's Tariff for Service.

9.14 No wind generator, tower structure or device shall be installed at a location where, in the event of failure, it can fall in such a manner as to contact, land upon, or interfere with any Company lines or equipment.

9.15 The Customer shall maintain or cause to be maintained the generator and its associated structures, wiring and devices in a safe and proper operating condition so that the installation continues to meet all the requirements contained herein.

9.16 When and if any controversy arises as to the interpretation and application of these requirements and standards, the matter may be referred to the BPU for determination.

9.17 The Company reserves the right to modify or replace the Customer's service meter to prevent reverse registration from the customer's generation facility. Customers desiring to sell power to the Company should refer to Rider QFS - Cogeneration and Small Power Production Service.

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Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.01 General Information: Where a line extension is necessary to provide Service to a Customer or Applicant or group of Customers, and where the request is for an extension of Company facilities to serve new customers, or where the request is for an expansion, upgrade, improvement, or other installation of plant and/or facilities by an Applicant, the procedures set forth in this Section 10 shall be utilized as a guide to determine the extent of any refundable deposit or non-refundable contribution, which may be required from the Customer or Applicant pursuant to NJAC 14:3-8. The Company shall not be precluded from entering into a mutually favorable agreement with the Customer or Applicant when it is deemed that a portion of the investment is for purposes of system improvement. This Section 10 does not apply to installation of special facilities or back-up systems which are not normally supplied by the Company. When such facilities or back-up systems are requested by the Customer, Section 4.05 shall be applicable.

For purposes of this Section 10, the following defined terms are exclusively for use in connection with this Section. Other definitions, as provided in Part I of the Company's Tariff for Service, may also be applicable to any Applicant under this Section and, where appropriate, should be used in conjunction with these terms.

The term "Applicant" means a person or an entity that requests Extension Service from the Company. An Applicant may or may not be the End User or Customer of the Company.

The term "Extension Service" refers to the construction or installation of electric distribution plant and/or facilities by the Company used to convey Service from existing or new plant and/or facilities (and includes the new plant and/or facilities themselves) to a structure or property for which the Applicant has requested Service in response to (i) an application for Extension Service from an Applicant to serve new customer(s) and/or (ii) an application for Extension Service requesting expansion, upgrade, improvement, or other installation of plant and/or facilities to serve existing customer(s). The Extension Service begins at existing plant and/or facilities and ends at the point of connection to or with the Service Connection, and includes the meter.

The term "Extension Cost" refers to the cost of construction and installation of the Extension Service based on the Company's "standard least cost design" criteria, using the Company's unitized or actual cost for materials and labor (both internal and external) employed in the design, construction, and/or installation of the Extension Service, including, but not limited to, Service Connection (subject to Section 8), metering-related costs, and including overheads directly attributable to the work, and the loading factors, such as those for mapping and design. Extension Costs may be apportioned based upon load depending on factors such as the Applicant's needs as compared to the Company's need to enhance or improve reliability, or the needs of other Applicant(s) who may be using the same facilities.

The term "refundable deposit" pertains to the non-interest bearing monies, which must be increased in accordance with Part II, Section 3.14 to provide for the associated income tax liability, that the Applicant must advance prior to the start of construction. The entire refundable deposit amount is subject to refund as set forth herein. Any portion of the refundable deposit remaining after the tenth year of service, as provided in this Section 10, is no longer subject to refund, and becomes the property of the Company. In no event shall more than the original refundable deposit be refunded.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.01 General Information: (Continued)

A “non-refundable contribution," which the Applicant must pay in full prior to construction, becomes the property of the Company and is not subject to refund. All non-refundable contributions must be increased in accordance with Part II, Section 3.14 to provide for the associated income tax liability.

The term "distribution revenues" utilized in this Section 10, as defined by the BPU, shall mean the total revenue, plus related sales and use tax, collected by a regulated entity from a Customer, minus basic generation service charges, plus sales and use tax on the basic generation service charges, and, unless included with basic generation service charges, transmission charges derived from Federal Energy Regulatory Commission (FERC) approved transmission charges, plus sales and use tax on the transmission charges, assessed in accordance with the Company’s Tariff for Service. This definition refers to the total amount of Delivery Service charges (which include Sales and Use Tax) from customer(s), as provided in the applicable rate schedule in Part III of the Company’s Tariff for Service.

The term "underground distribution" refers to buried distribution conductors with associated above-grade equipment.

The term "conventional underground" refers to a secondary network installed in a complete manhole and duct system with all equipment below grade level and is generally located in central sections of the more urban communities.

The term “standard least cost design” refers to the Company’s design criteria for an overhead extension of its facilities, which is based upon then-existing Company specifications as contained in the Company’s Construction Standards, Material Specifications, and Distribution Engineering Practices. These standards are developed in compliance with the current edition of the National Electrical Safety Code in order to provide reliable electric service in a cost-effective manner.

The term “alternate design” refers to an Applicant’s request for Extension Service in a particular manner that exceeds the Company’s “standard least cost design” criteria, including, but not limited to, underground requirements and the removal of existing facilities. An example of an “alternate design” requested by an Applicant would be the installation of a pad-mounted transformer adjacent to a parking lot behind a building, rather than at the front corner closest to the Company’s existing distribution circuit. The difference in cost between the “alternate design” and the “standard least cost design” shall, in all cases, be paid in full by the Applicant as a non-refundable contribution.

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300 Madison Avenue, Morristown, NJ 07962-1911

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.02 Rights-of-Way: The Company shall not be required to extend or relocate its facilities for the purpose of rendering Extension Service to Applicants until rights-of-way or easements satisfactory to the Company have been obtained from government agencies and property owners to permit the installation, operation, and maintenance of the Company's lines and facilities. In connection with granting to, or obtaining for, the Company, without charge, such rights-of-way or easements as necessary for the Company's lines and facilities to be placed upon, over, across, or under property as necessary to provide the Extension Service, Applicants requiring Extension Service shall perform all initial vegetation clearance and trimming. The Company shall also be granted the right to trim or remove vegetation and to remove structures or other obstructions that might subsequently interfere with such lines and facilities, the right of access and entry without notice for Company agents and equipment necessary in the exercise of privileges under the grant, and the right to use and extend the Company's lines and facilities, and install additional lines and facilities, as deemed necessary by the Company in order to provide Service to other Customers. Any right-of-way or permit fees, either initial or recurring, or charges in connection with rights-of-way for providing Extension Service to an Applicant, shall be paid for by the Applicant.

10.03 Extension Service to the Boundary of a Subdivision (Residential and Non-Residential): Such an extension shall normally be provided overhead on public right-of-way and/or private property based upon the Company's standard least cost design criteria, but shall not be provided underground on public right-of-way unless required of, or approved by, the Company.

If the Applicant requests Extension Service that exceeds the Company's standard least cost design criteria, and the Company approves the request, the Applicant shall be required to make a non-refundable contribution equal to the additional cost of the alternate design.

The Company may require a refundable deposit of the Extension Cost, prior to construction, to be refunded as provided in Sections 10.04 or 10.05, as applicable.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.04 Extension Service within a Residential Subdivision: Such an extension shall not be provided overhead. It shall be provided underground based upon the Company's underground design criteria, on public right-of-way and/or private property. This Section is applicable only for new, predominantly residential areas where all the applicable provisions of the Standard Terms and Conditions of this Tariff and any applicable provisions of the New Jersey Administrative Code (NJAC) are complied with.

The Applicant shall make a non-refundable contribution for the construction cost differences between the overhead and the underground design in accordance with Appendix A of Part II of this Tariff.

If the Applicant has not obtained sale contracts for at least 20% of the total units, the Company may require a refundable deposit equal to the Extension Cost using the total unitized cost for the equivalent overhead construction.

Any refundable deposit received from the Applicant will be refunded as follows: One year after the first connection of a completed premise occupied by a bona fide owner or a responsible tenant who has entered into a contract with the Company for Service, the Company will refund a sum equal to ten times total actual distribution revenues from all such bona fide owner(s) or responsible tenant(s) during such contract year, up to (but not in excess of) the refundable deposit amount. Refunds in subsequent years, for up to nine additional years after the first year, will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues that was used for calculating the refund in any previous year, from 2) the total actual distribution revenues from all such bona fide owners or responsible tenants during each such subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

10.05 Extension Service to Serve Non-Residential Customers (including within Non-Residential Subdivisions), Multi-unit Residential Apartment Buildings, and Three-Phase Individual Residential Customers: Such an extension will be provided overhead based upon the Company's standard least cost design criteria, but may be provided underground as an alternate design, but shall not be provided underground on public right-of-way, unless required of, or approved by, the Company. When Extension Service is provided underground pursuant to this Section 10.05, the Applicant, or the Company at the Applicant's discretion (and at the Applicant's own cost and expense consistent with Section 10.01), shall provide all trenching and backfill in accordance with the Company's specifications.

If the Applicant requests Extension Service that exceeds the Company's standard least cost design criteria, and the Company approves the request, the Applicant shall be required to make a non-refundable contribution equal to the additional cost of the alternate design.

The Company may require a refundable deposit equal to the Extension Cost. The refundable deposit under this Section 10.05 shall be eligible for refund, up to (but not in excess of) the refundable deposit amount, as follows: At the end of the first year, the Company will refund from the refundable deposit an amount equal to ten times the total actual distribution revenues billed during that period. At the end of each subsequent year, for an additional nine years, a refund will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues that was used for calculating the refund in any previous year, from 2) the total actual distribution revenues billed during each such subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.06 Extension Service to Serve a Single-Phase, Individual Residential Customer: Such an extension shall be provided overhead based upon the Company's standard least cost design criteria, and may be provided underground as an alternate design, but shall not be provided underground on a public right-of-way. When Extension Service is provided underground pursuant to this Section 10.06, the Applicant shall be required to provide all trenching and backfill in accordance with the Company's specifications.

The difference in cost between the alternate design and the Company's standard least cost design shall be paid in full by the Applicant as a non-refundable contribution.

When provided overhead on a public right-of-way, the Extension Service will be provided without charge or deposit requirement. When provided overhead on private property, the Extension Service will be provided without charge when the Extension Cost, based on the distance measured from the property line to the dwelling location, does not exceed ten times the estimated annual distribution revenues. A refundable deposit may be required from the Applicant for any Extension Cost in excess of ten times the estimated annual distribution revenues.

The refundable deposit under this Section 10.06 shall be eligible for refund, up to (but not in excess of) the refundable deposit amount, as follows: At the end of the first year, the Company will refund from the refundable deposit an amount equal to ten times the total actual distribution revenues billed during that period, less the estimated annual distribution revenues (used as the basis for the initial refundable deposit calculation). At the end of each subsequent year, for an additional nine years, a refund will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues used for calculating the refund in any previous year, from 2) the total actual distribution revenues billed during each subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

10.07 Extension Service within Conventional Underground Area: Such an extension for 600 volt systems necessary on public right-of-way shall be installed without charge or deposit requirement. Such extensions shall not be provided on private property or for other than 600 volt systems.

10.08 Extension Service Initiation: The Company shall not commence construction of the Extension Service until (a) it has received and accepted an application for service; (b) the Applicant has completely executed appropriate contracts for Service, including, but not limited to, Extension Service as set forth in this Section 10; (c) the Applicant has paid any and all associated Extension Costs or other charges, whether by way of a refundable deposit or a nonrefundable contribution as applicable; and (d) the Applicant requesting the Extension Service has furnished to the Company satisfactory rights-of-way over, across, through, in and/or on property that are acceptable to the Company and necessary for the construction, maintenance and operation of the Extension Service.

10.09 Grading Requirements: The Applicant shall perform or arrange and pay for all Company-directed rough grading in accordance with the Company's specifications for underground lines and facilities as said specifications shall be modified by the Company from time to time. The Company's specifications are available from the Company upon request.

10.10 Exceptions: No deviations from the Company's standard construction practices shall be permitted without the Company's approval. Any Company-approved deviations from said construction practices shall be at the Applicant's sole expense.

Section 11 – Third Party Supplier Standards

11.01 Tariff Governs: The Company's BPU-approved Third Party Supplier Agreement and Customer Account Services Master Service Agreement will be governed by reference to this Tariff for Service.

11.02 Uniform Agreement: The Company shall offer the same BPU-approved Third Party Supplier Agreement and Customer Account Services Master Service Agreement to all licensed entities that seek to serve as Alternative Electric Suppliers in the Company's service area by providing electric generation service to Customers located therein.

11.03 Procedure for Agreement Modification: Modifications of the Supplier Fees and Charges contained in the Company’s Third Party Supplier Agreement shall be made in accordance with applicable BPU Orders, including the BPU Order dated August 17, 1999 (Docket No. EO97070460). Other modifications to the Company's Third Party Supplier Agreement must be approved by the BPU in accordance with the standards set forth in the aforementioned Order, as follows, or as otherwise directed by the BPU.

The Company shall file a written request for BPU approval of intended modifications (the "Request") with the Board. The date of filing shall be referenced herein as the "Filing Date." A copy of the filing shall simultaneously be provided, by regular mail, facsimile, hand delivery, or electronic means, to the Division of the Ratepayer Advocate, Public Service Electric and Gas, Conectiv, Rockland Electric, and to all BPU-licensed Alternative Electric Suppliers (using a list of addresses for the Alternative Electric Suppliers that shall be maintained by the BPU and made available to the Company). The mode(s) of transmission shall be selected to effectuate actual delivery of the copies within 48 hours of filing with the Board.

Should the Ratepayer Advocate or any BPU-licensed Alternative Electric Supplier wish to contest the Request, the contesting entity must file its reasons for contesting the Request, in writing, with the BPU and simultaneously serve copies thereof upon the Company and the Ratepayer Advocate. This must be done within 17 days of the Filing Date. Service upon the Company shall be made by way of the Company representative who filed the Request.

Within 45 days of the Filing Date, the BPU may issue a Suspension Order stating that the Request requires further study. Such determination would put the Request on hold, pending future action by the Board.

If the BPU does not take action on the Request within 45 days of the Filing Date, the Company may implement the intended modifications, although the BPU retains the authority to make a determination on the Request in the future.

Section 12 – Net Metering Installations

12.01 General: For the purpose of this Section of the Tariff for Service a Customer-generator is an electricity customer such as an industrial, commercial or residential customer that generates electricity using Class 1 renewable resources as defined in NJAC 14:8-1.2 on the customer's side of the meter. Net metering, as defined in Section 12.02 below, provides for the billing or crediting, as applicable, of energy usage by measuring the difference between the amount of electricity delivered by the Company to a Customer-generator, as defined in Section 12.02 below, in a given Billing Month and the electricity delivered by a Customer-generator into the Company distribution system. The Company reserves the right to select and supply the type of meter(s) that will enable the net metering of electricity as described above.

The Customer generator shall be responsible for all interconnection costs as defined in NJAC 14:8-5.7 et seq., which shall be in addition to any other charges applicable to meet service requirements. For customers eligible for Net Metering the term usage as applied in Section 2.05 shall mean net usage as determined by Net Metering. It is the Customer-generator's responsibility to know all of the rules associated with the provision of net metering service.

12.02 Limitations and Qualifications for Net Metering: "Net metering" means a system of metering and billing for electricity in which the Company 1) credits a customer-generator at the full retail rate for each kilowatt-hour produced by a Class 1 renewable energy system installed on the customer-generator's side of the electric revenue meter, up to the total amount of electricity used by that customer-generator during an annualized period determined under NJAC 14:8-4.3 and 2) compensates the customer-generator at the end of the annualized period determined under NJAC 14:8-4.3 for any remaining credits, at a rate equal to the avoided cost of wholesale power. To qualify for Net Metering, a Customer-generator must generate Class 1 renewable energy as defined in NJAC 14:8-1.2. The Company will offer net metering to any customer that generates Class 1 renewable electricity on the customer's side of the meter provided that the generating capacity of the Customer-generator's facility does not exceed the amount of electricity supplied by the Company over an Annualized period (as defined in NJAC 14:8-4.3).

12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)): To qualify for Aggregated Net Metering a customer must be: a state entity, school district, county, county agency, county authority, municipality, municipal agency, or municipal authority that has multiple facilities with metered accounts to be known collectively as the "Aggregated Meters." The Aggregated Meters must be: located within the Company's territory; served under the same rate schedule; all served by either Basic Generation Service or by the same Third Party Supplier; and located within the customer's territorial jurisdiction or, for a State entity, located within 5 miles of one another. One of the Aggregated Meters must operate a Class 1 solar electric power generation system using a net metered account as defined in Section 12.02, Limitations and Qualifications for Net Metering, except for the annualized electric generation capability limitation. The Qualified Customer-Generator must be located on property owned by the customer. The size of the Qualified Customer-Generator for Aggregated Net Metering is defined in Section 12.03.a, Customer-Generator Sizing Qualifications for Aggregated Net Metering.

Section 12 – Net Metering Installations

12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)): (Continued)

a) **Customer-Generator Sizing Qualifications for Aggregated Net Metering:** The annualized electric generation capability of the customer's solar generating system, located at the net metered location cannot exceed the amount of electricity supplied by the electric power supplier or basic generation service provider to all of the Aggregated Meters over an annualized period. The Aggregated Meters used to determine the maximum annualized electric generation capability of the customer's solar generating system may not be used to determine the maximum annualized electric generation capability of other aggregated net metered facilities nor become a Qualified Customer-Generator as defined in Section 12.02, Limitations and Qualifications for Net Metering.

b) **Billing for Aggregated Net Metering**: The Qualified Customer-Generator will be billed as defined in Section 12.06, Net Metering Billing. However, Section 12.06, Net Metering Billing will not apply to the other Aggregated Meters and those meters will continue to be billed at the full retail rate pursuant to the applicable rate schedules.

c) **Incremental Costs Associated with Aggregated Net Metering:** All incremental costs incurred by the Company resulting from the implementation of Aggregated Net Metering shall be recovered from Aggregated Net Metering customers.

12.04 Installation Standards: A Customer-generator shall comply with the requirements of the Company which are set forth in detail in the Application/Agreement Parts 1 and 2 for Level 1 Projects or the Interconnection Application and Agreement for Level 2 or Level 3 Projects both of which are approved by the New Jersey Office of Clean Energy and available at www.firstenergycorp.com. In addition, the Customer-generator shall be responsible for meeting all applicable safety and power quality standards as set forth below.

The Customer-generator's facility shall comply with all applicable safety and power quality standards specified by the National Electrical Code, Institute of Electrical and Electronics Engineers, and accredited testing institutions, such as Underwriters Laboratories. The Customer-generator's facility should be constructed and installed in accordance with the State of New Jersey Uniform Construction Code requirements for electrical installations, UL 1741 and the IEEE Standard 1547. Net Metering systems served by network distribution systems, shall comply with standards established by the Company and approved by the BPU in addition to the aforementioned applicable safety and power quality standards and all other requirements in NJAC 14:8-5.2 et seq.

Section 12 – Net Metering Installations

12.05 Initiation of Service: Prior to interconnecting with the Company's distribution system the Customer-generator is required to provide the Company with an Interconnection Application/Agreement Parts 1 and 2 for Level 1 projects or an Interconnection Application and Agreement for Level 2 or Level 3 Projects and must also pay all appropriate charges as detailed in these applications. Additionally, the Company may, at its option, inspect the interconnection prior to the initiation of Net Metering service.

Initiation of service will become effective on the Customer-generator's first regularly scheduled meter reading date that is at least twenty (20) days after the Customer-generator elects to take service under or to be billed under or in accordance with this provision, by executing an Interconnection Application, but in no case prior to the installation of the necessary meter(s), and shall terminate at a regularly scheduled meter reading date that is at least twenty (20) days following the receipt by the Company of Customer-generator's notification of termination or from the date that the Company determines that the customer-generator is no longer eligible for net metering service pursuant to NJAC 14:8-4.1 et seq.

12.06 Net Metering Billing: In any Billing Month during an Annualized period, where the amount of electricity delivered by the Customer-generator plus any kilowatt-hour credits held over from the previous Billing Month or Billing Months exceeds the electricity supplied by the Customer-generator's electric supplier or basic generation service provider, as applicable, the excess kilowatt-hours shall be credited to the Customer-generator in the next Billing Month during the Annualized period. At the end of the Annualized period, the Customer-generator will be compensated for any remaining credits by the Customer-generator's electric supplier or basic generation service provider, as applicable, at the avoided cost of wholesale power (as defined at NJAC 14:8-4.2).

A Customer-generator shall have a one-time opportunity to select a Billing Month as the start of the Customer-generator's Annualized period. This selection will become effective on the first regularly scheduled meter reading date that is at least twenty (20) days after the Customer-generator notifies the Company of the Customer-generator's selection under the one-time opportunity provided in NJAC 14:8-4.3 (f) – (j).

In the event that a Customer-generator changes suppliers, the electric power supplier or basic generation service provider with whom service is terminating shall treat the end of the service period as if it were the end of the Annualized period and shall compensate the Customer-generator for any remaining credits at the avoided cost of wholesale power.

12.07 Program Availability: The Company may be authorized by the BPU to cease offering net metering whenever the total rated generating capacity owned and operated by Customer-generators on a Statewide basis equals 2.9 percent of total annual kilowatt-hour sales in the State.

Appendix A - Unit Costs of Underground Construction
Single Family Developments

Appendix A - Residential Electric Underground Extensions
The Applicant shall pay the Company the amount determined from the following table:

A. Base Charges	Average Front Footage Per Lot			
1. Single Family	<= 125 Ft	126-225 Ft	226-325 Ft	>= 326Ft
Nonrefundable charge per building lot				
• With Applicant providing all trenching and road crossing conduits	$ 317.00	$ 370.00	$ 424.00	$ 743.00
Refundable deposit based on equivalent overhead construction	$ 648.00	$ 1,296.00	$1,944.00	$3,240.00

2. Lots requiring 1Φ primary extension

Without primary enclosure	$1,412.00
With primary enclosure	$3,553.00

3. Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 KVA, etc. — Charge to be based on differential cost according to unit costs specified in Exhibits I through III

B. Additional Charges

1. Street Lights

16 foot fiberglass pole with standard colonial post top luminaire	$ 196.00
16 foot fiberglass pole with ornate colonial post top luminaire	$ 1,036.00
30 foot fiberglass pole with cobra head luminaire on 6 foot bracket	$ 919.00
12 foot 9 inch ornate fiberglass pole with ornate colonial post top luminaire	$ 2,216.00
12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire	$ 2,579.00

2. Multi-Phase Construction — $1.13 per added phase per foot

3. Pavement cutting and restoration, rock removal, blasting, difficult digging, and special backfill — At actual low bid cost with option of Applicant to contract for as limited by NJAC

4. Alternate Service Location Charge	<= 125 Ft	126-150 Ft	> 150 Ft
With Applicant trenching (Applicant provides 4” PVC conduits)	$ 781.00	$ 966.00	not applicable

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit I - Unit Costs of Underground Construction
Single-Phase 15 kV

	Item	Unit	Total Cost
1.	Trenching – sole use	per foot	$ 18.10*
2.	Primary cable 1/0 aluminum	per foot	3.09
3.	Secondary cable 3/0 aluminum	per foot	2.26
	350 MCM aluminum	per foot	4.28
	500 MCM aluminum	per foot	6.32
	750 MCM aluminum	per foot	9.53
4.	Service - 200 amp and below	per foot	2.26
	50 feet complete	each	593.35
5.	Primary termination - branch	each	1,186.67
6.	Primary junction enclosure - branch	each	2,141.74
7.	Secondary enclosure	each	461.91
8.	Conduit - 3 inch PVC	per foot	2.71
	Conduit – 4 inch PVC	per foot	3.78
9.	Street light cable - # 12 cu. duplex	per foot	2.27
10.	Transformers - including fiberglass pad		
	25 kVa – single-phase	each	2,372.27
	50 kVa – single-phase	each	2,712.84
	75 kVa – single-phase	each	3,134.72
	100 kVa – single-phase	each	3,507.62
	167 kVa – single-phase	each	4,212.86
	25 kVa – single-phase Dual Voltage	each	2,657.30
	50 kVa – single-phase Dual Voltage	each	3,100.08
	75 kVa – single-phase Dual Voltage	each	4,027.74
11.	Street light poles		
	16 foot post top fiberglass pole	each	414.78
	30 foot fiberglass pole	each	933.78
	12 foot 9 inch ornate fiberglass pole	each	1,594.42
12.	Street light luminaire – cobra head	each	475.66
13.	Post top luminaire		
	50, 70, 100 & 150 watt colonial style	each	270.92
	70 & 100 watt ornate colonial style	each	1,111.68
	70 & 100 watt ornate acorn style	each	1,475.19
14.	Primary splice – # 2 aluminum	each	133.85

* Joint trench calculation: 0.5 x 18.10 = $9.05

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit II - Unit Costs of Underground Construction
Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Primary cable – three-phase main feeder	per foot	$ 20.63
2.	Secondary cable - 4-wire 350 MCM aluminum	per foot	7.21
3.	Service cable - 4-wire 350 MCM aluminum	per foot	7.62
4.	Primary termination - main		
	# 2 aluminum three-phase	each	2,711.97
	1000 MCM aluminum three-phase	each	3,979.00
5.	Primary junction - main	each	3,866.48
6.	Primary switch - main		
	PMH-9	each	24,893.62
	PMH-10	each	23,973.64
	PMH-11	each	25,170.07
	PMH-12	each	29,774.23
7.	Conduit - 5 inch PVC	per foot	5.01
	- 6 inch PVC	per foot	5.77
8.	Transformers - including concrete pad		
	75 kVa three-phase	each	5,371.11
	150 kVa three-phase	each	6,860.58
	300 kVa three-phase	each	8,264.49
	500 kVa three-phase	each	10,688.83
9.	Primary splice – 15 kV three-phase cable	each	340.30

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit III - Unit Costs of Overhead Construction
Single and Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Pole line (including 40 foot poles, anchors & guys)	per foot	$ 5.34*
2.	Primary wire		
	Single-phase – branch	per foot	1.96
	Three-phase – main	per foot	9.82
3.	Primary wire - neutral	per foot	1.85
4.	Secondary cable		
	Three-wire	per foot	4.07
	Four-wire	per foot	6.60
5.	Service		
	Single-phase	each	196.00
	Single–phase - 200 amp and below	per foot	2.00
	Three-phase – up to 200 amp	per foot	3.09
	Three-phase – over 200 amp	per foot	5.20
6.	Transformers		
	25 kVa – single-phase	each	1,358.02
	50 kVa – single-phase	each	1,715.76
	75 kVa – single-phase	each	2,471.51
	100 kVa – single-phase	each	2,693.43
	167 kVa – single-phase	each	3,625.21
	3- 25 kVa – three-phase	each	3,657.43
	3- 50 kVa – three-phase	each	4,730.65
	3- 75 kVa – three-phase	each	6,994.46
	3-100 kVa – three-phase	each	7,660.22
	3-167 kVa – three-phase	each	10,455.56
7.	Street light luminaire	each	490.13

* Pole line cost to be used = $5.34 / 2 = $2.67

Note: All charges are subject to taxes as provided in Section 3.14.

TARIFF for SERVICE

Part III

Service Classifications and Riders

Issued: December 12, 2016 Effective: January 1, 2017

Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER16040383 and ET14101270 dated December 12, 2016

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

PART III
SERVICE CLASSIFICATIONS AND RIDERS
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PART III
SERVICE CLASSIFICATIONS AND RIDERS
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Service Classification RS
Residential Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RS is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RT. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.008758** per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $2.78** per month
Supplemental Customer Charge: $1.45 per month Off-Peak/Controlled Water Heating

2) **Distribution Charge:**

June through September:
$0.015108 per KWH for the first 600 KWH (except Water Heating)
$0.059743 per KWH for all KWH over 600 KWH (except Water Heating)

October through May:
$0.024749 per KWH for all KWH (except Water Heating)

Water Heating Service:
$0.016517 per KWH for all KWH for Off-Peak Water Heating
$0.021756 per KWH for all KWH for Controlled Water Heating

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300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification RS
Residential Service

3) Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)
$0.000114 per KWH for all KWH including Off-Peak/Controlled Water Heating

4) Societal Benefits Charge (Rider SBC):
$0.007013 per KWH for all KWH including Off-Peak/Controlled Water Heating

5) RGGI Recovery Charge (Rider RRC):
See Rider RRC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

6) Storm Recovery Charge (Rider SRC):
See Rider SRC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

7) Zero Emission Certificate Recovery Charge (Rider ZEC):
See Rider ZEC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

8) Tax Act Adjustment (Rider TAA):
See Rider TAA for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, a contract of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

Service Classification RS
Residential Service

SPECIAL PROVISIONS:

(a) Restricted Off-Peak Water Heating Service: Locations currently receiving service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications, shall be billed a Supplemental Customer Charge, and shall have the KWH used during the off-peak hours of 8 PM to 8 AM Eastern Standard Time measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.09)

(b) Restricted Controlled Water Heating Service: Locations currently receiving service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications and have the operation of both upper and lower elements restricted by Company control devices to the hours of 11 PM to 4 PM Eastern Standard Time, shall be billed a Supplemental Customer Charge, and shall have the KWH used during those hours measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.10)

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification RT
Residential Time-of-Day Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RT is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RS. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT): All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.008758** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $5.19** per month
Solar Water Heating Credit: $1.30 per month

2) **Distribution Charge:**
$0.046298 per KWH for all KWH on-peak for June through September
$0.034008 per KWH for all KWH on-peak for October through May
$0.021627 per KWH for all KWH off-peak

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
$0.000114 per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
$0.007013 per KWH for all KWH on-peak and off-peak

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

Service Classification RT
Residential Time-of-Day Service

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM Eastern Standard Time, Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high density areas. The off-peak hours will not, however, be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, contracts of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

SPECIAL PROVISION: Solar Water Heating Systems: For customers who install a solar water heating system with electric backup, the monthly Customer Charge shall be reduced by the credit provided above.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

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Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification RGT
Residential Geothermal & Heat Pump Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RGT is available for residential customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, who have one of the following types of electric space heating systems as the primary source of heat for such structure or unit and which system meets the corresponding energy efficiency criterion:

Geothermal Systems with Energy Efficiency Ratio (EER) of 13.0 or greater;
Heat Pump Systems with Seasonal Energy Efficiency Ratio (SEER) of 11.0 or greater, and a Heating Season Performance Factor (HSPF) which meets the then current Federal HSPF standards;
Room Unit Heat Pump Systems with Energy Efficiency Ratio (EER) of 9.5 or greater.

Service Classification RGT is not available for customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, which have an electric resistance heating system as the primary source of space heating for such structure or unit.

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing) (formerly Rider BGS-FP)

2) Transmission Charge:
$0.008758 per KWH for all KWH on-peak and off-peak for June through September
$0.008758 per KWH for all KWH for October through May

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) Customer Charge: $5.19 per month

2) Distribution Charge:

June through September:
$0.046298 per KWH for all KWH on-peak
$0.021627 per KWH for all KWH off-peak

October through May:
$0.024749 per KWH for all KWH

Service Classification RGT
Residential Geothermal & Heat Pump Service

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
$0.000114 per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
$0.007013 per KWH for all KWH on-peak and off-peak

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM Eastern Standard Time, Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high-density areas. The off-peak hours will not, however, be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, contracts of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GS
General Service Secondary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GS is available for general service purposes at secondary voltages not included under Service Classifications RS, RT, RGT or GST.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT): All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge:**
$0.008758 per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$ 3.10** per month single-phase
$11.13 per month three-phase

Supplemental Customer Charge: **$ 1.45** per month Off-Peak/Controlled Water Heating
$ 2.54 per month Day/Night Service
$11.57 per month Traffic Signal Service

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 6.63 per maximum KW during June through September, in excess of 10 KW
$ 6.17 per maximum KW during October through May, in excess of 10 KW
$ 3.01 per KW Minimum Charge, in excess of 10 KW

Service Classification GS
General Service Secondary

KWH Charge:

June through September (excluding Water Heating and Traffic Signal Service):

$0.059299 per KWH for all KWH up to 1000 KWH
$0.004743 per KWH for all KWH over 1000 KWH

October through May (excluding Water Heating and Traffic Signal Service):

$0.054868 per KWH for all KWH up to 1000 KWH
$0.004743 per KWH for all KWH over 1000 KWH

Water Heating Service:

$0.016517 per KWH for all KWH Off-Peak Water Heating
$0.021756 per KWH for all KWH Controlled Water Heating

Traffic Signal Service:

$0.012427 per KWH for all KWH

Religious House of Worship Credit:

$0.030231 per KWH for all KWH up to 1000 KWH

3) **Non-utility Generation Charge (Rider NGC):**

$0.000114 per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

4) **Societal Benefits Charge (Rider SBC):**

$0.007013 per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**

See Rider RRC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

7) **Storm Recovery Charge (Rider SRC):**

See Rider SRC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**

See Rider ZEC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

9) **Tax Act Adjustment (Rider TAA):**

See Rider TAA for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

Service Classification GS
General Service Secondary

DETERMINATION OF DEMAND: The KW used for billing purposes shall be the maximum 15-minute integrated kilowatt demand during each billing month calculated to the nearest one-tenth KW. In instances where the Company has determined that the demand will not exceed 10 KW, and has therefore elected to not install a demand meter, the demand shall be considered less than 10 KW for billing purposes. Where Service is rendered under Special Provision (a), the on-peak demand shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours of 8 AM to 8 PM prevailing time, Monday through Friday each billing month, while the off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

Issued: December 12, 2016 **Effective: January 1, 2017**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER16040383 and ET14101270 dated December 12, 2016

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification GS
General Service Secondarv

SPECIAL PROVISIONS:

(a) Day/Night Service: Customers who normally operate in such manner that their maximum demands do not occur during the Company's on-peak period and elect to receive Service under this Special Provision shall have their monthly demand charge under this Service Classification based upon the greater of: (a) the maximum on-peak demand created during the month; or (b) 40 percent of the maximum off-peak demand created during the month. For the monthly KW Minimum Charge calculation, the Customer's demand will be based on the greater of: (a) the maximum on-peak demand created during the current and preceding eleven months; or (b) 40 percent of the maximum off-peak demand created during the current and preceding eleven months (but not less than the Contract Demand). Customers served under this Special Provision shall be billed an additional Supplemental Customer Charge provided above.

(b) Restricted Commercial and Industrial Space Heating Service: Customers served as of February 6, 1979, who have (1) electricity as the sole primary source of energy for space heating the entire structure(s) as well as for lighting, power, cooking, refrigeration, water heating, and similar purposes except for incidental special applications or purposes where electrical energy cannot reasonably be used; (2) the sum of the connected loads for lighting, space heating, cooking, and water heating exceed 50% of the total connected load; and (3) at least 50% of the total electrical load is located in a structure(s) heated by electricity; shall have the monthly KW Minimum Charge calculation modified such that the Customer's demand will be based on the highest demand established in the summer billing months only.

(c) Traffic Signal Service: Customers receiving service for traffic signal installations shall be billed an additional monthly Supplemental Customer Charge and the KWH Charges provided above.

(d) Restricted Off-Peak Water Heating Service: Locations currently receiving Service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications, shall be billed a Supplemental Customer Charge, and shall have the KWH used during the off-peak hours of 8 PM to 8 AM Eastern Standard Time measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.09)

(e) Restricted Controlled Water Heating Service: Locations currently receiving Service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications and have the operation of both upper and lower elements restricted by Company control devices to the hours of 11 PM to 4 PM Eastern Standard Time, shall be billed a Supplemental Customer Charge, and shall have the KWH used during those hours measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.10)

(f) Religious Houses of Worship Service: When electric service is supplied to a customer where the primary use of service is for public religious services and the customer applies for and is eligible for such Service, the customer's monthly Distribution Charge will be subject to a KWH Credit provided above for the first 1000 KWH usage per month. The Customer will be required to sign an Application for Religious Houses of Worship Service certifying eligibility. Upon request by Company, the Customer shall furnish satisfactory proof of eligibility for Service under this Special Provision.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Issued: December 12, 2016 **Effective: January 1, 2017**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER16040383 and ET14101270 dated December 12, 2016

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification GS
General Service Secondary

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification GST
General Service Secondary Time-Of-Day

APPLICABLE TO USE OF SERVICE FOR: Service Classification GST is available for general Service purposes for commercial and industrial customers establishing demands in excess of 750 KW in two consecutive months during the current 24-month period. Customers which were served under this Service Classification as part of its previous experimental implementation may continue such Service until voluntarily transferring to Service Classification GS.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge: $0.008758** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$29.86** per month single-phase
$42.61 per month three-phase

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 7.02 per maximum KW during June through September
$ 6.56 per maximum KW during October through May
$ 3.06 per KW Minimum Charge

KWH Charge:
$0.004661 per KWH for all KWH on-peak
$0.004661 per KWH for all KWH off-peak

Service Classification GST
General Service Secondary Time-Of-Day

3) **Non-utility Generation Charge (Rider NGC):**
$0.000114 per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
$0.007013 per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

9) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

Service Classification GST
General Service Secondary Time-Of-Day

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER16040383 and ET14101270 dated December 12, 2016

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification GST
General Service Secondary Time-Of-Day

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification GP
General Service Primary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GP is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Single or three-phase service at primary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**
2) **Transmission Charge: $0.005721** per KWH for all KWH

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $52.56** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 5.48 per maximum KW during June through September
$ 5.09 per maximum KW during October through May
$ 1.86 per KW Minimum Charge

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.35 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.003358 per KWH for all KWH on-peak and off-peak

3) **Non-utility Generation Charge (Rider NGC):**
$0.000109 per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
$0.007013 per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off peak

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

9) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

Service Classification GP
General Service Primary

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 a.m. to 8 p.m. prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

DISCONNECTION / RECONNECTION CHARGES: Charges for all disconnections and reconnections shall be based upon actual costs. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Issued: December 12, 2016 **Effective: January 1, 2017**

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Service Classification GP
General Service Primary

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification GT
General Service Transmission

APPLICABLE TO USE OF SERVICE FOR: Service Classification GT is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Three-phase service at transmission voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).

2) Transmission Charge: **$0.005015** per KWH for all KWH
$0.001156 per KWH for all KWH High Tension Service

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) Customer Charge: **$225.70** per month

2) Distribution Charge:

KW Charge: (Demand Charge)
$ 3.52 per maximum KW
$ 0.94 per KW High Tension Service Credit
$ 2.34 per KW DOD Service Credit

KW Minimum Charge: (Demand Charge)
$ 1.07 per KW Minimum Charge
$ 0.70 per KW DOD Service Credit
$ 0.45 per KW Minimum Charge Credit

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.34 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.002595 per KWH for all KWH on-peak and off-peak
$0.000921 per KWH High Tension Service Credit
$0.001687 per KWH DOD Service Credit

3) Non-utility Generation Charge (Rider NGC):
$ 0.000107 per KWH for all KWH on-peak and off-peak – excluding High Tension Service
$ 0.000104 per KWH for all KWH on-peak and off-peak – High Tension Service

4) Societal Benefits Charge (Rider SBC):
$0.007013 per KWH for all KWH on-peak and off-peak

Service Classification GT
General Service Transmission

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Storm Recovery Charge (Rider SRC)**:
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

9) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

MINIMUM CHARGE PER MONTH: The monthly KW Charge (Demand Charge) under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand). When the maximum on-peak demand created in the current and preceding eleven months has not exceeded 3% of the maximum off-peak demand created in the current and preceding eleven months, the KW Minimum Charge specified above shall be reduced by the KW Minimum Charge Credit stated above.

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

DISCONNECTION / RECONNECTION CHARGES: Charges for all disconnections and reconnections shall be based upon actual costs. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Service Classification GT
General Service Transmission

RECONNECTIONS WITHIN 12-MONTH PERIOD: (Continued)
Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

SPECIAL PROVISIONS:

(a) Commuter Rail Service: Where service is supplied to traction power accounts for a commuter rail system, such accounts shall be conjunctively billed based upon coincident demands. This Special Provision also modifies the DEFINITION OF ON-PEAK AND OFF-PEAK HOURS for Demand Charge purposes only, such that the following Federal Holidays are considered off-peak the entire day: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. In addition, the periods from 8 AM to 10 AM and from 5 PM to 8 PM prevailing time Monday through Friday shall be considered as off-peak for Demand Charge purposes only. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change.

Where traction power is supplied at high tension (230 KV) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining billing demand.

(b) High Tension Service: Where service is supplied at 230 KV, the determination of KW and KVAR demands shall be modified to refer to 60-minute demands, and the Distribution KW and KWH Charges, except for KW Minimum Charge, shall be reduced by the High Tension Service Credits provided above to reflect the reduced line losses associated with service at this voltage level. Any Customer taking this Special Provision shall not be qualified for Special Provisions (c) and (d) below.

(c) Department of Defense Service: Where service is supplied to the major military installations of the United States Department of Defense at transmission voltages, the Distribution KW Charge, KW Minimum Charge and KWH Charge shall be reduced by the DOD Service Credits provided above.

(d) Closing of GTX Service: Upon the closing of Service Classification GTX effective April 1, 2004, for any GTX customer as of August 1, 2003 where service is supplied at 230 KV, the monthly billing demand shall be the maximum 60-minute integrated kilowatt demand created during all on-peak and off-peak hours of the billing month and the Distribution KW Charge (Demand Charge) shall be $0.35 per KW ($0.37 per KW including SUT). The Distribution KW Minimum Charge, KVAR Charge and KWH Charge provided above shall not apply, and the Non-utility Generation Charge shall be the lesser of (1) $0.000312 per KWH ($0.000333 per KWH including SUT), or (2) the net of NGC – High Tension Service stated above and an NGC Credit of $0.009844 per KWH ($0.010496 per KWH including SUT), but not less than zero, for all KWH usage. Effective May 1, 2018 and for an initial term of 10 years, the Societal Benefits Charge (Rider SBC) shall include only the Demand Side Factor (Rider DSF) charge.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Issued: May 10, 2019 **Effective: May 15, 2019**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. AX18010001 and ER18030226 dated May 8, 2019

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification GT
General Service Transmission

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

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Docket No.ER19010013 dated February 27, 2019

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification OL
Outdoor Lighting Service

RESTRICTION: Mercury vapor (MV) area lighting is no longer available for replacement and shall be removed from service when existing MV area lighting fails.

APPLICABLE TO USE OF SERVICE FOR: Service Classification OL is available for outdoor flood and area lighting service operating on a standard illumination schedule of 4200 hours per year, and installed on existing wood distribution poles where secondary facilities exist. This Service is not available for the lighting of public streets and highways. This Service is also not available where, in the Company's judgment, it may be objectionable to others, or where, having been installed, it is objectionable to others.

CHARACTER OF SERVICE: Sodium vapor (SV) flood lighting, high pressure sodium (HPS) and mercury vapor (MV) area lighting for limited period (dusk to dawn) at nominal 120 volts.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings

Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	HPS Area Lighting	MV Area Lighting	SV Flood Lighting
100	121	42	Not Available	**$ 2.46**	Not Available
175	211	74	Not Available	**$ 2.46**	Not Available
70	99	35	**$10.21**	Not Available	Not Available
100	137	48	**$10.21**	Not Available	Not Available
150	176	62	Not Available	Not Available	**$12.00**
250	293	103	Not Available	Not Available	**$12.60**
400	498	174	Not Available	Not Available	**$12.93**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.000114** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007013** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

Issued: January 30, 2020 **Effective: February 1, 2020**

Filed pursuant to Order of Board of Public Utilities
Docket No. ER19121540 dated January 22, 2020

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification OL
Outdoor Lighting Service

TERM OF CONTRACT: One year for each installation and thereafter on a monthly basis. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, plus 3) any additional monthly facility charges, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer. Restoration of Service to lamps which have been disconnected after the contract term has expired shall require a 5 year contract term to be initialized.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

FACILITIES:

(a) Location of Facilities: Fixtures, lamps, controls, poles, hardware, conductors, and other appurtenances necessary for Service under this Service Classification shall be owned and maintained by the Company and must be located where they can be maintained by the use of the Company's standard mechanized equipment. Should customer desire that Company relocate its outdoor lighting facilities at any time, the relocation expense shall be paid by the customer.

(b) Additional Facilities: The per Billing Month charges for poles, transformers and spans of wire furnished by the Company for Service under this Service Classification prior to February 6, 1979 shall respectively be **$0.67**, **$2.70** and **$0.63** until such time as there is a customer change or those facilities are no longer utilized exclusively for service under this Service Classification, or if those facilities require replacement. New or replacement facilities furnished after that date shall be provided, at the Company's option under a 5-year term of contract, based upon payment of: (1) the following per Billing Monthly charges to be added to the Flat Service Charge: 35 foot pole: **$6.16**; 40 foot pole: **$6.90** Secondary Span: **$3.11;** or (2) a single non-refundable contribution determined under Appendix A (See Tariff Part II) charges when applicable; or otherwise (3) upon payment of specific charges determined under billing work order unitized costs.

(c) Maintenance of Facilities: Maintenance of facilities furnished by the Company under this Service Classification shall be scheduled during the Company's regular business hours upon notification by the customer of the need for such service. Maintenance of facilities at times other than during the Company's regular business hours shall be performed at the expense of the customer.

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment will not be billed. The monthly Fixture Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification SVL
Sodium Vapor Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification SVL is available for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

Sodium vapor conversions of mercury vapor or incandescent street lights shall be scheduled in accordance with the Company's SVL Conversion Program, and may be limited to no more than 5% of the lamps served under this Service Classification at the end of the previous year.

CHARACTER OF SERVICE: Sodium vapor lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings

Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
50	60	21	**$ 5.96**	**$ 1.67**	**$ 0.81**
70	85	30	**$ 5.96**	**$ 1.67**	**$ 0.81**
100	121	42	**$ 5.96**	**$ 1.67**	**$ 0.81**
150	176	62	**$ 5.96**	**$ 1.67**	**$ 0.81**
250	293	103	**$ 7.05**	**$ 1.67**	**$ 0.81**
400	498	174	**$ 7.05**	**$ 1.67**	**$ 0.81**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.000114** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007013** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

Service Classification SVL
Sodium Vapor Street Lighting Service

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:

(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Contribution Fixtures: Contribution Fixtures refer to Company Fixtures for which installation the customer has paid the following Contributed Installation Cost. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company.

Contributed Installation Cost: The Contributed Installation Cost, per fixture, shall be equal to the cost shown on Tariff Part II, Appendix A – Exhibit III, for Street Light Luminaire.

(c) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the current edition of the National Electrical Code, as well as equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(d) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled fixture maintenance or replacements as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Fixture Service is provided for Company Fixtures and Contribution Fixtures only. Customer Fixtures currently being provided Limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at the stated Customer Fixture Charge plus **$0.95** per Billing Month. However, Limited Fixture Service is not available for new Customer Fixture installations.

(e) Street Light Poles: Street Light Poles are defined as poles installed for street lighting purposes which are not "standard wood distribution-type poles". These street light poles are typically used for underground distribution applications, and would include aluminum, laminated wood and fiberglass poles. Street Light Poles are installed only upon payment of a non-refundable contribution determined under Appendix A (See Tariff Part II) charges when applicable, or otherwise under fixed-price billing work order costs. Street Light Poles which have previously been installed at the Company's cost shall be billed at the monthly Street Light Pole Charge set forth in Special Provision (b), or the customer may make a payment equivalent to the current installed cost of a similar pole. Street light poles may be provided on private property roadways and associated parking areas, such as apartment building and townhouse complexes. Wood distribution-type poles typically required for street light installations served from overhead distribution facilities shall be considered as distribution poles rather than street light

Service Classification SVL
Sodium Vapor Street Lighting Service

(Continued) poles. When such poles include the mounting of street lighting fixtures provided under this Service Classification, they shall be considered as "fixture-poles" and will be installed, with their associated street lighting wire, without charge to the customer. "Span-poles", which are installed to carry wire to "fixture-poles", shall be installed with their associated wire only upon payment of a non-refundable contribution determined under Appendix A charges (see Tariff Part II) when applicable, or otherwise under billing work order cost estimates. Both fixture-poles and span-poles are installed only along public roadways, or for the extension of existing street lighting service on municipal or governmental properties.

(f) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

SPECIAL PROVISIONS:
(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment will not be billed. The monthly Fixture Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Street Light Pole Charge: Where the Company has installed, at its cost, a pole other than a wood distribution pole for a lamp fixture, a per Billing Month Pole Charge of **$7.94** shall be added to the Fixture Charge specified. Such charge shall not be applicable to a Street Light Pole which has had its installation cost paid for by the customer.

(c) Reduced Lighting Hours: This Special Provision is restricted to previously installed municipal parking lot lighting where the customer desires that energy for such lighting be conserved by having the Service inoperative for six hours per night and the customer reimburses the Company for the cost of any labor and materials required to provide such time control. The Billing Month KWH for lights under this Special Provision will be reduced based on 2010 annual burning hours. The monthly bill shall be the total of 1) the full monthly Fixture Charge plus 2) the reduced Billing Month KWH times all per KWH charges (BGS Energy and Reconciliation Charges, Transmission Charge, Distribution Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment), plus 3) a reduced lighting hours adjustment equal to the Billing Month KWH difference between the standard illumination schedule and the reduced lighting hours schedule for the light, times the per KWH Distribution Charge.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

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Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification MVL
Mercury Vapor Street Lighting Service

RESTRICTION: Service Classification MVL is in process of elimination and is withdrawn except for the installations of customers receiving Service hereunder on July 21, 1982, and only for the specific premises and class of service of such customer served hereunder on such date.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents. At the option of the Company, Service may also be provided for lighting service on streets, roads or parking areas on municipal or private property where supplied directly from the Company's facilities when such Service is contracted for by the owner or agency operating such property.

CHARACTER OF SERVICE: Mercury vapor lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All charges include Sale and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
100	121	42	**$ 4.16**	**$ 1.58**	**$ 0.80**
175	211	74	**$ 4.16**	**$ 1.58**	**$ 0.80**
250	295	103	**$ 4.16**	**$ 1.58**	**$ 0.80**
400	468	164	**$ 4.51**	**$ 1.58**	**$ 0.80**
700	803	281	**$ 5.46**	**$ 1.58**	**$ 0.80**
1000	1135	397	**$ 5.46**	**$ 1.58**	**$ 0.80**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.000114** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007013** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

Service Classification MVL
Mercury Vapor Street Lighting Service

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:

(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Contribution Fixtures: Contribution Fixtures refer to Company Fixtures for which installation the customer has paid the following Contributed Installation Cost. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company. The per Billing Month charges for Contribution Fixtures shall be discontinued only upon payment of a **$35.57** charge per fixture to cover the cost of removal.

Contributed Installation Cost:	Lamp Wattage	Lamp Wattage	Lamp Wattage
	100, 175, & 250	400	700 & 1000
For currently installed fixture:	**$141.33**	**$159.49**	**$210.97**

(c) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(d) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled fixture maintenance or replacements as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Customer Fixtures currently being provided Limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at an additional cost of **$0.78** per Billing Month.

Service Classification MVL
Mercury Vapor Street Lighting Service

(e) Street Light Poles: Street Light Poles refer to all poles other than wood distribution poles, installed, owned and maintained by the Company for street lighting service. Street Light Poles are provided only upon payment by the customer for the installation cost of such pole. Street Light Poles which have previously been installed at the Company's cost, shall be billed at the per Billing Month Street Light Pole Charge set forth in Special Provision (b), or the customer may make a **$345.22** payment to cover the cost of such previous installation.

(f) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment will not be billed. The monthly Fixture Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Street Light Pole Charge: Where the Company has installed, at its cost, a pole other than a wood distribution pole for a lamp fixture, a per Billing Month Pole Charge of **$7.94** shall be added to the Fixture Charge specified. Such charge shall not be applicable to a Street Light Pole which has had its installation cost paid for by the customer.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification ISL
Incandescent Street Lighting Service

RESTRICTION: Service Classification ISL is in process of elimination and is withdrawn except for the installations of customers currently receiving Service, and except for fire alarm and police box lamps provided under Special Provision (c). The obsolescence of this Service Classification's facilities further dictates that Service be discontinued to any installation that requires the replacement of a fixture, bracket or street light pole.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets or roads where required by city, town, county, State or other principal or public agency or by an incorporated association of local residents.

CHARACTER OF SERVICE: Incandescent lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All Charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings Lamp Wattage	Billing Month KWH *	Company Fixture	Customer Fixture
105	37	**$ 1.76**	**$ 0.80**
205	72	**$ 1.76**	**$ 0.80**
327	114	**$ 1.76**	**$ 0.80**
448	157	**$ 1.76**	**$ 0.80**
690	242	**$ 1.76**	**$ 0.80**
860	301	**$ 1.76**	**$ 0.80**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.000114** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007013** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

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Filed pursuant to Order of Board of Public Utilities
Docket No. ER19121540 dated January 22, 2020
Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification ISL
Incandescent Street Lighting Service

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:
(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service, installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(c) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled lamp and control switch replacement as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Customer fixtures currently being provided limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at the stated Customer Fixture Charge plus **$0.95** per Billing Month.

(d) Street Light Poles: Street Light Poles refer to all poles, other than wood distribution poles, installed, owned and maintained by the Company for street lighting service. Replacement of Street Light Poles shall be provided only upon payment by the customer for the current installation cost of such replacement poles except when occasioned and such cost recoverable by a third party.

(e) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

Service Classification ISL
Incandescent Street Lighting Service

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment will not be billed. The monthly Fixture Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Fire Alarm and Police Box Lamp Charge: 25 watt lamps serviced by the Company and served from existing secondary facilities will be billed a monthly Fixture Charge of **$1.03** and **$0.30** for lamps with individual time controls operated on a standard illumination schedule, and lamps operated 24 hours per day, respectively. Lamps with individual time controls operated on a standard illumination schedule will have a Billing Month KWH of 9 KWH. Lamps operated 24 hours per day will have a Billing Month KWH of 18 KWH. All per KWH charges (BGS Energy and Reconciliation Charges, Transmission Charge, Distribution Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment) will be billed based on the applicable lamp's Billing Month KWH.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Issued: May 10, 2019 **Effective: May 15, 2019**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. AX18010001 and ER18030226 dated May 8, 2019

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification LED
LED Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification LED is available for installation of 12 or more LED (light emitting diode) fixtures per request for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

LED conversions of sodium vapor, mercury vapor or incandescent street lights shall be scheduled at the Company's reasonable discretion.

CHARACTER OF SERVICE: LED lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Lamp Wattage	Type	Lumens	Billing Month KWH*	Company Fixture
50	Cobra Head	4000	18	**$ 6.37**
90	Cobra Head	7000	32	**$ 7.04**
130	Cobra Head	11500	46	**$ 8.38**
260	Cobra Head	24000	91	**$ 10.83**
50	Acorn	2500	18	**$ 15.25**
90	Acorn	5000	32	**$ 15.94**
50	Colonial	2500	18	**$ 8.72**
90	Colonial	5000	32	**$ 12.37**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the lamp wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.000114** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007013** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

TERM OF CONTRACT: Ten years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than ten years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

Issued: January 30, 2020 **Effective: February 1, 2020**

Filed pursuant to Order of Board of Public Utilities
Docket No. ER19121540 dated January 22, 2020

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification LED
LED Street Lighting Service

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

MISCELLANEOUS:
(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Street Light Poles: Street Light Poles are defined as poles installed for street lighting purposes which are not "standard wood distribution-type poles." These street light poles are typically used for underground distribution applications, and would include aluminum, laminated wood and fiberglass poles. Street Light Poles are installed only upon payment of a non-refundable contribution determined under Appendix A (See Tariff Part II) charges when applicable, or otherwise under fixed-price billing work order costs. Street Light Poles which have previously been installed at the Company's cost shall be billed at the monthly Street Light Pole Charge set forth below, or the customer may make a payment equivalent to the current installed cost of a similar pole. Street light poles may be provided on private property roadways and associated parking areas, such as apartment building and townhouse complexes. Wood distribution-type poles typically required for street light installations served from overhead distribution facilities shall be considered as distribution poles rather than street light poles. When such poles include the mounting of street lighting fixtures provided under this Service Classification, they shall be considered as "fixture-poles" and will be installed, with their associated street lighting wire, without charge to the customer. "Span-poles," which are installed to carry wire to "fixture-poles," shall be installed with their associated wire only upon payment of a non-refundable contribution determined under Appendix A charges (see Tariff Part II) when applicable, or otherwise under billing work order cost estimates. Both fixture-poles and span-poles are installed only along public roadways, or for the extension of existing street lighting service on municipal or governmental properties.

(c) Street Light Pole Charge: Where the Company has installed, at its cost, a pole other than a wood distribution pole for a lamp fixture, a per Billing Month Pole Charge of **$7.94** shall be added to the Fixture Charge specified. Such charge shall not be applicable to a Street Light Pole which has had its installation cost paid for by the customer.

(d) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Issued: May 10, 2019 **Effective: May 15, 2019**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. AX18010001 and ER18030226 dated May 8, 2019

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)

Effective June 1, 2015, Rider BGS-FP (Basic Generation Service – Fixed Pricing) is renamed Rider BGS-RSCP to comply with the BPU Order dated November 24, 2014 (Docket No. ER14040370).

AVAILABILITY: Rider BGS-RSCP is available to and provides Basic Generation Service (default service) charges applicable to all KWH usage for Full Service Customers taking service at secondary voltages under Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED, except for GS and GST customers that have a peak load share of 500 KW or greater as of November 1, 2018. Rider BGS-RSCP-eligible GS and GST customers may elect to take default service under Rider BGS-CIEP no later than the second business day in January of each year. Such election will be effective June 1 of that year and Rider BGS-CIEP will remain the customer's default service for the entire 12-month period from June 1 through May 31 of the following year. BGS-RSCP-eligible customers who have elected to take default service under BGS-CIEP may return to BGS-RSCP by notifying the Company no later than the second business day in January of each year. Such notification to return to BGS-RSCP will become effective June 1 of that year.

RATE PER BILLING MONTH: (For service rendered effective June 1, 2019 through May 31, 2020)
1) BGS Energy Charge per KWH: (All charges include Sales and Use Tax as provided in Rider SUT.)

Service Classification	June through September	October through May
RS - first 600 KWH	**$0.071616**	
- all KWH over 600	**$0.080841**	
- all KWH		**$0.080232**
(Excludes off-peak and controlled water heating special provisions)		
RT - all on-peak KWH	**$0.136930**	**$0.136930**
- all off-peak KWH	**$0.049909**	**$0.053700**
RGT - all on-peak KWH	**$0.136930**	
- all off-peak KWH	**$0.049909**	
- all KWH		**$0.080232**
RS and GS Water Heating – all KWH	**$0.086075**	**$0.083786**
(For separately metered off-peak and controlled water heating usage under applicable special provisions)		
GS - all KWH	**$0.080390**	**$0.080390**
(Excludes off-peak and controlled water heating special provisions)		
GST - all on-peak KWH	**$0.133218**	**$0.118373**
- all off-peak KWH	**$0.050620**	**$0.053700**
OL, SVL, MVL, ISL, LED - all KWH	**$0.055592**	**$0.057092**

BGS Energy Charges above reflect costs for energy, generation capacity, ancillary services and related cost.

Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED. Effective September 1, 2019, a RMR surcharge of **$0.000000** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective **September 1, 2019**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

TRAILCO-TEC surcharge of **$0.000234** per KWH
Delmarva-TEC surcharge of **$0.000001** per KWH
ACE-TEC surcharge of **$0.000069** per KWH
PEPCO-TEC surcharge of **$0.000014** per KWH
PPL-TEC surcharge of **$0.000729** per KWH
BG&E-TEC surcharge of **$0.000016** per KWH
PECO-TEC surcharge of **$0.000065** per KWH

Effective **February 1, 2020**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

PSEG-TEC surcharge of **$0.002588** per KWH
VEPCO-TEC surcharge of **$0.000181** per KWH
PATH-TEC surcharge of **($0.000003)** per KWH
AEP-East-TEC surcharge of **$0.000046** per KWH
MAIT-TEC surcharge of **$0.000096** per KWH
EL05-121-TEC surcharge of **$0.000228** per KWH

3) BGS Reconciliation Charge per KWH: $0.001367 (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-ups.

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

AVAILABILITY: Rider BGS-CIEP is available to and provides Basic Generation Service (default service) charges applicable to all Full Service Customers taking service at primary and transmission voltages under Service Classifications GP and GT and any Full Service Customers taking service at secondary voltages under Service Classifications GS and GST that have a peak load share of 500 KW or greater as of November 1, 2018, or that have elected to take BGS-CIEP service no later than the second business day in January of each year. All BGS-CIEP customers remain subject to this Rider for the entire 12-month period from June 1 of any given year through May 31 of the following year.

RATE PER BILLING MONTH:
(For service rendered effective June 1, 2019 through May 31, 2020)

1) BGS Energy Charge per KWH: The sum of actual real-time PJM load weighted average Residual Metered Load Aggregate Locational Marginal Price for JCP&L Transmission Zone and ancillary services of **$0.00600** per KWH, times the Losses Multiplier provided below, times 1.06625 multiplier for Sales and Use Tax as provided in Rider SUT.

Losses Multiplier:	GT – High Tension Service	1.005
	GT	1.027
	GP	1.047
	GST	1.103
	GS	1.103

2) BGS Capacity Charge per KW of Generation Obligation: $0.24601 per KW-day times BGS-CIEP customer's share of the capacity peak load assigned to the JCP&L Transmission Zone by the PJM Interconnection, L.L.C., as adjusted by PJM assigned capacity related factors, times 1.06625 multiplier for Sales and Use Tax as provided in Rider SUT.

3) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications GS, GST, GP and GT. Effective September 1, 2019, a RMR surcharge will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

GT – High Tension Service	**$0.000000**
GT	**$0.000000**
GP	**$0.000000**
GS and GST	**$0.000000**

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

3) BGS Transmission Charge per KWH: (Continued)

Effective **September 1, 2019**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	TRAILCO-TEC	Delmarva-TEC	ACE-TEC
GS and GST	**$0.000234**	**$0.000001**	**$0.000069**
GP	**$0.000151**	**$0.000000**	**$0.000046**
GT	**$0.000133**	**$0.000000**	**$0.000041**
GT – High Tension Service	**$0.000031**	**$0.000000**	**$0.000010**
	PEPCO-TEC	PPL-TEC	BG&E-TEC
GS and GST	**$0.000014**	**$0.000729**	**$0.000016**
GP	**$0.000010**	**$0.000474**	**$0.000011**
GT	**$0.000009**	**$0.000419**	**$0.000010**
GT – High Tension Service	**$0.000002**	**$0.000098**	**$0.000002**
	PECO-TEC		
GS and GST	**$0.000065**		
GP	**$0.000043**		
GT	**$0.000037**		
GT – High Tension Service	**$0.000009**		

Effective **February 1, 2020**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	PSEG-TEC	VEPCO-TEC	PATH-TEC
GS and GST	**$0.002588**	**$0.000181**	**($0.000003)**
GP	**$0.001691**	**$0.000118**	**($0.000002)**
GT	**$0.001482**	**$0.000103**	**($0.000002)**
GT – High Tension Service	**$0.000341**	**$0.000023**	**($0.000000)**
	AEP-East-TEC	MAIT-TEC	EL05-121-TEC
GS and GST	**$0.000046**	**$0.000096**	**$0.000228**
GP	**$0.000030**	**$0.000063**	**$0.000149**
GT	**$0.000027**	**$0.000054**	**$0.000131**
GT – High Tension Service	**$0.000006**	**$0.000013**	**$0.000030**

4) BGS Reconciliation Charge per KWH: ($0.002392) (includes Sales and Use Tax as provided in Rider SUT)
The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-ups.

Rider CIEP – Standby Fee
Commercial Industrial Energy Pricing Standby Fee
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

Effective June 1, 2007, Rider DSSAC (Default Supply Service Availability Charge) is renamed Rider CIEP – Standby Fee to comply with the BPU Order dated December 22, 2006 (Docket No. EO06020119).

APPLICABILITY: Rider CIEP – Standby Fee provides a charge applicable to all KWH usage of all Full Service Customers or Delivery Service Customers taking service under Service Classifications GP and GT and any Full Service Customer or Delivery Service Customer taking service under Service Classifications GS and GST that has a peak load share of 500 KW or greater as of November 1, 2018, or that has elected to take Basic Generation Service-Commercial Industrial Energy Pricing under Rider-CIEP no later than the second business day in January of each year. This charge is applicable for service rendered from June 1, 2019 through May 31, 2020 to recover costs associated with administrating and maintaining the availability of the hourly-priced default Basic Generation Service for these customers.

CIEP – Standby Fee per KWH: $0.000150

(**$0.000160** including Sales and Use Tax as provided in Rider SUT)

Rider NGC
Non-utility Generation Charge

APPLICABILITY: Rider NGC provides a non-utility generation charge ("NGC") applicable to all KWH usage of any Full Service Customer or Delivery Service Customer. Effective September 1, 2004, Rider MTC ("Market Transition Charge") is renamed Rider NGC to comply with the BPU Final Order dated May 17, 2004 (Docket Nos. ER02080506, etc.) that "the MTC shall be discontinued and renamed the NGC" for customer billing purposes.

Effective August 1, 2003, the Company recovers through the MTC charge, the MTC deferred balance which includes: (1) BPU-approved costs incurred during the transition to a competitive retail market and under-recovered during the period from August 1, 1999 through July 31, 2003; and (2) all BPU-approved costs associated with committed supply energy, capacity and ancillary services, net of all revenues from the sale of the committed supply in the wholesale market (Docket Nos. EX01110754 and EX01050303, etc.) Carrying cost shall be computed on a monthly basis at the applicable BPU-approved interest rate on the average net-of-tax over or under-recovered balance of the MTC, compounded annually.
Effective August 1, 2003, the composite MTC Factor shall be $0.011013 per KWH (excluding SUT), which includes the interim recovery of MTC deferred balance as of July 31, 2003, until the BPU's decision on the securitization of the MTC deferred balance.
Effective June 1, 2005, the composite MTC Factor shall be reduced to $0.010614 per KWH (excluding SUT), which includes the anticipation of the savings to be realized from the securitization of a portion of the MTC deferred balance as of July 31, 2003 ("Deferred BGS Transition Costs") pending the BPU approval. By Order dated June 8, 2006, the BPU approved the securitization of Deferred BGS Transition Costs.
Effective December 6, 2006, the composite MTC/NGC Factor shall be $0.015492 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.004878 per KWH.
Effective March 1, 2011, the composite MTC/NGC Factor shall be $0.007687 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.007805 per KWH.
Effective March 1, 2012, the composite MTC/NGC Factor shall be $0.002839 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.004848 per KWH.
Effective February 2, 2015, the composite MTC/NGC Factor shall be $0.003750 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.000911 per KWH.
Effective September 1, 2016, the composite MTC/NGC Factor shall be $0.005012 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.001262 per KWH. By Board Order dated May 31, 2017 (Docket No. ER16101046), the Board approved no change to this Factor for the 2015 NGC Filing.
Effective June 10, 2017, the composite MTC/NGC Factor shall be $0.001527 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.001548 per KWH and the OC-TBC and OC-MTC-Tax associated with the securitization of Oyster Creek at zero rate. By Board Order dated September 17, 2018 (Docket No. ER17030306), the Board approved no change to this Factor for the 2016 NGC Filing.
Effective November 1, 2018, the composite MTC/NGC Factor shall be $0.000451 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.001076 per KWH. By Board Order dated June 12, 2019 (Docket No. ER18090977), the Board approved no change to this Factor for the 2017 NGC Filing.
Effective January 1, 2020, the composite MTC/NGC Factor shall be $0.000105 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.000346 per KWH.

Rider NGC
Non-utility Generation Charge

For billing purposes, the composite MTC/NGC Factor of $0.000105 per KWH, which includes the revised DB-TBC and DB-MTC-Tax associated with the securitization of Deferred BGS Transition Costs, as detailed below, shall be applied to all KWH usage of any Full Service Customer or Delivery Service Customer as follows:

Voltage Adjusted MTC Charges per KWH (renamed NGC Charges per KWH)		Including SUT
Secondary Voltages	**$0.000107**	**$0.000114**
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)		
Primary Voltages	**$0.000102**	**$0.000109**
(Applicable to Service Classification GP)		
Transmission Voltages	**$0.000100**	**$0.000107**
High Tension Service (230 KV)	**$0.000098**	**$0.000104**
(Applicable to Service Classification GT)		

Rider NGC
Non-utility Generation Charge

Securitization of Oyster Creek

On February 6, 2002, the BPU approved and issued a Bondable Stranded Costs Rate Order ("Oyster Creek Rate Order") (Docket No. EF99080615) authorizing the issuance and sale of up to $320 million aggregate principal amount of transition bonds to recover certain bondable stranded costs related to the investment in the Oyster Creek Nuclear Generating Station, the imposition of a non-bypassable Transition Bond Charge ("OC-TBC") for the recovery of such costs and the related Market Transition Charge-Tax ("OC-MTC-Tax). The bondable stranded costs are defined in the Oyster Creek Rate Order and include: (1) the capital reduction costs, (2) the upfront transaction costs and (3) the ongoing transition bond costs.

Effective June 11, 2002, the MTC included an OC-TBC of $0.001921 per KWH and an OC-MTC-Tax of $0.000505 per KWH (or $0.002036 per KWH and $0.000535 per KWH including SUT, respectively). The OC-TBC and OC-MTC-Tax are governed by the provisions of the Oyster Creek Rate Order and are subject to periodic true-ups, at least annually but not more frequently than quarterly, except monthly true-ups are permitted in the last year before the scheduled maturity of the transition bonds and continuing until final maturity, as provided in the Oyster Creek Rate Order.

On February 28, 2017, a true-up letter was filed with the BPU in accordance with the provisions in the Oyster Creek Rate Order. Effective May 1, 2017 through May 6, 2017, the OC-TBC and OC-MTC-Tax shall be $0.001198 per KWH and $0.000739 per KWH, respectively (or $0.001280 per KWH and $0.000790 per KWH including SUT, respectively). Effective May 7, 2017, the OC-TBC and OC-MTC-Tax shall be at zero.

Securitization of Deferred BGS Transition Costs

By Order dated June 8, 2006, the BPU approved and issued a Bondable Stranded Costs Rate Order ("Deferred BGS Transition Costs Rate Order") (Docket No. ER03020133) authorizing the issuance and sale of $182.4 million aggregate principal amount of transition bonds to recover the Company's net of tax deferred basic generation service transition costs incurred during the transition period from August 1, 1999 through July 31, 2003, the imposition of a non-bypassable Transition Bond Charge ("DB-TBC") for the recovery of such costs and the related Market Transition Charge-Tax ("DB-MTC-Tax"). The bondable stranded costs are defined in the Deferred BGS Transition Costs Rate Order and include: (1) the upfront transaction costs and (2) the ongoing transition bond costs.

Effective August 10, 2006, the NGC included a DB-TBC of $0.001230 per KWH and a DB-MTC-Tax of $0.000572 per KWH (or $0.001316 per KWH and $0.000612 per KWH including SUT, respectively). The DB-TBC and DB-MTC-Tax are governed by the provisions of the Deferred BGS Transition Costs Rate Order and are subject to periodic true-ups, at least annually but not more frequently than quarterly, and continuing until final maturity, as provided in the Deferred BGS Transition Costs Rate Order.

On March 22, 2019, a true-up letter was filed with the BPU in accordance with the provisions in the Deferred BGS Transition Costs Rate Order. Effective June 1, 2019, the DB-TBC and DB-MTC-Tax shall be revised to $0.000783 per KWH and $0.000296 per KWH, respectively (or $0.000835 per KWH and $0.000316 per KWH including SUT, respectively).

Rider NGC
Non-utility Generation Charge

St. Lawrence Hydroelectric Power

At the November 9, 2004 agenda meeting, the BPU verbally approved, among other things, the Public Power Association of New Jersey ("PPANJ") as Bargaining Agent for the State of New Jersey to renegotiate with the New York Power Authority ("NYPA"), on the allocation of service tariff capacity and associated energy produced at the St. Lawrence/FDR project (In the Matter of the Allocation of St. Lawrence Hydroelectric Power to the State of New Jersey Docket No. EO04101124).

On December 21, 2004, the PPANJ filed with the BPU the following documents associated with the St. Lawrence Hydroelectric Power matter: 1) Agreement for Electric Service Investor Owned Utility Between the PPANJ and JCP&L, PSE&G, Rockland Electric and Atlantic City Electric Company; 2) Agreement Governing Administration of NYPA Power ("Administration Agreement"); and 3) PPANJ for State of New Jersey Service Tariff Capacity and Associated Energy.

Pursuant to the Administration Agreement, the Company, as Nominal Recipient of the Investor-Owned Electric Utilities' share of St. Lawrence/FDR project, is responsible to deliver and distribute the capacity and associated energy as Basic Generation Service to residential customers as designated by the BPU. In addition, the Company is responsible to distribute to each of the Investor-Owned Electric Utilities the Net Economic Benefits calculated according to the Rate Schedule attached to the Administration Agreement. Each of the Investor-Owned Electric Utilities shall allocate the Net Economic Benefits distributed to it to its residential customers through the Investor-Owned Electric Utility's applicable clause through which it recovers non-utility generation costs, or other appropriate rate mechanism if no such clause exists, in a manner that ensures that such benefits flow exclusively to residential customers.

The Company, in its role as Nominal Recipient of the St. Lawrence/FDR project, advises the Investor-Owned Electric Utilities of their respective allocation of the Net Economic Benefits for the period started January 1, 2018 through December 31, 2018. JCP&L's share of the Net Economic Benefits totaled $297,502.44.

Effective June 1, 2019 through May 31, 2020, a St. Lawrence Hydroelectric Power **credit** of **$0.000032** per KWH **($0.000034** per KWH including SUT) will be combined with the Secondary Voltages Adjusted NGC Charge applicable to Service Classifications RS, RT and RGT. Such combined NGC Charge shall be applied to all KWH usage of any Full Service or Delivery Service residential customers.

Rider SBC
Societal Benefits Charge

APPLICABILITY: Rider SBC provides a charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer. The charges that may be included in calculating the SBC include nuclear plant decommissioning costs (Rider NDC), demand side management costs (Rider DSF), manufactured gas plant remediation costs (Rider RAC), uncollectible costs (Rider UNC), and universal service fund costs (Rider USF), in accordance with the New Jersey Electric Discount and Energy Competition Act. The current SBC includes the following charges per KWH:

		Including SUT
Rider DSF	**$0.003457**	**$0.003686**
Rider NDC	**$0.000000**	**$0.000000**
Rider RAC	**$0.000811**	**$0.000865**
Rider UNC	**$0.000352**	**$0.000375**
Rider USF	**$0.001957**	**$0.002087**

Carrying costs on unamortized balances of demand side management costs, nuclear decommissioning costs, manufactured gas plant remediation costs, uncollectible costs and universal service fund costs shall be calculated in accordance with the terms of Rider DSF, Rider NDC, Rider RAC, Rider UNC and Rider USF, respectively.

Effective November 1, 2019, the SBC shall be applied to all KWH usage for billing purposes as follows:

		Including SUT
Total SBC:	**$0.006577**	**$0.007013**

Beginning January 1, 2011, with the exception of universal service fund costs component, all over- and under-recoveries of individual SBC components are to be applied to under- or over-recoveries of other SBC components as of each December 31.

Rider DSF
Demand Side Factor

APPLICABILITY: Rider DSF provides a charge for costs associated with New Jersey Clean Energy Program. The DSF is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

DSF = $0.003457 per KWH ($0.003686 per KWH including SUT)

Demand Side Factor costs include carrying costs on any unamortized balances of such costs at the applicable interest approved by the BPU in its Final Order dated May 17, 2004 (Dockets Nos. ER02080506, et al.), such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

Rider NDC
Nuclear Decommissioning Costs

APPLICABILITY: Rider NDC provides a charge for Nuclear Decommissioning costs. The NDC is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

NDC = $0.000000 per KWH ($0.000000 per KWH including SUT)

Nuclear Decommissioning costs include carrying costs on any unamortized balances of such costs at the applicable interest rate approved by the BPU in its Final Order dated May 17, 2004 (Docket Nos. ER02080506, et al.). Such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

Rider RAC
Remediation Adjustment Clause

APPLICABILITY: Rider RAC determines a Remediation Adjustment in accordance with the formula set forth below. The factor is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

The calculated RAC rate shall be prepared by the Company and filed with the BPU annually by the end of December with a requested effective date of June 1 of the subsequent year. Rider RAC provides for the recovery of manufactured gas plant remediation costs (net of insurance and other recoveries) over rolling seven year periods, including carrying costs on the unamortized balance. Carrying cost is calculated on a monthly basis at an interest rate equal to the rate on seven-year constant maturity Treasuries, as shown in the Federal Reserve Statistical Release on or closest to January 1 of each year, plus sixty basis points, compounded annually as of January 1 of each year.

CALCULATION OF THE REMEDIATION ADJUSTMENT CLAUSE FACTOR:

1) By using the following formula:

RAC = Recoverable Cost / Sales

2) Where the terms are defined as follows:

RAC = The Remediation Adjustment Clause factor in cents per KWH to be applied to all applicable retail KWH sales.

Recoverable Cost = Manufactured Gas Plant remediation expenses (net of insurance and other recoveries) amortized over rolling seven year periods. The cost includes carrying costs on any unamortized balance of remediation costs, net of associated deferred tax balance, at an annual interest rate stated above.

Sales = The Company's forecasted retail KWH sales.

3) Effective November 1, 2019, the RAC computation is as follows ($ Millions):

RAC = $16.434 / 20,263,615 MWH = $0.000811 per KWH
($0.000865 per KWH including SUT)

Rider UNC
Uncollectible Accounts Charge

APPLICABILITY: Rider UNC provides a charge for costs associated with uncollectible accounts recorded in FERC account 904 (Uncollectible Accounts). The UNC is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

UNC = $0.000352 per KWH ($0.000375 per KWH including SUT)

Uncollectible costs include carrying costs on any unamortized balances of such costs at the applicable interest rate approved by the BPU in its Final Order dated May 17, 2004 (Docket Nos. ER02080506, et al.). Such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

Rider USF
Universal Service Fund Costs Recovery

APPLICABILITY: Rider USF provides a charge for costs associated with the state-mandated Universal Service Fund (“USF”) to assist certain customers as defined by the BPU. The USF is included in the Societal Benefits Charge and is applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

Effective October 1, 2019, the USF provided below consists of an USF rate of $0.001249 per KWH and a Lifeline rate of $0.000708 per KWH ($0.001332 per KWH and $0.000755 per KWH including SUT, respectively), pursuant to the BPU Order dated September 27, 2019 (Docket No. ER19060736).

USF = $0.001957 per KWH ($0.002087 per KWH including SUT)

Universal Service Fund costs shall accrue interest on any over or under recovered balances of such costs at the interest rate based on a two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus sixty basis points, but shall not exceed the Company’s overall rate of return as approved by the BPU. Such interest rate shall be reset each month. The interest calculation shall be based on the net of tax beginning and end average monthly balance, consistent with the methodology in the Board’s Final Order dated May 17, 2004 (Docket No. ER02080506 et al.), accrue monthly with an annual roll-in at the end of each reconciliation period.

Rider QFS
Cogeneration and Small Power Production Service

AVAILABILITY: Rider QFS specifies the conditions under which the Company will purchase electricity from a "Qualifying Facility" ("QF") under Section 210 of the Public Utilities Regulatory Policies Act of 1978. Rider QFS is available to customers taking service under Service Classifications GS, GST, GP and GT. QF installations must conform to, and are responsible for all costs associated with, the Company's General Interconnect Requirements for Customer's Generation, according to any applicable installation specifications. (See Part II, Section 10)

QF INSTALLATIONS WITH MORE THAN 1000 KW GENERATING CAPACITY
Such installations shall negotiate with the Company for specific contract arrangements to determine the price, term and conditions to delivered energy and capacity, where applicable; provided however, that in no event shall payments to the QF installation under this tariff exceed the revenues the Company receives from PJM (or its successor), net of PJM penalties and charges. Such contracts are subject to BPU approval.

QF INSTALLATIONS WITH 1000 KW OR LESS GENERATING CAPACITY

Service Charge: $40.00 monthly

Energy Payment: Based on actual real-time PJM load weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) for the JCP&L Transmission Zone at the time when the QF installation delivers energy to the Company.

Capacity Payment: Deliveries from a QF installation that qualify as a PJM Capacity Resource may receive capacity payments when the installed capacity of the QF installation exceeds 100 kW and meets the reliability criteria set forth in PJM Manual 18 (See www.pjm.com), as it may change from time to time. The Capacity Payment, if and as applicable, will be equal to the capacity revenues that the Company receives from PJM for selling such capacity into the Reliability Pricing Model (RPM) capacity auction prior to delivery, adjusted for all other PJM penalties and charges assessed to the Company by PJM arising from, among other things, non-performance or unavailability of the QF installation. QF installations requesting capacity payments must execute an agreement with the Company authorizing the Company to offer such capacity into the PJM market, including terms and conditions of such sale, and including any required security. Any losses experienced by the Company resulting from a QF installation's failure to perform shall be recovered under its Non-utility Generation Charge.

Energy Payment and Capacity Payment, if any, net of Service Charge, shall be determined monthly on an after-the-fact basis, and made within 90 days of the QF meter reading date.

METERING COSTS: QF customers shall pay all metering equipment and related costs as required by the Company and/or by PJM.

INTERCONNECTION COSTS: QF customers shall pay interconnection costs (see Part II, Section 4.05) and any line extension costs required to interconnect the QF to the Company's facilities.

Rider QFS
Cogeneration and Small Power Production Service

LIMITATION ON ENERGY PURCHASES: The Company may refuse to purchase energy from a QF when:

(a) The Company's distribution or transmission circuits are loaded to capacity and further energy would cause an overload. Such refusal to purchase may occur on an instantaneous basis.

(b) An emergency occurs on that part of the Company's system interconnected with the QF such that there would be no means of delivering the energy to the remainder of the Company's system. Such refusal to purchase may also occur on an instantaneous basis.

(c) Customer has failed to provide documentation of QF certification with F.E.R.C. as required by the Company.

(d) Customer has an account arrearage.

Rider STB
Standby Service
(Applicable to Service Classifications GS, GST, GP and GT)

AVAILABILITY: Rider STB specifies the conditions under which customers with qualifying cogeneration or small power production facilities may obtain Standby Service under this Rider when such facilities are used to meet the customer's load requirements. The terms of this Rider shall not be available in any month, however, when the customer's Generation Availability (GA) for the current month does not exceed 50%.

STANDBY DEMAND CHARGE: The terms of this Rider: (1) modify the Determination of Demand and waive the Minimum Demand Charge of the applicable service classification; and (2) impose a Standby Demand Charge determined in accordance with the following calculations and definitions:

SDC=>[(DR*BD)+(SR*<MM or AG)] or [SR*CD]

Which means that the Standby Demand Charge is equal to the greater of:
(1) DR times BD, plus SR times lesser of MM or AG; or
(2) SR times CD

DEFINITIONS:

BD = Billing Demand KW
= >[MM - AG] or [0]
Which means that the Billing Demand is equal to MM - AG, but not less than zero

MM = Maximum Monthly facility on-peak KW load
Which is the maximum coincident 15-minute on-peak load supplied by the Customer's generation plus (or minus) the load delivered by (or furnished to) the Company.

AG = Annual Average Generation on-peak
= Current and preceding eleven months average of [on-peak KWH produced / (260 hours - SM)]
Which means taking the average of each monthly on-peak Average Generation from the current and preceding eleven months. Average Generation is calculated by taking the monthly on-peak KWH produced / (260 hours – SM)

DR = Demand Rate per KW of applicable service classification

Rider STB
Standby Service
(Applicable to Service Classifications GS, GST, GP and GT)

SR = Standby Rate per KW (including SUT)
= **$3.05** for Service Classifications GS & GST
= **$1.90** for Service Classifications GP
= **$0.91** for Service Classifications GT

CR = Capacity Rating of generation facility

CD = Contract Demand
= <[CR] or [>(estimated MM) or (>MM most recent 12 months)]
Which means that the Contract Demand is equal to the lesser of:
(1) CR; or
(2) the greater of: (a) estimated MM; or (b) highest MM of most recent 12 months

GA = Generation Availability
= AG / CD

SM = Scheduled maintenance hours
Applicable only for customers receiving service under this rider as of February 25, 1993. The number of such hours may be reduced up to the amount of mutually agreed upon scheduled maintenance hours, but are not to exceed the amount actually incurred. A maximum of two 2-week periods may be allowed per year during the billing months of April, May, June, October, November or December and must be scheduled 6-months in advance. Each maintenance period may occur only during a single billing period.

260 hours = Average monthly on-peak hours
= 52 weeks x 5 days x 12 on-peak hours ÷12 months

Issued: May 10, 2019 **Effective: May 15, 2019**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. AX18010001 and ER18030226 dated May 8, 2019

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Rider CEP
Consumer Electronics Protection Service

RESTRICTION: This Rider is closed to new enrollment as of March 3, 1999.

AVAILABILITY: Rider CEP had been available for customers which desire that the Company provide protection from power fluctuations, surges and other power disturbances. Service under this Rider is restricted to service entrance and equipment compatibility.

A single meter socket surge suppression device is necessary on the service entrance supplying power to the premises to protect internal wiring against major power line spikes and surges. Electrical receptacle outlet surge suppressors are available for receptacles within the customer's premise. Such receptacle outlet suppressors provide protection against surges to more sensitive electronics, and are only available when a meter socket surge suppression device is installed. Uninterruptible power supply units are available for use with individual electronic equipment.

MONTHLY CHARGES:	Including SUT	Excluding SUT
Meter socket surge suppression device - single phase:	**$2.93**	**$2.75**
Meter socket surge suppression device - three phase:	**$5.33**	**$5.00**
Electrical receptacle outlet surge suppressor - 2 outlet:	**$0.64**	**$0.60**
Electrical receptacle outlet surge suppressor - 4 outlet:	**$0.80**	**$0.75**
Uninterruptible power supply unit - 0.75 KVA:	**$21.33**	**$20.00**
Uninterruptible power supply unit - 1.00 KVA:	**$26.66**	**$25.00**
Uninterruptible power supply unit - 1.50 KVA:	**$31.99**	**$30.00**

TERM OF CONTRACT:
A one-year term of contract is required, renewable thereafter on a month-to-month basis.

TERMS OF PAYMENT:
Charges applicable under this Rider will be rendered on the customer's bill for electric service. Such bills are due when rendered and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter may become subject to a late payment charge as described in Section 3.19, Part II.

Rider CEP
Consumer Electronics Protection Service

TERMS AND CONDITIONS:

1) The Company will install and remove the meter socket surge suppressor device and deliver the electrical receptacle outlet surge suppressors and/or Uninterruptible power supply equipment to the customer.

2) Customers utilizing CEP service provided under this Rider shall contact the Company in order to arrange the return of such equipment to the Company, upon termination of this Service, in the manner specified by the Company. Customers failing to arrange to return such equipment to the Company, shall be required to pay a charge equivalent to the Company's current replacement cost for such equipment.

3) The Company shall not be liable for any damage or injury arising from the improper use of equipment supplied under this Rider or for any costs or damages attributable to the loss of the customer's business, production or facilities resulting from the failure of such equipment.

4) The Company will provide the applicable manufacturer's warranty associated with the meter socket surge suppressor device and/or electrical receptacle outlet surge suppressor.

5) Disconnection and subsequent reconnection of Consumer Electronics Protection Service at the same location shall be unavailable as of March 3, 1999. However, if a customer transfers service from one location to another location within the Company's service areas, the customer may transfer the CEP service to the new location.

Issued: December 12, 2016 **Effective: January 1, 2017**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER16040383 and ET14101270 dated December 12, 2016

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Rider CBT
Corporation Business Tax

APPLICABILITY: In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), provision for the New Jersey Corporation Business Tax (CBT) as it applies to non-production related revenues has been included in all rate schedules. The energy tax reform statute exempts the following customers from the CBT provision, and when billed to such customers, the rates otherwise applicable under this tariff shall be reduced by the provision for the CBT (and related New Jersey Sales and Use Tax) included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey.

2. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

3. Special contract customers for whom a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

Rider SUT
Sales and Use Tax

APPLICABILITY: In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax ("SUT") has been included in all charges applicable under this tariff by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

A. The energy tax reform statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable under this tariff shall be reduced by the provision for the SUT included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey.

2. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

3. Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

4. Agencies or instrumentalities of the federal government.

5. International organizations of which the United States of America is a member.

B. The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c. 374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

1. A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and
2. A group of two or more persons: (a) each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the "Local Redevelopment and Housing Law," P.L.1992, c.79 (C.40A:12A-1 et seq.); (b) that collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process; (c) are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and (d) collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.
3. A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c. 373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in B.1., B.2. or B.3. above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 et seq.) and P.L.1966, c.30 (C.54:32B-1 et seq.) and the Company has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

Reserved for Future Use

Rider RRC
RGGI Recovery Charge

APPLICABILITY: Rider RRC provides a charge for the costs associated with demand response/energy efficiency/renewable energy programs directed by the BPU as detailed below. The RGGI Recovery Charge (RRC) is applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

For service rendered effective January 1, 2020:

RRC = $0.000000 per KWH ($0.000000 per KWH including SUT)

The above RRC provides recovery for the followings:

Solar Renewable Energy Certificates Financing Program (SREC I & II)
Pursuant to BPU Orders dated March 27, 2009 and September 16, 2009 (Docket No. EO08090840) approving an SREC-based financing program (SREC I), pursuant to BPU Order dated December 18, 2013 (Docket No. EO12080750) approving the SREC II, and pursuant to BPU Order dated December 20, 2019 (Docket No. ER19070806) approving the Stipulation of Settlement, the Company shall include an SREC I & II Rate of $0.000000 per kWh in RRC effective January 1, 2020.

The RRC costs shall accrue interest on any over or under recovered balances of such costs at the interest rate based on a two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus sixty basis points, but shall not exceed the Company’s overall rate of return as approved by the BPU. Such interest rate shall be reset each month. The interest calculation shall be based on the net of tax beginning and end average monthly balance, consistent with the methodology in the Board’s Final Order dated May 17, 2004 (Docket No. ER02080506 et al.), compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

The RRC is subject to annual true-up.

Rider SRC
Storm Recovery Charge

APPLICABILITY: Rider SRC provides a charge for the recovery of the amortization of the deferred O&M costs associated with the 2012 major storm through November 30, 2019. The Storm Recovery Charge (SRC) is applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

SRC = $0.000000 per KWH ($0.000000 per KWH including SUT)

The SRC rate shall include carrying costs on the unamortized balance of the deferred O&M costs associated with the 2012 major storm. Such carrying costs shall be calculated on a monthly basis at an interest rate equal to the rate on seven-year constant maturity Treasuries, as shown in the Federal Reserve Statistical Release on or closest to January 1 of each year, plus sixty basis points, compounded annually as of March 31 of each year.

The calculated SRC rate shall be prepared by the Company and filed with the BPU annually by January 15 with a requested effective date of April 1 of the filing year. The first such filing shall be made by January 15, 2016 with actual and projected data for the 12-month period ending March 31, 2016.

The SRC rate was reduced to zero as of December 1, 2019. The final Rider SRC true-up will be filed by January 31, 2020. Any net ending over/under-recovered balance in the Rider SRC deferred balance will be applied to the largest under-recovered component of the Rider SBC deferred balance.

Rider ZEC
Zero Emission Certificate Recovery Charge

APPLICABILITY: The Zero Emission Certificate Recovery Chare (“Rider ZEC” or “ZEC Charge”) provides a charge for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities (“BPU” or “Board”) as detailed below. The ZEC Charge is applicable to all kWh usage of any Full Service Customer or Delivery Service Customer.

Per KWH		Including SUT
ZEC Charge	$0.004000	$0.004265
ZEC Reconciliation Charge	$0.000000	$0.000000
Total ZEC Charge	**$0.004000**	**$0.004265**

Pursuant to the BPU’s Zero Emission Certificate Charge Order dated November 19, 2018 in Docket No. EO18091002, the Board approved the implementation of a non-bypassable, irrevocable ZEC Charge of $0.004000 per KWH for all customers. The ZEC Charge reflects the emission avoidance benefits of the continued operation of selected nuclear plants as determined in L. 2018, c.16 (the “ZEC Law”). The ZEC Charge has been set at the rate specified in the ZEC Law and may be adjusted periodically by the Board, in accordance with the methodology provided for in the ZEC law.

In accordance with the ZEC Law, the proceeds of the ZEC Charge will be placed in a separate account, which amount the Company may use for general corporate purposes, with interest applied at the Company’s short-term borrowing rate as calculated each month, and will be used solely to purchase ZECs and to reimburse the Board for its reasonable, verifiable costs incurred to implement the ZEC program. Refunds will be provided to the customers served under each of the Company’s rate schedules in proportion to the ZEC Charge revenues contributed by the rate schedule.

Rider TAA
Tax Act Adjustment

APPLICABILITY: Rider TAA provides a credit resulting from the amortization and reconciliation of certain Excess Deferred Income Taxes ("EDIT"), including applicable carrying charges related to the impact of the Federal Tax Cuts and Jobs Act of 2017 ("Tax Act") on the Company's rates.

Effective **May 15, 2019**, the following TAA credits, including one time bill credit, (including Sales and Use Tax as provided in Rider SUT) will be applicable to all KWH usage of any Full Service Customer or Delivery Service Customer under Service Classification:

RS	**$0.006389 per KWH**
RT/RGT	**$0.006103 per KWH**
GS	**$0.005116 per KWH**
GST	**$0.003950 per KWH**
GP	**$0.002782 per KWH**
GT	**$0.001632 per KWH**
Lighting	**$0.027344 per KWH**

(includes OL, SVL, MVL, ISL and LED)

Effective **June 15, 2019**, the following TAA credits (including Sales and Use Tax as provided in Rider SUT) will be applicable to all KWH usage of any Full Service Customer or Delivery Service Customer under Service Classification:

RS	**$0.000310 per KWH**
RT/RGT	**$0.000307 per KWH**
GS	**$0.000274 per KWH**
GST	**$0.000213 per KWH**
GP	**$0.000154 per KWH**
GT	**$0.000093 per KWH**
Lighting	**$0.001567 per KWH**

(includes OL, SVL, MVL, ISL and LED)

Carrying Charges: Interest should not accrue on the outstanding net unprotected EDIT liability. No interest charges apply to over or under-recovered balances.

Exhibit JC - 12

Schedule YP - 5

Proposed Tariff

Parts I, II and III

TARIFF for SERVICE

Part I

General Information

Part II

Standard Terms and Conditions

Issued: Effective:

Filed pursuant to Order of Board of Public Utilities
Docket No. Dated

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

PART I
GENERAL INFORMATION
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General Information

A - Service Tariff: This tariff for Service ("Tariff") of Jersey Central Power & Light Company, ("Company"), is filed with the Board of Public Utilities of New Jersey ("BPU") pursuant to NJAC 14:3-1.3. The Standard Terms and Conditions set forth in Part II of this Tariff state the conditions under which Service is rendered, and govern the Company's provision of Full Service, Delivery Service and/or other Services to the extent applicable. The Service Classifications and Riders contained in Part III of this Tariff state the basis for computing the charges to Customers for Service. Except where specifically modified by written contract, all applicable provisions of this Tariff constitute, or are a part of, each service contract, express or implied, and both the Customer and the Company shall be bound thereby.

B - Revision of Tariff: The Company may at any time, and in any manner permitted by law and the applicable rules and regulations of the BPU, supplement, terminate, change, or modify this Tariff or any part thereof.

C - Exchange of Information: The Company will, at the Customer's request, explain the provisions of its Tariff and inform the Customer as to the conditions under which Service can be obtained from the Company's system. It is the responsibility of the Customer or his agent, before making his initial electrical installation or planning material changes in an existing installation, to obtain from the Company information regarding the characteristics of available Service, its designation of the point of attachment of the service connection and meter location, and such other information as may be necessary to assure that the Customer's installation will be compatible with the facilities and Service the Company will supply.

D - Statements by Agents: No representative of the Company has authority to modify any provision contained in this Tariff or bind the Company by any promise or representation contrary thereto.

E - Agreements and Contracts: Standard agreements to provide Service shall be in accordance with Parts II and III of this Tariff. As a condition for establishing, continuing, or resuming the provision of Service in a situation where the Company incurs or will incur greater than normal investment cost or operating expense in order to meet the Customer's special or unusual Service requirements, or to protect the Company's system from undue disturbance of voltage regulation or other adverse effects, and in order to avoid undue discrimination, the Company may require an agreement for a longer term than specified in the applicable Service Classification, may require a contribution in aid of construction and may establish such minimum charges and facilities charges as may be equitable under the circumstances.

General Information

F – Definitions: The following terms are herein defined for general reference to assist in their application in Parts II and III of this Tariff.

(1) Alternative Electric Supplier: Any person, corporation or other entity, other than the Company, that has applied for and received an electric power supplier license from the BPU.

(2) Applicant: Any person, corporation or other entity that (a) desires to receive from the Company electric generation or any other Service provided for in this Tariff, (b) complies completely with all Company requirements for obtaining electric generation or any other Service provided for in this Tariff, (c) has filed and is awaiting Company approval of its application for Service, and (d) is not yet actually receiving from the Company any Service provided for in this Tariff. An Applicant shall become a Customer for purposes of this Tariff only after it actually starts receiving the applicable Service from the Company under this Tariff.

(3) Beneficiary: The person, corporation or the entity financially benefiting from the service.

(4) Billing Month: Generally, that calendar month in which the majority of the Company's meters are read for the purpose of establishing the electric service usage of Customers for their prior 26 to 35 day period.

(5) Connected Load: The sum of the input ratings of all electric-using devices located on the Customer's premises and which are or can be, by the insertion of a fuse, closing of a switch, or any similar method, connected simultaneously to the Company's Service. Although the manufacturer's nameplate rating may be used to determine the input rating of any particular device, the Company may instead determine the input rating of any device by test.

(6) Contract Capacity: That electrical capacity which the Customer specifies is needed to supply the Customer's requirements for Service and which the Company agrees to furnish through either Full Service or Delivery Service.

(7) Contract Location: Each metering point shall be considered a contract location and shall be metered and billed under a separate service contract. In cases where unmetered service is provided, the Point of Delivery shall be considered a contract location.

(8) Customer: Any person, partnership, association, corporation, or agency of municipal, county, state, or federal government receiving any Service rendered by the Company under this Tariff at a Contract Location. The term "Customer" shall also include Applicant when, in the Company's opinion, the specific provision of this Tariff was intended to be so inclusive. Any customer receiving Delivery Service shall simultaneously be a customer of an Alternative Electric Supplier.

(9) Delivery Service: The provision of electric distribution and other services by the Company to Customers under this Tariff who purchase their electric generation service from Alternative Electric Suppliers.

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(10) End User: A person who receives, uses or consumes service. An end user may or may not be a customer as defined herein.

(11) Full Service: The provision of electric distribution and other services by the Company to Customers under this Tariff who purchase their electric generation service from the Company.

(12) Line Extension: This term applies to those overhead or underground facilities for the distribution or transmission of electrical energy to serve new Customers or the enlarged load of existing Customers which are constructed by the Company as a specific project (a) on a public highway and/or (b) on a right-of-way over private or public land to serve one or more Customers. Such an extension may be an addition to and/or upgrade of existing facilities or a new installation of facilities. A line extension originates at the pole or point at which it is connected to the existing facilities or where such upgraded facilities are required and it extends to and includes (a) the most remote pole or point from which a "Service Drop" or "Underground Service Connection" is installed, or (b) to the point at which a "Service Lateral" originates.

(13) Point of Delivery: The point at which the Customer receives Service and from which point inward, with respect to the premises served, the Customer assumes responsibility and liability for the presence or use of electricity in the Customer's installation.

(14) Residence: A structure or portion of a structure intended for use as sleeping quarters by a person or persons, and containing cooking and sanitary facilities.

Auxiliary Residential Purposes: Electric loads used on the premises in conjunction with the operation, use, and maintenance of an individual Residence. Such loads may include yard lighting, swimming pool pumps and heaters, saunas, driveway heaters, household workshops, yard maintenance equipment, and garages or outbuildings when used in conjunction with the operation, use, or maintenance of the Residence.

Multiple Residential Structure: A structure containing more than one Residence and having no direct access between them except from the outside or a common hall.

Group Residential Structure: A structure containing a Residence and five or more sleeping quarters intended for rental purposes, and not qualifying as a Multiple Residential Structure.

Individual Residential Structure: A structure containing a Residence and not qualifying as a Multiple Residential Structure or a Group Residential Structure.

Incidental Non-Residential Purposes: Non-Residential loads totaling 10 kW or less and which are less than 30% of the Residential and/or Auxiliary Residential connected load it is metered with**.**

Non-Residential Purposes: Electric loads which do not qualify under "residential purposes" or "auxiliary residential purposes." Such loads shall include but are not limited to, ceramic kilns, electric welders, greenhouses, and loads used for farming, business, professional, avocation, or animal housing purposes.

General Information

(15) Service: The term "Service" (generally upper case), as used in this Tariff, references any electricity, or access to electricity, that is provided by the Company pursuant to this Tariff, or anything related to the provision of electricity, or access to electricity, provided or rendered by the Company pursuant to this Tariff. Note that the word "service" (generally lower case) is also used from time to time in this Tariff to reference services rendered by entities other than the Company (such as Alternative Electric Suppliers). The distinction between the Company's Services and other entities' services is apparent from the context, and the use of upper and lower case is intended to aid the reader in taking note of the distinction.

(16) Service Connection: The conductors and equipment for delivering Service from the Company's supply system to the service entrance on the customer's premises. If overhead, such Service Connection, also known as a "Service Drop," terminates at a fixture or fixtures installed on the Customer's building or structure at a location designated by the Company which will provide the required clearance of the Service Drop conductors with respect to intervening objects or surfaces. An underground Service Connection is the equivalent of the overhead Service Connection and terminates either at the Customer's over-current protective device on the inside of the first foundation wall adjacent to the street on which the Company's mains are situated or at the meter base installed as part of the “Service Entrance”. If the Company's primary or transmission delivery system is directly connected to the Customer's facilities, such as through transformation or circuit breaking facilities which constitute the service connection, the Point of Delivery shall be the point of connection between the Customer's facilities and the Company's facilities, which is usually identified in a written contract that provides for such direct connection. In other instances, the Point of Delivery is as specified in the definition of "Service Entrance."

(17) Service Drop: A Company-owned overhead Service Connection.

(18) Service Entrance or Entrance Facilities: In general, the conductors or accessory equipment by which electricity is carried from the Service Connection to the supply side of the devices protecting the Customer's circuits. If the Service Entrance is owned by the Customer, it is referred to as "Customer's Entrance Facilities" and the Point of Delivery is the junction of the Service Connection conductors with the Service Entrance. If the Service Entrance is owned by the Company, it is referred to as "Company's Service Entrance" and the Point of Delivery is at the supply side of the devices protecting the Customer's circuits. The metering devices are not included as part of the Service Entrance**.**

(19) Service Lateral: The electrical facilities constituting a branch from the Company's system, installed on private property to serve a single Customer. A Service Lateral may be either overhead or underground. If overhead, the Service Lateral originates at the pole or point at which connection is made to the existing system or line extension and extends to the pole or other aerial support where the Service Drop originates. When a secondary underground Service Lateral is owned, installed, and maintained by the Customer, it shall consist of the specified conduit and cable between its connection with the Company's system and the premises where the Service is to be used. A non-secondary overhead or underground Service Lateral may provide a circuit connection to Company-owned or Customer-owned transformers set in a vault or on a pad on the Customer's premises.

General Information

(20) Standby Service: Service that the Customer may receive or may request that the Company furnish in the event of a breakdown, shutdown, failure, or other impairment of a generator on the Customer's premises, from which the Customer normally receives all or a portion of his energy requirements.

(21) Summary Billing: A Service whereby the Company will add together the charges for multiple Full Service accounts maintained by one Customer and provide the Customer with a single bill.

(22) Tampering: Tampering shall mean connecting or causing to be connected by wire or any other device with the wires, cables or conductors of the Company, or connecting, disconnecting or shunting the meters, cables, conductors or other equipment of the Company, without the Company's permission. (See Part II, Sections 5.03, 6.04, 6.05, 6.06, 6.07, 6.08 and 7.03) (See N.J.S.A. 2C:20-8)

General Information

G - Municipalities Served: The following list designates those municipalities in which the Company serves the public through its distribution facilities.

BURLINGTON COUNTY
Chesterfield Twp.
New Hanover Twp.
North Hanover Twp.
Pemberton Boro
Pemberton Twp.
Southhampton Twp.
Springfield Twp.
Woodland Twp.
Wrightstown Boro

ESSEX COUNTY
Livingston Twp.
Maplewood Twp.
Millburn Twp.

HUNTERDON COUNTY
Alexandria Twp.
Bethlehem Twp.
Bloomsbury Boro
Califon Boro
Clinton, Town of
Clinton Twp.
Delaware Twp.
East Amwell Twp.
Flemington Boro
Franklin Twp.
Frenchtown Boro
Glen Gardner Boro
Hampton Boro
High Bridge Boro
Holland Twp.
Kingwood Twp.
Lambertville, City of
Lebanon Boro
Lebanon Twp.
Milford Boro
Raritan Twp.
Readington Twp.
Stockton Boro
Tewksbury Twp.
Union Twp.
West Amwell Twp.

MERCER COUNTY
East Windsor Twp.
Hightstown Boro
Hopewell Twp.
Washington Twp.
West Windsor Twp.

MIDDLESEX COUNTY
Cranbury Twp.
East Brunswick Twp.
Helmetta Boro
Jamesburg Boro
Monroe Twp.
Old Bridge Twp.
Sayreville Boro
South Amboy, City of
South Brunswick Twp.
Spotswood Boro

MONMOUTH COUNTY
Aberdeen Twp.
Allenhurst Boro
Asbury Park, City of
Atlantic Highlands Boro
Avon-by-the Sea Boro
Belmar Boro
Bradley Beach Boro
Brielle Boro
Colts Neck Twp.
Deal Boro
Eatontown Boro
Englishtown Boro
Fair Haven Boro
Farmingdale Boro
Freehold Boro
Freehold Twp.
Hazlet Twp.
Highlands Boro
Holmdel Twp.
Howell Twp.
Interlaken Boro
Keansburg Boro
Keyport Boro

MONMOUTH COUNTY (Continued)
Lake Como Boro
Little Silver Boro
Loch Arbour, Village of
Long Branch, City of
Manalapan Twp.
Manasquan Boro
Marlboro Twp.
Matawan Boro
Middletown Twp.
Millstone Twp.
Monmouth Beach Boro
Neptune City Boro
Neptune Twp.
Oceanport Boro
Ocean Twp.
Red Bank Boro
Roosevelt Boro
Rumson Boro
Sea Bright Boro
Sea Girt Boro
Shrewsbury Boro
Shrewsbury Twp.
Spring Lake Boro
Spring Lake Heights Boro
Tinton Falls Boro
Union Beach Boro
Upper Freehold Twp.
Wall Twp.
West Long Branch Boro

MORRIS COUNTY
Boonton, Town of
Boonton Twp.
Butler Boro
Chatham Boro
Chatham Twp.
Chester Boro
Chester Twp.
Denville Twp.
Dover, Town of
East Hanover Twp.

General Information

MORRIS COUNTY (Continued)
Florham Park Boro
Hanover Twp.
Harding Twp.
Jefferson Twp.
Kinnelon Boro
Lincoln Park Boro
Long Hill Twp.
Madison Boro
Mendham Boro
Mendham Twp.
Mine Hill Twp.
Montville Twp.
Morris Twp.
Morristown, Town of
Morris Plans Boro
Mountain Lakes Boro
Mt. Arlington Boro
Mt. Olive Twp.
Netcong Boro
Parsippany-Troy Hills Twp.
Pequannock Twp.
Randolph Twp.
Riverdale Boro
Rockaway Boro
Rockaway Twp
Roxbury Twp.
Victory Gardens Boro
Washington Twp.
Wharton Boro

OCEAN COUNTY
Barnegat Twp.
Bay Head Boro
Beachwood Boro
Berkeley Twp.
Brick Twp.
Dover Twp.
Island Heights Boro
Jackson Twp.
Lacey Twp.
Lakehurst Boro
Lakewood Twp.
Lavallette Boro
Manchester Twp.

OCEAN COUNTY (Continued)
Mantoloking Boro
Ocean Twp.
Ocean Gate Boro
Pine Beach Boro
Plumsted Twp.
Point Pleasant Boro
Point Pleasant Beach Boro
Seaside Heights Boro
Seaside Park Boro
South Toms River

PASSAIC COUNTY
Bloomingdale Boro
Pompton Lakes Boro
Ringwood Boro
Wanaque Boro
Wayne Twp.
West Milford Twp.

SOMERSET COUNTY
Bedminster Twp.
Bernards Twp.
Bernardsville Boro
Branchburg Twp.
Bridgewater Twp.
Far Hills Boro
Green Brook Twp.
Hillsborough Twp.
Peapack-Gladstone Boro
Warren Twp.
Watchung Boro

SUSSEX COUNTY
Andover Boro
Andover Twp.
Branchville Boro
Byram Twp.
Frankford Twp.
Franklin Boro
Fredon Twp.
Green Twp.
Hamburg Boro
Hampton Twp.
Hardyston Twp.

SUSSEX COUNTY (Continued)
Hopatcong Boro
Lafayette Twp.
Montague Twp.
Newton, Town of
Ogdensburg Boro
Sandyston Twp.
Sparta Twp.
Stanhope Boro
Stillwater Twp.
Sussex Boro
Vernon Twp.
Wallpack Twp.
Wantage Twp.

UNION COUNTY
Berkeley Heights Twp.
Mountainside Boro
New Providence Boro
Springfield Twp.
Summit, City of

WARREN COUNTY
Allamuchy Twp.
Alpha Boro
Belvidere, Town of
Blairstown Twp.
Franklin Twp.
Frelinghuysen Twp.
Greenwich Twp.
Hackettstown, Town of
Hardwick Twp.
Harmony Twp.
Hope Twp.
Independence Twp.
Knowlton Twp.
Liberty Twp.
Lopatcong Twp.
Mansfield Twp.
Oxford Twp.
Phillipsburg, Town of
Pohatcong Twp.
Washington Boro
Washington Twp.
White Twp

General Information

H – Customer Contact Information:

Emergency / Power Outage Reporting	1-888-544-4877
General Customer Service	1-800-662-3115
Payment Options	1-800-962-0383
Telecommunications Relay Service (TRS) for the Hearing Impaired	711
Morristown General Office 300 Madison Avenue, Morristown, NJ 07962-1911	1-973-401-8200

Customer Billing Questions or Complaints
JCP&L 76 S. Main Street, A-RPC, Akron, OH 44308-1890

Website:
http://www.firstenergycorp.com

Northern Region Business Offices:

Morristown	300 Madison Avenue, Morristown, NJ 07962	**ALL**
Hopatcong	175 Center Street, Landing, NJ 07850	**TELEPHONE**
Phillipsburg	400 Lincoln Street, Phillipsburg, NJ 08865	**INQUIRIES**
		PLEASE USE
Central Region Business Offices:		**CUSTOMER**
Allenhurst	300 Main Street, Allenhurst, NJ 07711	**CONTACT**
Toms River	25 Adafre Avenue, Toms River, NJ 08753	**INFORMATION**
Old Bridge	1345 Englishtown Road, Old Bridge, NJ 08857	**ABOVE**

PART II
STANDARD TERMS AND CONDITIONS
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STANDARD TERMS AND CONDITIONS – TABLE OF CONTENTS

Section 1 - Service Availability

NOTE: Unless specifically stated otherwise, Part II of the Company's Tariff (Standard Terms and Conditions) generally describes the responsibilities of and obligations between Customers and the Company. Specific standards governing the relationship between Customers and the Alternative Electric Supplier and between the Alternative Electric Supplier and the Company have been set forth by the BPU and are noted with references to such BPU Order(s) where applicable to the Company's Tariff.

1.01 Characteristics of Service: The standard electrical supply service provided by the Company is alternating current with a nominal frequency of 60 hertz. Not all types of service listed below are available at all locations, and service voltages other than secondary may be specified by the Company under special conditions such as may relate to the location, size, or type of load. The Company may specify the voltage, phase, and minimum and maximum load that it will supply at any particular voltage. The Company will furnish transformation facilities for secondary service up to a maximum of 300 KVA pole-mounted or 2500 KVA pad-mounted per contract location. Contract locations requiring in excess of these limits may, at the Company's discretion, be provided untransformed service, in which case the customer shall install, own, operate, and maintain the necessary transformation and associated facilities, except metering, in accordance with Company service requirements. Subject to the foregoing limitations, the types of service available with their nominal voltages are:

Secondary Service:		
Single-phase	2 wire	120 volts
Single-phase	3 wire	120/240 volts
Single-phase	3 wire	120/208Y volts
Three-phase	4 wire	120/240 volts
Three-phase	4 wire	120/208Y volts
Three-phase	4 wire	277/480Y volts
Primary Service:		
Single-phase	2 wire	2400 volts
Single-phase	2 wire	4800 volts
Three-phase	3 wire	2400 volts
Three-phase	4 wire	2400/4160Y volts
Three-phase	3 wire	4800 volts
Single-phase	2 wire	7200 volts
Three-phase	4 wire	7200/12470Y volts
Three-phase	4 wire	7620/13200Y volts
Three-phase	3 wire	13200 volts
Three-phase	4 wire	19900/34500Y volts
Transmission Service:		
Three-phase	3 wire	34500 volts
Three-phase	3 wire	115000 volts
Three-phase	3 wire	230000 volts

The Company must always be consulted regarding the type of Service to be supplied.

Section 1 - Service Availability

1.02 Single Point of Delivery: The Company will designate the Point of Delivery and meter location. Service under a particular Service Classification will be supplied to each building or contract location through only one set of Service Connection conductors and metering equipment, except where the Service Classification may require otherwise or where, for economy, engineering, or operating considerations or by reason of applicable codes or governmental regulations, the installation of more than one Service Connection is necessary. Such duplicate or auxiliary delivery sources shall be furnished by separate contract under the applicable Service Classification and special provision. Service so delivered shall be used only at the premises where the Service is connected.

1.03 Compliance with Service Classification: Service provided by the Company shall not be used for purposes other than those recognized within the applicable Service Classification or pursuant to any special provisions under which the Customer is being served. When the use of Service is not in compliance with the terms of any such special provisions or Service Classification, the Customer shall be transferred to and billed under the applicable schedule of charges or disconnected from Service as provided for in this Tariff. (Also see 4.07 and 7.03)

1.04 Residential Purposes: Electric loads required for the operation and use of an individual residence. Such loads may include that for lighting, cooking, appliance operation and water pumping as well as space and water heating. Also see Part I, Section F, Definition (14) for definitions of residence and residential structures.

1.05 Resale of Service: Customers shall not resell Service for profit. Customers who distribute electric energy from their Point of Delivery to other occupants of the premises may install metering at their own expense to determine the energy usage and amount owed to the Customer for energy usage at those sub-locations. Where the use of the premises is basically residential, such meters of sub-locations will be permitted only for those buildings constructed prior to January 1, 1978, which are co-operative or condominium residential apartment buildings, or are publicly financed or government-owned. A reasonable administrative charge may be made by the customer to the other occupants for determining and billing them for their energy usage.

For multiple occupancy residential buildings constructed after January 1, 1978, separate metering owned and installed by the Company is required for each dwelling unit as provided in the New Jersey Uniform Construction Code.

1.06 Unusual Conditions: The Company, at its sole discretion, may discontinue or refuse to provide Service to loads which might adversely affect the normal operation of facilities of the Company or its customers. Service to such loads may be provided where the customer, at its own expense, has installed corrective equipment in accordance with general or individual non-discriminatory requirements and specifications of the Company. The Company may also discontinue or refuse to supply service to loads so installed or connected that an unbalance greater than 10% exists between the phases of the customer's service. Customers should contact the Company prior to purchasing or connecting motors or other equipment to determine the maximum allowable inrush current and/or to determine the suitability of the equipment to the Company's system. (Also see Section 4.05)

Section 1 - Service Availability

1.07 Curtailable Load Limitation: The curtailable load of all customers provided for under this Tariff shall not exceed 2.5% of the Company's annual peak load in the preceding calendar year.

1.08 Multiple Services for Transmission Customers: Service will be supplied to several delivery points at the same or different voltages as mutually agreed, providing that such delivery points are connected together by interconnecting lines and transformation facilities which are either owned, operated, and maintained by the Customer, or owned, operated, and maintained wholly or in part by the Company, upon payment to the Company of a monthly charge of 1.5% of the original cost of such facilities as are provided by the Company. Such interconnection by mutual agreement may be operated either normally closed or open, and in either case shall be changed only by or at the direction of the Company for emergency and maintenance purposes. Where such interconnection is available, each separate delivery point will be individually metered, and billing shall be based on the sum of the highest coincident demands and the sum of the kilowatt-hours registered at the individual metering points after correcting for transformation losses. Such meter registrations are not measured at transmission voltage.

Section 2 - Service Applications, Agreements & Contracts

2.01 Application and Connection: All Applicants seeking to receive any type of Service from the Company under this Tariff shall contact the Company and specifically request the type and nature of Service. An Applicant for any Service under this Tariff may be required to sign an application or contract for Service. However, the Company may, in its sole discretion, accept an oral application from an Applicant. Applicants for Service shall supply to the Company all information deemed necessary by the Company from time to time to provide such Service including, but not limited to, connected electrical load, types of electrical equipment, and the mode of operation of the electrical equipment.

Upon the receipt of Service, the Applicant shall become a Customer of the Company. At any time, the Customer shall inform the Company in advance of any proposed additions to (or decreases in) the Customer's Connected Load.

Whenever Service is initiated to any Customer in any particular location or resumed after discontinuance at the request of the Customer, a Service Charge shall be made as specified in Part III of the Tariff.

If a Delivery Service Customer, for whatever reason, receives electric supply from the Company, that Customer will be considered a Full Service Customer beginning with the date on which such electric supply is furnished to the Customer by the Company.

2.02 Forms and Information: The Company will, upon request, explain the provisions of its Tariff and the conditions under which Service can be obtained. It is the responsibility of any Applicant for new or modified Service to obtain from the Company information regarding the characteristics of available Service, the Point of Delivery of Service, its designation of the point of Service Connection and meter location, and such other information as may be necessary to assure that the Customer's installation will be compatible with the facilities and Service the Company will provide before making the initial electrical installation or planning material changes in an existing installation. The Company will furnish such application and contract forms as may be appropriate. The Applicant shall supply all of the information called for by such forms.

2.03 Selection of Service Classification: The Company will assist in the selection of the Customer's applicable Service Classification. In furnishing such assistance, the Company assumes no responsibility whatsoever. If for any reason the Customer fails to make a selection, the Company will assign a Service Classification based upon facts at hand at the time Service is furnished. A Customer may, upon written notice to the Company, elect to change and to receive Service under any other applicable Service Classification or special provision. The Company will bill the Customer under the Service Classification so selected for Service delivered from the date of the next scheduled meter reading, but the Company may refuse to permit any further change in selection of Service Classification or special provision during the next twelve months, except as may be permissible under Section 1.03.

Section 2 - Service Applications, Agreements & Contracts

2.04 Modification or Rejection of Application: The Company may place limitations on the amount and character of Service it will provide, or may refuse to provide Service to new Customers or to any additional load of existing Customers, if it is not able to obtain, install, operate, or maintain the necessary equipment and facilities to provide such Service. The Company, after proper notice, may refuse to initiate Service or may discontinue Service to an Applicant, or to a Customer who is a member of the household or is a business associate, or landlord, of a former Customer then indebted to the Company for Services provided by the Company at any location, if the Company has reason to believe that substantially the same household or business will or does occupy the premises to be or being served and that the purpose of the present or earlier application is or was to circumvent payment of such indebtedness. However, if the household or business is not the same, the Company can only transfer the outstanding balance of amounts owed to the Company for Services provided by the Company to the former Customer of record for Service rendered at the prior location.

2.05 Contract by Use of Service: Receipt and use of Service provided by the Company shall render the recipient a Customer of the Company. If such Service is provided and accepted, or used in the absence of a written agreement for Service approved by the Company, such recipient shall be deemed to have entered into an agreement with the Company, the furnishing, receipt, and use of such Service shall be subject to the provisions of this Tariff and such Customer shall be charged for such Service in accordance with the applicable Service Classification.

2.06 Term of Contract: The term of contract is stated in the applicable Service Classification or in a written agreement. Customers shall give notice of intention to terminate Service to a responsible agent of the Company in accordance with the requirements of any applicable Service Classification or written agreement and, in any event, reasonably in advance of intended Service termination or change in Customer identity. Termination of Service on notice from the Customer, or for any other reason permitted by this Tariff prior to the completion of a contract for Service, shall not relieve the Customer from payment of the charges for the unexpired portion of the term and the same shall be due and payable immediately.

2.07 Unauthorized Use: Unauthorized connection to the Company's facilities, or the use of Service (either metered or unmetered) without Company authorization may be terminated by the Company without notice. The use of Service without notice to the Company shall render the End User or Beneficiary liable for any amount due for Service provided to the premises since the last reading of the meter as shown by the Company's records or for unmetered Service used since the last billing.

2.08 Statements by Agents: No representative of the Company has authority to modify any provision contained in this Tariff or bind the Company by any promise or representation contrary thereto, and the Company shall not be bound thereby.

2.09 Special Agreements: As a condition for establishing, continuing, or resuming the provision of Service in a situation where the Company incurs or will incur greater than normal investment cost or operating expense in order to meet the Customer's special or unusual Service requirements or to protect the Company's system from undue disturbance of voltage regulation or other adverse effects and in order to avoid undue discrimination, the Company may require an agreement for a longer term than specified in the applicable Service Classification, may require a contribution in aid of construction, and may establish such minimum charges and facilities charges as may be equitable under the circumstances. (Also see Section 4.05)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.01 Measurement of Electricity Consumption: The Service provided to the Customer will be measured separately for each Point of Delivery by metering. Bills will be based upon the registration of such metering equipment except as may be otherwise provided in this Tariff. Such registration shall be conclusive as measuring the quantity of Service received by the Customer except when the metering equipment fails to register or is determined to be registering outside the limits of accuracy prescribed by the BPU. In some instances the Company may, at its sole discretion, allow for unmetered Service. (Also see Sections 3.15 and 3.16)

3.02 Separate Billing for Each Installation: Service provided through each meter shall be billed separately in accordance with this Tariff. Conjunctive billing, which is the combination of the quantities of energy, demand, or other billing elements of two or more meters or Services into respective single quantities for the purpose of billing as if the bill were for a single meter or Service, will not be permitted except where more than one meter has been installed for Company operating reasons. (Also see Sections 1.02 and 3.15)

3.03 Meter Reading and Billing Period: Unless otherwise specified, the charges for Service are stated on a monthly basis. Meters are read on a regular schedule, as nearly as practicable every 30 days. The term "month" as used in this Tariff, generally means the period between any two consecutive regularly scheduled meter readings. The term "billing period" usually refers to the interval of time elapsing between two consecutive meter readings, but it may mean other time intervals, either actual or estimated, taken or made for the purpose of computing the amount due to the Company from the Customer. Bills to Customers will normally be rendered monthly, but the Company may, in its sole discretion, read meters and render bills generally, or to limited groups of Customers, on other than a monthly basis for either experimental purposes or as a regular procedure, after giving reasonable notice to the affected Customers and to the BPU. In such event the monthly charges stated in the applicable service classification shall be prorated to conform to the new billing period. (See NJAC 14:3-7.4)

3.04 Prorating of Monthly Charges: All bills for periods other than 26 to 35 days inclusive will be computed by prorating the monthly charges provided in the applicable service classifications on the basis of the relationship between the number of days in the billing period and 30 days.

3.05 Estimated Bills: Where the Company has not obtained a reading of the meter it may submit a bill for the minimum charge, or estimate the amount of Service provided and submit an estimated bill. Such bill is subject to adjustment on the basis of the actual Service provided as established by the next actual meter reading, or for any unusual circumstances known to have affected the amount of Service provided.

The Company reserves the right to discontinue Service when a meter reading has not been obtained for eight months or more and after written notice is sent to the customer per NJAC 14:3-7.2. The Company will use all reasonable means to obtain a meter reading before discontinuing Service. (Also see Section 7.03 and NJAC 14:3-3A.1)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.06 Billing Adjustments: An adjustment of charges due to the Company for Services provided by the Company will be made when a meter fails to register within the limits of accuracy prescribed by the BPU in accordance with NJAC 14:3-4.6, or for any other legitimate reason, in which case such adjustment shall not be for a period of more than six years prior to the time the reason for the adjustment became known to the Company. (See NJAC 14:3-4.6)

3.07 Billing of Charges in Tariff: Unless otherwise designated, the charges set forth in this Tariff shall apply to Service rendered on and after the effective date specified in the applicable Service Classification.

3.08 Payment of Bills: Bills for Service provided by the Company are payable when rendered and are due within fifteen days of the mailing date of the bill or as otherwise prescribed by regulation NJAC 14:3-3A.3. They can be paid at any business office of the Company, to any duly authorized collector or collection agency, by mail, or by electronic funds transfer. If a bill is not paid by the date indicated on the bill, the Company, on not less than ten days written notice, may discontinue service to the Customer after 27 days following rendition of the bill or as otherwise prescribed by regulation. (See NJAC 14:3-3A.3)

Whenever a residential Customer advises the Company that the Customer wishes to discuss a deferred payment agreement because of a present inability to pay a total outstanding bill and/or a security deposit, the Company will make a good faith effort to provide the Customer with a reasonable deferred payment agreement. Either prior to or after the discontinuance of service for non-payment, a residential Customer may be required to pay a down payment of not more than 25% of the total outstanding bill due at the time of the agreement. Deferred payment agreements which extend more than two months must be in writing. The Company is not required to offer or enter into more than one deferred payment agreement in a 12-month period, but the Company may, in its sole discretion, elect to offer more than one such agreement in the same 12-month period. If the Customer defaults on any of the terms of the agreements, the Company may discontinue service after providing the Customer with a notice of discontinuance. (See NJAC 14:3-7.7)

A Customer's failure to receive a bill shall not relieve the Customer of any of the Customer's obligations hereunder.

Where a non-residential Customer requests a deferred payment agreement, the agreement shall be limited to a period of no more than three months, and the Customer may be required to make a partial payment at the time of entering into the deferred payment agreement. The amount of the partial payment shall be no more than one half of the amount past due and owing at that time. The existence of a deferred payment agreement does not relieve the Customer of applicable monthly late payment charges. (See Section 3.19)

3.09 Guarantee of Payment: Where the credit of an Applicant for Service is impaired or not established, or where the credit of a Customer has become impaired, a money deposit or other guarantee satisfactory to the Company may be required as security for the payment of bills for Service before the Company will commence or continue Service. If a residential Customer's Service has been terminated for non-payment of bills, the Company may not condition restoration of Service on payment of a deposit unless said deposit had been included as a charge on prior bills, or prior notice to the Customer had been given. (See NJAC 14:3-3.4)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.10 Amount of Credit Deposit: The deposit from the Customer shall be not less than twice the estimated or actual bill for a single billing period at the applicable rate. In the case of a Customer taking Service for less than 30 days, a credit deposit may be required in an amount equal to the estimated bill for such temporary period. The Company will issue a receipt to each Customer making a deposit. (See NJAC 14:3-3.4)

3.11 Interest on Credit Deposit: All money deposits under Section 3.09 shall bear simple interest payable at the rate and in the manner specified under NJAC 14:3-3.5(d). Deposits shall cease to bear interest upon termination of Service.

3.12 Return of Credit Deposit: Upon termination of Service and payment in full of all unpaid bills for Service, the Company will return the deposit plus accrued interest, or will deduct from the deposit and interest all amounts due and return the difference, if any, to the depositor. The Company shall have a reasonable time in which to read meters and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposit. The credit deposit is not a floating credit available to be used by the Customer for the payment of interim bills for service, but the Company may apply the deposit and any accrued interest against any unpaid bills and require the Customer, as a condition on continuing Service, to restore the deposit to an amount, determined in accordance with the principles set forth in Sections 3.09 and 3.10, sufficient to secure the payment of future bills. Residential customer accounts will be reviewed at least once every year and non-residential Customer accounts at least once every two years. Should such review indicate that the Customer has established satisfactory credit with the Company, the credit deposit plus accrued interest, if any, will be returned to the depositor. Such return of a credit deposit shall not serve to waive the Company's right to re-establish the credit deposit as required herein above. The Company may require surrender of the receipt issued when the deposit was made, or in lieu thereof, proof of identity before returning the deposit or any part thereof. (See NJAC 14:3-3.5)

3.13 Final Bill: A customer intending to discontinue Service shall give the Company reasonable notice thereof and arrange for the reading of the meter. Where the Customer is discontinuing all Service, the reading shall be regarded as a final reading and the Company will read the meter within forty-eight hours of receipt of such notice unless a holiday or a weekend intervenes or the Customer desires otherwise. If, because of conditions occasioned by the Customer, or by reason of compliance with the Customer's request, the final reading of the meter must be obtained outside of regular business hours, the Customer will be subject to the service charges specified in the applicable Service Classification within this Tariff.

Whether or not the Customer gives notice of discontinuance, the Customer shall be liable for Service delivered to the premises until the final reading of the meter can be obtained by the Company. Where the Customer is discontinuing all Service, the bill for Service rendered until the final meter reading, plus all other charges due and any applicable minimum charge for the unexpired term of a contract, is due and payable immediately upon presentation. Where the Service in question is unmetered, a final bill shall be rendered upon discontinuance of Service.

Section 3 - Billings, Payments, Credit Deposits & Metering

3.14 Taxes on Contributions in Aid of Construction and Customer Advances or Deposits: Any contribution in aid of construction ("CIAC"), customer advance or deposit, or other like amount received from Customers which shall constitute taxable income as defined by the Internal Revenue Service may be increased to include a payment equal to the applicable current taxes incurred by the Company as a result of receiving such monies, less the net present value of future tax benefits related to the tax depreciation guideline-life applicable to the property constructed with such monies, which for transmission or distribution items shall be taken to be 20 years. The discount rate to be used for such present value calculation will be the Company's last allowed overall rate of return.

3.15 Unmetered Service: Where the Customer's equipment is of such a character and its operation is so conducted that the Customer's use of service at the Point of Delivery is substantially invariable over the period Service is supplied, thus permitting accurate determination of billing quantities by calculation based on the electrical characteristics of such equipment, the Company may omit the installation of metering equipment and, with the consent of the Customer, use the respective quantities, so determined, for billing purposes under the applicable Service Classification. The Customer shall not make any change whatever in the equipment or mode of operation thereof, Service to which is billed in the foregoing manner, without first obtaining the Company's consent in writing. If the Customer changes equipment or mode of operation, any Service to such changed equipment or operation shall be deemed unauthorized use and shall be subject to discontinuance as provided elsewhere in this Tariff.

3.16 Non-measurable Loads: Customers with equipment which creates unusual fluctuations, which cannot be measured by standard metering facilities, shall have the maximum 15-minute demand, monthly KWH, and reactive component calculated for such equipment, and added to any such measured quantities for the customer's remaining load for billing purposes under the applicable Service Classification.

3.17 Equal Payment Plan for Individual Residential Dwelling Units: The Company may, upon request by a residential Full Service Customer, determine a payment plan of twelve equal monthly payments for the Customer. Monthly payments required under this plan may be revised by the Company one time during the payment plan period as rate changes or special conditions warrant. If actual charges are more or less than the estimated amounts, billing adjustments necessary to provide for the payment of the actual charges due for Service rendered under this plan shall be made in the twelfth month of the plan, or in the event the Equal Payment Plan is terminated, on the next bill. The Company may terminate this plan at any time as to any Customer if any monthly bill rendered to such Customer under this plan is unpaid when the next monthly bill is rendered. (See NJAC 14:3-7.5)

3.18 Returned Payment Charge: A charge of $15 will be assessed against a Customer's account when a check or an electronic payment or other form of funds transfer, which has been issued to the Company, is returned by the bank as uncollectible, or otherwise dishonored by the bank from which the funds were drawn.

Section 3 - Billings, Payments, Credit Deposits & Metering

3.19 Monthly Late Payment Charge: Upon the non-receipt of payment for services provided by the Company or an Alternative Electric Supplier by a Customer receiving Service under Service Classifications GS, GST, GP, GT, SVL, MVL, ISL, LED and Rider CEP and receiving a bill for such service rendered by the Company, as opposed to a consolidated bill rendered by an Alternative Electric Supplier, except for State, County, and Municipal Government accounts, a Late Payment Charge at the rate of 1.5% per monthly billing period shall be applied. This charge will be applied to all amounts previously billed, including any unpaid late payment charge amounts applied to previous bills, which are not received by the Company when the next regular bill is calculated. The amount of the Late Payment Charge to be added to the unpaid balance shall be determined by multiplying the unpaid balance by the monthly Late Payment Charge rate of 1.5%. (See NJAC 14:3-7.1)

3.20 Delinquent Charge: For Customers receiving Service under Service Classifications RS, RT, RGT, GS and GST, a field collection charge will be applied for each collection visit made by the Company to the Customer's premises, except Customers who qualify for protection under the standards set forth in the NJAC 14:3-3A.5 as detailed in the Stipulation of Final Settlement (Docket No. ER95120633).

3.21 Summary Billing: Upon a Customer's request and the Company's approval, a Customer with multiple Full Service accounts may receive Summary Billing, in which the billing information for the multiple accounts is reported on a single statement, for the convenience of the Customer. Summary Billing shall not be permitted for any delinquent accounts, and shall be permitted only in those cases where meter reading dates and due dates of the multiple accounts allow for Summary Billing without adversely affecting the timely payment of bills and where summary billing does not have an adverse financial impact on the Company. The Company may, in its sole discretion, discontinue Summary Billing, or charge Customers an additional amount for Summary Billing to offset any actual or potential adverse financial impact on the Company. A single due date for accounts that are billed in summary shall be established by the Company and provided to the Customer. Summary Billing shall not commence unless and until the Customer agrees to the due date established for such Summary Billing.

3.22 Special Billing: The Company shall consider all requests from Customers to deviate from the Company's standard billing practices and procedures, including those described in this Tariff. The Company may, in its sole discretion, agree to provide special billing to a Customer, subject to, a payment by the Customer of all costs associated with the Company providing such special billing.

3.23 Metering: The Company shall maintain, install and operate meters and related equipment as necessary to measure and record the Customer's consumption and usage of all services provided under this Tariff. The Company may, in its sole discretion, install such meters and related equipment (including, but not limited to, telemetering equipment) it deems reasonable and appropriate to provide service to Customers under this Tariff. The Company may, in its sole and exclusive discretion, install such special metering as may be requested by a Customer, subject to the Customer paying all of the Company's material, labor, overheads and administrative and general expenses relating to such facilities.

The Company shall conduct inspections and tests of its meters in accordance with prudent electric practices and as otherwise prescribed by the BPU.

Section 3 - Billings, Payments, Credit Deposits & Metering

3.23 Metering: (Continued)

If requested by the Customer, the Company may, in its sole discretion, elect to provide kilowatt-hour pulses and/or time pulses from the Company's metering equipment. All costs for providing the meter pulses shall be paid by the Customer. If a Customer's consumption of kilowatts and/or kilowatt-hours increases as a result of interruptions or deficiencies in the supply of pulses for any reason, the Company shall not be responsible or liable, for damages or otherwise, for resulting increases in the Customer's bill.

If requested by a Customer, the Company may, in its sole discretion, elect to provide metering to a service location other than what is presently installed or otherwise proposed to be installed by the Company at that location. All costs for special metering facilities provided by the Company, including, but not limited to, all material, labor, overheads and administrative and general expenses, shall be billed to and paid by the Customer.

Section 4 - Supply and Use of Service

4.01 Continuity of Service: The Company will use reasonable diligence to maintain a regular and uninterrupted provision of Service, but should the Service be interrupted, curtailed, suspended, or discontinued by the Company for any of the reasons set forth in Section 7 of these Standard Terms and Conditions, or should the Service be interrupted, curtailed, deficient, defective, or fail by reason of any natural disaster, accident, act of a third party, strike, legal process, governmental interference or by reason of compliance in good faith with any governmental order or directive, notwithstanding that such order or directive subsequently may be held to be invalid, or other causes whatsoever beyond its control, the Company shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure. The Company will not be responsible for any damage or injury arising from the presence or the use of Service provided to the Customer by the Company after it passes from the Company's facilities to the Point of Delivery, unless such damage or injury is caused by the sole negligence or willful misconduct of the Company. Any damage or injury arising from occurrences or circumstances beyond the Company's reasonable control, or from its conformance with standard electric industry system design or operation practices, shall be conclusively deemed not to result from the negligence of the Company. Due to the sensitive nature of computers and other electric and electronically controlled equipment, Customers, especially three-phase Customers, are advised to and should provide protection against such variations in power and voltage supply.

4.02 Temporary Service: Service for a temporary or short term period will be provided and billed under the applicable Service Classification when the Company's available installed facilities are of adequate capacity to render such Service, provided the Customer pays in advance the estimated net cost of installing and removing all facilities provided to furnish such Service. If the total period of temporary Service is less than one month, the total billing for such period shall not be less than the stated monthly minimum of the applicable Service Classification. At the option of the Company, bills for temporary Service may be prorated and rendered at periodic intervals of less than one month and are due and payable upon presentation. The Company's specifications for the Customer's installation are available from the Company upon request.

4.03 Transformation Facilities for Transmission Customers: Where, for the mutual convenience of the Company and Customer, the transformation equipment at a delivery point is utilized by both parties, the Company will provide such facility at a monthly charge of 1.5% of the prorated cost. The prorated cost shall be (1) the product of (a) the highest 15-minute demand (rounded to the next highest 100 KW) established by the Customer on such commonly-used transformation facility since Service was originally established, and (b) the Company's book cost of such commonly-used transformer substation less those items of equipment devoted solely to uses other than supplying the Customer, (2) divided by the maximum capability of the transformation equipment when operating under load conditions. In the event that the transformer bank's maximum capability is altered, either by changes in the transformers, the transformer cooling equipment, or in the characteristics of the Customer's load, item (2) above shall be redetermined to reflect the changed conditions.

Section 4 - Supply and Use of Service

4.04 Emergency Curtailment of Service: The Company may curtail or discontinue the provision of Service to any Customer, upon reasonable notice if possible, in the event it becomes necessary to do so in case of emergencies or in compliance with an order or directive of Federal, State, or municipal authorities. The Company may interrupt Service to any Customer or Customers in an emergency threatening the integrity of its system or to aid in the restoration of Service if, in its sole judgment, such action will alleviate the emergency condition and enable it to continue or restore Service consistent with the public welfare. (Also see Sections 4.01 and 7.02) In the event of an actual or threatened restriction of fuel supplies available to its system or the systems to which it is directly or indirectly connected, the Company may curtail or interrupt Service or reduce voltage to any Customer or Customers if, in its sole judgment, such action will prevent or alleviate the emergency condition. (See NJAC 14:3-3A.1)

4.05 Special Company Facilities: At the Customer's request, or as required, subject to approval by the Company, the Company will furnish and install on its system, special, substitute, or additional facilities to meet the Customer's special or additional requirements or to protect the Company's system from disturbance of standard voltage regulation that otherwise would be caused by the operation of customer's equipment. When the Company furnishes facilities not normally supplied or when the estimated or actual cost of such special substitute or additional facilities exceeds the estimated cost of the standard facilities that normally would be supplied by the Company without special charge, either (a) the Customer shall pay in a manner to be agreed upon a facilities charge annually amounting to 18% of such additional cost, or (b) by mutual agreement the Customer may pay an amount equivalent to such additional cost, plus applicable taxes. However, alternative (a) shall not be available unless the facilities are such as are commonly and usually transferred from place to place for use in the Company's system or are reasonably capable of reuse. The Customer may also be subject to other monthly or special charges in order to meet their special needs.

4.06 Single Source of Energy Supply: No Customer may maintain or operate any source of electric energy on his premises or at his contract location in a manner whereby such source may become interconnected with the Company's facilities without the prior written approval of the Company. Such prior approval may be conditioned, among other things, on the installation and operation by the Customer at the Customer's cost and expense of such switches and/or protective devices as the Company may deem necessary to prevent injury to persons or damage to property of either the customer or the Company. Such approved interconnection may be maintained only at the appropriate rates and charges as provided in this Tariff.

4.07 Changes in Customer's Installation: The Customer, prior to making any material increase or decrease in Connected Load, demand, or other conditions of use of Service or change of purpose, arrangement, or characteristics of electrical equipment, shall notify the Company of such intention so that the Company may determine if any changes in its distribution facilities or in the Point of Delivery will be required in order that safe, adequate, and proper Service may be supplied to the Customer under the proposed changed conditions. Prior to starting any work, the Customer or his agent shall submit for the Company's approval sufficient copies as required of the plans of such proposed installations, together with a list of the principal apparatus to be used. The Company will advise the Customer if any feature of the proposed changed conditions would be incompatible with such Service. (Also see Section 5.06) Such proposed changes in the Customer's Service conditions shall not be made effective until they have been approved by the Company.

Section 4 - Supply and Use of Service

4.08 Customer's Liability to Company: Failure of the Customer to give prior notice of changes in conditions as described in Section 4.07 shall render the Customer responsible and liable for any personal injury and any property damage caused by the changed conditions, including damage to the Company's property and injury to its employees. In those cases where the Customer's bill is based on the connected load, failure to give notice of changes therein will not relieve the Customer from liability for payment of proper charges for Service based upon such changed conditions from the date such change first occurred, nor entitle the Customer to a refund or adjustment if the charges billed exceed the amount that would normally be applicable under the changed conditions.

4.09 Request for Relocation of, or Work on, Company Facilities: When the Company is requested to relocate or work on its facilities and such relocation or work is for the purpose of enabling the Customer to work on or maintain his electrical facilities or building, or perform work or construction safely in the vicinity of Company equipment, the Customer shall pay to the Company, in advance of any relocation or work by the Company, the estimated cost to be incurred by the Company in performing such relocation or work. For work of a routine nature frequently performed within the Company's service area, the Company may specify a flat fee based upon the average costs of performing such work. (Also see Sections 6.04, 6.06, and 6.08)

4.10 Liability for Supply or Use of Electric Service: The Company will not be responsible for the use, care, condition, quality or handling of the Service delivered to the Customer after same passes beyond the point at which the Company's service facilities connect to the Customer's wires and facilities. The Customer shall hold the Company harmless from any claims, suits or liability arising, accruing, or resulting from the supply to, or use of Service by, the Customer.

4.11 Relocation of Meters or Service Equipment: Where meter locations are changed from indoor to outdoor, the Company may permit feeding back from the new meter location to the original Service Entrance. When an existing Service Entrance is to be changed, the old Service shall remain active and properly metered until the old Service is disconnected and the new Service is reconnected. When it is impractical to comply with this requirement, the Company must be contacted and arrangements made to accomplish the changeover. Metered and unmetered conductors will not be permitted in the same conduit or raceway, except in special cases where Company approval has been obtained.

4.12 Liability for Acts of Alternative Electric Suppliers: The Company shall have no liability or responsibility whatsoever to the Customer for any agreement, act or omission of, or in any way related to, the Customer's Alternative Electric Supplier.

Section 5 - Customer's Installation

5.01 General Requirements: The Customer's installation must conform to the Company's specifications and all requirements of municipal and State authorities and regulations set forth in the National Electric Code in effect at the time of such installation. The Company will, however, install and maintain facilities on the Customer's premises at the Customer's cost when the Company determines such installation and maintenance to be necessary or more convenient for the delivery of Service and there is mutual agreement as to the installation and maintenance cost. Where for engineering or operating reasons it is necessary or desirable to install a substation, transformers, capacitors, control, protective or other equipment on the Customer's premises in order to supply the Service required by the Customer, the Customer shall provide a suitable place and housing for such facilities. The Company's specifications for the Customer's installation are available from the Company upon request.

5.02 Service Entrance: The Customer's Service Entrance facilities shall extend from the Point of Delivery specified by the Company to an approved entrance switch cabinet located on the Customer's premises. With the exception of metering equipment and related facilities furnished by the Company, all of the facilities necessary to conduct electricity from the Point of Delivery to the Customer's circuits shall be installed, owned, and maintained by the Customer. The Customer must provide and install an approved service head and assure all fittings used in the Service Entrance provide a water-tight connection. At least three feet of wire must be left for the connection to the Service Drop on all services. (Specifications for service installations will be furnished by the Company upon request.)

5.03 Inspection and Acceptance: The Company may refuse to connect with any Customer's installation or to make additions or alterations to the Company's Service Connection when such installation is not in accordance with the National Electrical Code, or with the Company's requirements, or where a certificate approving such installations has not been issued by an electrical inspection authority certified by the New Jersey Department of Community Affairs for the area in which the installation is located, or by a City or County Inspection Authority having exclusive authority to make electrical inspection in such area. (See NJAC 14:3-8.3(g) and (h))

5.04 Special Customer Facilities: The Customer shall furnish at his own expense any special facilities necessary to meet his particular requirements for Service at other than the standard conditions specified under the provisions of the applicable Service Classification. (Also see Section 5.05)

5.05 Regulation of Power Factor: The Company shall have the right to require the Customer to maintain a power factor in the range of 87% to 100% coincident with the Customer's maximum on-peak monthly demand and to provide, at its sole expense, any corrective equipment necessary in order to do so. The Company may inspect the Customer's installed equipment and/or place instruments on the premises of the Customer in order to determine compliance with this requirement, as deemed appropriate by the Company. The installation by the Company of corrective devices necessary for compliance with this provision, shall, as deemed appropriate by the Company, be billed to the Customer under the provisions of Section 4.05. The Company is under no obligation to serve, or to continue to serve, a Customer who does not maintain a power factor acceptable to the Company. (Also see Sections 5.01 and 5.04)

Section 5 - Customer's Installation

5.06 Change in Point of Delivery: In the event that the Company shall be required by any governmental authority to relocate its distribution facilities or to place any portion of them underground, the Customer shall at its own expense make such changes in its Service Entrance and/or in its underground Service Connection as may be necessary in order to conform to the new Point of Delivery specified by the Company. Any change requested by the Customer in the location of the existing Point of Delivery, if approved by the Company, will be at the expense of the Customer.

5.07 Liability for Customer's Installation: The Company will not be liable for damages to or injuries sustained by the Customer or others, or by the equipment or property of Customer or others, by reason of the condition, character, or operation of the Customer's wiring or equipment, or the wiring or equipment of others.

5.08 Meter Sockets and Current Transformer Cabinets: Upon the Company's designation of a Point of Delivery at which its Service line will terminate, the Customer shall provide, at its sole cost and expense, a place suitable to the Company for the installation of metering and all other electric facilities needed for the provision of electric energy by the Company or an Alternative Electric Supplier. It shall be the Customer's responsibility to furnish, install, and maintain self-contained meter sockets and current transformer cabinets in accordance with Company specifications which are available upon request.

5.09 Restricted Off-Peak Water Heater Specifications: Service supplied under Service Classification RS - Residential Service, Special Provision (a), or Service Classification GS - General Service Secondary, Special Provision (d), must conform to the following requirements as well as any other applicable conditions of Service:

(a) The minimum capacity of the water heater should not be less than 50 gallons.
(b) Should the water heater have two non-inductive heating elements, each shall be controlled by its own thermostat and both shall be electrically interlocked to prevent simultaneous operation, with the upper heating element located to heat the top one-quarter of the tank volume and the lower element located to heat the entire tank.
(c) The upper heating element may be wired to operate during the on-peak as well as off-peak periods, whereas the lower element, or single element (in a one-element water heater), may operate only during the off-peak periods.
(d) The wattage of each heating element shall not be in excess of 30 watts per gallon of tank volume, rounded to the nearest 500 watts.
(e) Service to water heaters will be supplied at single-phase 208 or 240 volts, depending on the voltage available. For the supply of equipment with one tank or a combination of tanks in excess of 250 gallons or in excess of 7500 watts, the Company must be consulted for installation specifications.

Section 5 - Customer's Installation

5.10 Restricted Controlled Water Heating Specifications: Service supplied under Service Classification RS - Residential Service, Special Provision (b), or under Service Classification GS - General Service Secondary, Special Provision (e), must conform to the following requirements as well as any other applicable conditions of Service:

(a) The water heater shall have two non-inductive heating elements, each controlled by its own thermostat and electrically interlocked to prevent simultaneous operation.
(b) The upper heating element shall be located to heat the top one-quarter of the tank volume and the lower element located to heat the entire tank.
(c) The wattage of each element shall not be in excess of 35 watts per gallon of tank volume rounded to the nearest 500 watts for water heater of 40 gallons or more.
(d) Thirty-gallon water heaters may contain either one or two heating elements, with an element size not to exceed 1500 watts.

Section 6 - Company's Equipment on Customer's Premises

6.01 Ownership, Maintenance and Removal: The Company shall furnish, install and maintain the meters, related equipment and facilities necessary for Service unless otherwise stated. All facilities and equipment supplied by the Company shall remain exclusively its property. The Company may remove such facilities and equipment from the premises of the Customer after termination of Service.

6.02 Customer's Responsibility: Under certain circumstances, it may be necessary for the Company to install equipment on the Customer's premises. This equipment may be placed in vaults, manholes, hand-holes, outdoor substations on concrete pads, etc. These Customer-owned facilities must be constructed in accordance with all applicable codes and to the Company's specifications. Prior to starting work, the Customer or his agent shall submit for the Company's approval plans of such proposed installations, together with a list of the principal apparatus to be used. The Customer shall be responsible for the protection and safe-keeping of the facilities and equipment of the Company while on the Customer's premises and shall not permit access thereto except by duly authorized governmental officials and representatives of the Company. The Customer should notify the Company immediately if any question arises as to the authority or credentials of any person claiming to be a governmental official or a Company representative. Any malfunction or defect in the Company's equipment observed by the Customer should be reported to the Company immediately. (See Section 6.04)

6.03 Access to Customer's Premises: The Company shall have the right to construct, operate, modify, replace and/or maintain any and all facilities it deems necessary to render Service to the Customer and adjoining customers upon, over, across and/or under lands owned or controlled by the Customer. The Company shall have the right of reasonable access to all property furnished by the Company, at all reasonable times for the purpose of inspection of any premises incident to the rendering of service, reading meters, or inspecting, testing, or repairing its facilities used in connection with providing the Service, or for the removal of its property. The Company shall have the right to enter upon the lands owned or occupied by the Customer for the purpose of moving, removing, replacing, altering, accessing, servicing or maintaining any structures, fixtures, equipment, instruments, meters or other property owned by the Company, above or beneath such lands, and shall have the right to trim, cut, move, clear or destroy any trees, shrubs, plants or other growth on such lands as necessary to keep or prevent same from endangering or interfering with the Company's structures, fixtures, equipment, instruments, meters or other property, or with the providing of safe, adequate and reliable Service. The Customer shall obtain, or cause to be obtained, all permits needed by the Company for access to the Company's facilities. Access to the Company's facilities shall not be given except to authorized employees of the Company or duly authorized governmental officials. During an alleged diversion of Service, it is the Company's responsibility to obtain access to the Company's equipment in accordance with NJAC 14:3-3.6 and 6.8. (See Section 7.03)

Section 6 - Company's Equipment on Customer's Premises

6.04 Tampering: In the event it is established that the Company's wires, meters, meter seals, switch boxes, or other equipment (including, but not limited to, revenue protection locks, meters and other devices) on the Customer's premises have been tampered with, the Customer shall be required to bear all of the costs incurred by the Company including, but not limited to, the following: (a) investigations, (b) inspections, (c) costs of prosecution including legal fees, and (d) installation of any protective equipment deemed necessary by the Company. Furthermore, where tampering with the Company's or Customer's facilities results in incorrect measurement of the Service, the Customer shall pay for such Service as the Company may estimate from available information to have been used on the premises but not registered by the Company's meter or meters. Tampering with the Company's facilities is punishable by fine and/or imprisonment under New Jersey law. (See NJAC 14:3-7.8)

6.05 Payment for Repairs or Loss: The Customer shall pay the Company for any damage to or any loss of Company's property located on the Customer's premises caused by the act or negligence of the Customer or his agents, servants, licensees or invitees or due to the Customer's failure to comply with the applicable provisions of this Tariff.

6.06 Service Disconnection and Meter Removal Authorized: A licensed electrician or an electrical contractor, upon notifying the Company, will be authorized to disconnect and permanently reconnect a single-phase secondary overhead service that is 200 amps or less. Disconnections or meter removals performed by persons other than authorized licensed electricians, authorized electrical contractors, or authorized Company personnel are prohibited and shall constitute tampering. (See Sections 6.07 and 6.08)

6.07 Reconnection of Service or Replacement of Meter: The Company shall have sole authority to reconnect a service or replace a meter. However, upon contacting the Company, a licensed electrician or electrical contractor may be authorized to reconnect a service or reinstall the meter upon completion of his work as provided in Section 6.06. (See Section 4.09)

6.08 Sealing of Meters and Devices: It is the practice of the Company to seal all meters. Service Entrance switches, wiring troughs, or cabinets connected ahead of meters or instrument transformers, will be sealed by the Company. When Service is introduced prior to the completion of the wiring, or where Service is discontinued, the Company or its designated agent may seal all Service equipment. No one except an authorized employee of the Company is permitted to remove a Company seal or padlock, except as provided in Section 6.06.

6.09 Power Disturbance Protection Service: The Company shall offer to provide the following to Customers which request power disturbance protection: (a) diagnostic services to identify the probable cause of electrical disturbance, (b) engineering analysis and design to develop a power conditioning solution, (c) electrical system modification and/or power conditioning equipment installation, and (d) maintenance of the power conditioning systems. Charges for such Service shall be not less than the actual cost to provide such Service. The Company shall not be liable for damage or injury arising from the improper use of power disturbance protection/conditioned power service, systems or equipment, or for any costs or damages attributable to injury or the loss of the Customer's business, production or facilities resulting from the failure of power disturbance protection/conditioned power service, systems or equipment.

Section 7 - Suspension or Discontinuance of Service

7.01 Work on Company's Facilities: The Company may, upon reasonable notice when it can be reasonably given, suspend, curtail, or interrupt Service to a Customer for the purpose of making repairs, changes, or improvements to or in any of its facilities either on or off the Customer's premises.

7.02 Compliance with Governmental Orders: The Company may curtail, discontinue, or take appropriate action with respect to Service, either generally or as to a particular Customer, as may be required by compliance in good faith with any governmental order or directive, and shall not be subject to any liability, penalty, or payment, or be liable for direct or consequential damages by reason thereof, notwithstanding that such instruction, order or directive subsequently may be held to be invalid or in error. Verbal or written orders of police, fire, public health, or similar officers, acting in the performance of their duties, shall be deemed to come within the scope of this subsection. (See Sections 4.01 and 4.04)

7.03 Customer Acts or Omissions: The Company may, upon giving reasonable notice to the Customer when it can be reasonably given, suspend or discontinue Service and remove the Company's equipment from the Customer's premises for any of the following acts or omissions:

(a) Non-payment of any valid bill due from the Customer or the Customer's resident spouse for Service furnished by the Company at any present or previous location. However, non-payment for business Service shall not be a reason for discontinuance of residential Service, except in cases of diversion of Service. (See Section 3.08)
(b) Tampering with any of the Company's facilities. (See Section 6.04)
(c) Fraudulent representation or application in relation to the use of Service. (See Section 1.03)
(d) Moving from the premises, unless the Customer has requested the Company to continue Service at the Customer's expense. (See Section 2.06)
(e) Resale, transfer, or delivering any part of the Service supplied by the Company to others without the Company's permission. (See Section 1.05)
(f) Refusal or failure to make or increase an advance payment or credit deposit as provided for in this Tariff. (See Section 3.09)
(g) Refusal or failure to contract for Service when reasonably required by the Company to do so. (See Section 2)
(h) Connecting and operating equipment so as to produce disturbing effects on the Company's system or Service to other Customers. (See Section 1.06)
(i) Refusal or failure to comply with any provisions of this Tariff.
(j) Where, in the Company's opinion, the condition of the Customer's installation presents a hazard to life or property.
(k) Refusal or failure to correct any faulty or hazardous condition of the Customer's installation.
(l) Refusal of reasonable access to Customer's premises for necessary purposes in connection with rendering of Service, including meter installation, reading or testing, or the maintenance or removal of the Company's property.

Failure by the Company to exercise its rights shall not be deemed a waiver thereof. (See NJAC 14:3-3A.1)

Section 7 - Suspension or Discontinuance of Service

7.04 Reconnection of Service: When Service has been discontinued by reason of any act or omission or default of the Customer, the Company will not restore service to the Customer's premises until the Customer has made proper application therefor and has rectified the condition or conditions that caused the discontinuance. It is further required that the Customer shall have paid all amounts due as provided in this Tariff including the Service Charge of the applicable Service Classification to reimburse the Company in part for the cost of special handling of the account and of the special costs associated with the disconnection and reconnection of Service.

Section 8 - Service Connections

8.01 General: This Section governs situations in which the Company's distribution lines and facilities are of adequate capacity to serve the Customer's load and are located adjacent to the Customer's premises. In these situations, the connection between the Company's system and the Customer's installation shall be made by the Company and established in accordance with the provisions of this Section.

8.02 Overhead Service Connection: The Company will install, connect, and maintain at its own cost and expense not more than one Service Drop for each contract location. The Company shall not be required to install a Service Drop where its length would exceed the safe distance over which a single span of Service Drop conductors can be placed.

8.03 Underground Secondary Service Connection (other than a manhole duct system) to Serve an Individual Residential Customer/Applicant: (a) A residential Customer or Applicant electing an underground Service Connection instead of an overhead Service Connection can elect to install such connection at his/her own cost and expense in accordance with the Company's specifications for such construction. At the Customer's option, the Company will install and connect such underground Service Connection, upon the Customer making a non-refundable contribution, as described in (b) below. In either case, the Company will assume ownership and responsibility for maintenance, including replacement when appropriate, at the Company's expense, of the underground Service Connection upon connection to the Company's system (subject to receipt of requisite easements, rights of way or the like, at no cost to the Company). In addition, at the Customer's option, the Company will assume ownership and responsibility for maintenance, including replacement when appropriate, at the Company's expense, of all private residential underground Service Connections installed prior to the date of this tariff sheet (subject to receipt of requisite easements, rights of way or the like, at no cost to the Company). In connection with any Company work performed under this Section 8.03, whether on Company-owned or Customer-owned facilities, the Company must first be granted the right by the Customer to trim or remove vegetation and to remove structures or other obstructions that interfere with such work and the Company will not be responsible for the costs of repair, replacement or restoration thereof.

(b) The non-refundable contribution will be equal to the predetermined unit cost differential of furnishing such facilities underground instead of overhead. If the Customer provides the trench, the underground Service Connection charge will be credited accordingly.

Section 8 - Service Connections

8.04 Underground Distribution Service Connection to Serve a Non-Residential Customer: Where a non-residential Customer or Applicant elects such underground Service Connection instead of an overhead Service Connection, or where an overhead or secondary network system is not available, the Customer or Applicant, or the Company at the Customer or Applicant's discretion, must install such connection at the Customer or Applicant's own cost and expense in accordance with the Company's specifications for such construction. The Service Connection will be made by the Company, and shall be owned and maintained, and when necessary, relocated in accordance with the Company's specifications, by Customer at the Customer's own cost and expense.

8.05 Underground Distribution Service Connection (other than a manhole duct system) in Residential Subdivision: Where distribution circuits have been extended underground pursuant to Tariff Part II, Section 10, the Service Connection shall be installed underground as part of the entire electrical system for the development upon payment of the applicable charges computed in accordance with Appendix A of these Standard Terms and Conditions.

8.06 Conventional Underground Service Connection (Secondary Network System): If a Customer's or Applicant's facility is located in a designated network system, one conventional underground Service Connection to each contract location will be provided by the Company without cost to the Customer which shall terminate at a point not more than 30 feet distant from the curb, measured at right angles to the curb, nearest the point of connection to the Customer's facilities, provided, however, that the Company will not supply a Service Connection in whole or in part under or within a building except that portion extending through the building wall. When the required length of Service Connection exceeds the foregoing, the Customer shall have the option of terminating his facilities at either (1) a splice box acceptable to the Company installed, owned, and maintained by the Customer at a point within the distance limit described above, or (2) at the discretion of the Company, in the nearest available splice box or manhole provided in and as part of the Company's normal underground distribution system. All connections between the Customer's and Company's facilities shall be made by the Company.

Section 9 - General Interconnect Requirements for On-Site Generation

9.01 The following requirements and standards for connection of generating facilities located on Customer's premises to the Company system shall be met to assure the integrity and safe operation of the Company system with no deterioration to the quality and reliability of service to other Customers. The operation of the generation facility should be done in a competent manner, such that the Company system as a whole is protected.

9.02 All small power producers or cogenerators shall make application to the Company for approval to interconnect their facilities with the Company system.

9.03 The Company shall require the following as part of the application:

(a) Plans and specifications of the proposed installation.
(b) Single line diagram and details of the proposed protection schemes.
(c) Instruction manuals for all protective components.
(d) Component specification and internal wiring diagrams of protective components if not provided in instruction manuals.
(e) Generator data required to analyze fault contributions and load current flows including, but not limited to, equivalent impedances and time constants.
(f) All protective equipment's ratings if not provided in instruction manuals.
(g) Evidence of insurance satisfactory to the Company.
(h) An agreement to indemnify and hold harmless the Company from any and all liability or claim thereof for damage to property, including property of the Company and injury or death to persons resulting from or caused by the presence, operation, maintenance or removal of such installation.

9.04 The Company shall within 30 days from the receipt of all required data from the Applicant either approve or reject in writing the application for connection to the Company system. Rejection of an application shall state with specificity the reasons for such rejection. Connection to the Company system will be permitted only upon obtaining the formal approval of the Company. The Company may require the execution of a formal application form and/or interconnection agreement by the customer.

9.05 The installation of the generation facilities must be in compliance with the requirements of the National Electrical Code and all applicable local, State and federal codes or regulations. The installation shall be undertaken and completed in a workmanlike manner, and shall meet or exceed industry acceptance standards of good practice. The provisions of the National Electrical Safety Code and the standards of the Institute of Electrical and Electronics Engineers, National Electrical Manufacturers Association and the American National Standards Institute shall be observed to the extent that they are applicable. Prior to connection, the Company must be provided with evidence that electrical inspection by an authorized inspection agency indicates that the above items were completed in a manner satisfactory to the Company.

Section 9 - General Interconnect Requirements for On-Site Generation

9.06 The generation facility shall have the following characteristics:

(a) Interconnection voltage shall be compatible and consistent with the system to which the Company determines the generation facility is to be connected.
(b) The generation facility shall produce 60 Hertz sinusoidal output compatible with the Company system to which the facility is to be connected.
(c) The generation facility must provide and maintain automatic synchronization with the Company system to which it is to be connected.
(d) The break point between the generation facilities producing single-phase or three-phase output shall be in accordance with existing Company motor specifications or as otherwise specified by the Company.
(e) At no time shall the operation of the facility result in excessive harmonic distortion of the Company wave form. Total harmonic distortion greater than 5% shall be deemed excessive and shall result in disconnection of the facility from the Company system.
(f) The installation of power factor correction ("PFC") capacitors at the facility may be required under conditions to be determined by the Company when necessary to assure the quality and reliability of service to other Customers. The cost of PFC capacitors shall be borne by the Customer.
(g) The cost of supplying and installing 15-minute integrated generation output metering, and any other special facilities or devices occasioned by the generation facility which the Company may deem necessary on its system, such as telemetry and control equipment, shall be borne by the Customer.

9.07 The Customer shall provide automatic disconnecting devices with appropriate control devices which will isolate the facility from the Company system within a time period specified by the Company for, but not necessarily limited to, the following conditions:

(a) A fault on the Customer's equipment.
(b) A fault on the Company system.
(c) A de-energized Company line to which the customer is connected.
(d) An abnormal operating voltage or frequency.
(e) Failure of automatic synchronization with the Company system.
(f) Loss of a phase or improper phase sequence.
(g) Total harmonic content in excess of 5%.
(h) Abnormal power factor.

The devices shall be so designed and constructed to prevent reconnection of the facility to the Company system until the cause of disconnection is corrected.

9.08 The Company shall reserve the right to specify settings of all isolation devices which are part of the generation facility.

Section 9 - General Interconnect Requirements for On-Site Generation

9.09 The Company shall require initial inspection and testing as well as subsequent inspection and testing of the facility's isolation and fault protection systems at the Customer's expense on an annual basis. Maintenance of these systems must be performed and documented by the customer at specified intervals to the satisfaction of the Company. The Company shall reserve the right to disconnect the customer and/or the generation equipment from the Company system for failure to comply with these inspections, testing and maintenance requirements.

9.10 The Customer is solely responsible for providing adequate protection for the equipment located on the Customer's side of the interconnection system. This protection shall include, but not be limited to, negative phase sequence voltage on three-phase systems.

9.11 The Customer shall provide a Company-controlled disconnecting device providing a visible break on the Company side of the interconnection system. The Company shall require that this device accept a Company-provided padlock. The Company may also require manual operation of the device when required. The Company shall require this device to be labeled "Cogeneration Disconnection Switch" and located outside the facility such that 24-hour access is possible.

9.12 The Customer shall agree to grant access to the Company's authorized representative during any reasonable hours to install, inspect and maintain the Company's metering equipment.

9.13 The Customer must satisfy, and shall be subject to, all terms and conditions of the Company's Tariff for Service.

9.14 No wind generator, tower structure or device shall be installed at a location where, in the event of failure, it can fall in such a manner as to contact, land upon, or interfere with any Company lines or equipment.

9.15 The Customer shall maintain or cause to be maintained the generator and its associated structures, wiring and devices in a safe and proper operating condition so that the installation continues to meet all the requirements contained herein.

9.16 When and if any controversy arises as to the interpretation and application of these requirements and standards, the matter may be referred to the BPU for determination.

9.17 The Company reserves the right to modify or replace the Customer's service meter to prevent reverse registration from the customer's generation facility. Customers desiring to sell power to the Company should refer to Rider QFS - Cogeneration and Small Power Production Service.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.01 General Information: Where a line extension is necessary to provide Service to a Customer or Applicant or group of Customers, and where the request is for an extension of Company facilities to serve new customers, or where the request is for an expansion, upgrade, improvement, or other installation of plant and/or facilities by an Applicant, the procedures set forth in this Section 10 shall be utilized as a guide to determine the extent of any refundable deposit or non-refundable contribution, which may be required from the Customer or Applicant pursuant to NJAC 14:3-8. The Company shall not be precluded from entering into a mutually favorable agreement with the Customer or Applicant when it is deemed that a portion of the investment is for purposes of system improvement. This Section 10 does not apply to installation of special facilities or back-up systems which are not normally supplied by the Company. When such facilities or back-up systems are requested by the Customer, Section 4.05 shall be applicable.

For purposes of this Section 10, the following defined terms are exclusively for use in connection with this Section. Other definitions, as provided in Part I of the Company's Tariff for Service, may also be applicable to any Applicant under this Section and, where appropriate, should be used in conjunction with these terms.

The term "Applicant" means a person or an entity that requests Extension Service from the Company. An Applicant may or may not be the End User or Customer of the Company.

The term "Extension Service" refers to the construction or installation of electric distribution plant and/or facilities by the Company used to convey Service from existing or new plant and/or facilities (and includes the new plant and/or facilities themselves) to a structure or property for which the Applicant has requested Service in response to (i) an application for Extension Service from an Applicant to serve new customer(s) and/or (ii) an application for Extension Service requesting expansion, upgrade, improvement, or other installation of plant and/or facilities to serve existing customer(s). The Extension Service begins at existing plant and/or facilities and ends at the point of connection to or with the Service Connection, and includes the meter.

The term "Extension Cost" refers to the cost of construction and installation of the Extension Service based on the Company's "standard least cost design" criteria, using the Company's unitized or actual cost for materials and labor (both internal and external) employed in the design, construction, and/or installation of the Extension Service, including, but not limited to, Service Connection (subject to Section 8), metering-related costs, and including overheads directly attributable to the work, and the loading factors, such as those for mapping and design. Extension Costs may be apportioned based upon load depending on factors such as the Applicant's needs as compared to the Company's need to enhance or improve reliability, or the needs of other Applicant(s) who may be using the same facilities.

The term "refundable deposit" pertains to the non-interest bearing monies, which must be increased in accordance with Part II, Section 3.14 to provide for the associated income tax liability, that the Applicant must advance prior to the start of construction. The entire refundable deposit amount is subject to refund as set forth herein. Any portion of the refundable deposit remaining after the tenth year of service, as provided in this Section 10, is no longer subject to refund, and becomes the property of the Company. In no event shall more than the original refundable deposit be refunded.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.01 General Information: (Continued)

A “non-refundable contribution," which the Applicant must pay in full prior to construction, becomes the property of the Company and is not subject to refund. All non-refundable contributions must be increased in accordance with Part II, Section 3.14 to provide for the associated income tax liability.

The term "distribution revenues" utilized in this Section 10, as defined by the BPU, shall mean the total revenue, plus related sales and use tax, collected by a regulated entity from a Customer, minus basic generation service charges, plus sales and use tax on the basic generation service charges, and, unless included with basic generation service charges, transmission charges derived from Federal Energy Regulatory Commission (FERC) approved transmission charges, plus sales and use tax on the transmission charges, assessed in accordance with the Company’s Tariff for Service. This definition refers to the total amount of Delivery Service charges (which include Sales and Use Tax) from customer(s), as provided in the applicable rate schedule in Part III of the Company’s Tariff for Service.

The term "underground distribution" refers to buried distribution conductors with associated above-grade equipment.

The term "conventional underground" refers to a secondary network installed in a complete manhole and duct system with all equipment below grade level and is generally located in central sections of the more urban communities.

The term “standard least cost design” refers to the Company’s design criteria for an overhead extension of its facilities, which is based upon then-existing Company specifications as contained in the Company’s Construction Standards, Material Specifications, and Distribution Engineering Practices. These standards are developed in compliance with the current edition of the National Electrical Safety Code in order to provide reliable electric service in a cost-effective manner.

The term “alternate design” refers to an Applicant’s request for Extension Service in a particular manner that exceeds the Company’s “standard least cost design” criteria, including, but not limited to, underground requirements and the removal of existing facilities. An example of an “alternate design” requested by an Applicant would be the installation of a pad-mounted transformer adjacent to a parking lot behind a building, rather than at the front corner closest to the Company’s existing distribution circuit. The difference in cost between the “alternate design” and the “standard least cost design” shall, in all cases, be paid in full by the Applicant as a non-refundable contribution.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.02 Rights-of-Way: The Company shall not be required to extend or relocate its facilities for the purpose of rendering Extension Service to Applicants until rights-of-way or easements satisfactory to the Company have been obtained from government agencies and property owners to permit the installation, operation, and maintenance of the Company's lines and facilities. In connection with granting to, or obtaining for, the Company, without charge, such rights-of-way or easements as necessary for the Company's lines and facilities to be placed upon, over, across, or under property as necessary to provide the Extension Service, Applicants requiring Extension Service shall perform all initial vegetation clearance and trimming. The Company shall also be granted the right to trim or remove vegetation and to remove structures or other obstructions that might subsequently interfere with such lines and facilities, the right of access and entry without notice for Company agents and equipment necessary in the exercise of privileges under the grant, and the right to use and extend the Company's lines and facilities, and install additional lines and facilities, as deemed necessary by the Company in order to provide Service to other Customers. Any right-of-way or permit fees, either initial or recurring, or charges in connection with rights-of-way for providing Extension Service to an Applicant, shall be paid for by the Applicant.

10.03 Extension Service to the Boundary of a Subdivision (Residential and Non-Residential): Such an extension shall normally be provided overhead on public right-of-way and/or private property based upon the Company's standard least cost design criteria, but shall not be provided underground on public right-of-way unless required of, or approved by, the Company.

If the Applicant requests Extension Service that exceeds the Company's standard least cost design criteria, and the Company approves the request, the Applicant shall be required to make a non-refundable contribution equal to the additional cost of the alternate design.

The Company may require a refundable deposit of the Extension Cost, prior to construction, to be refunded as provided in Sections 10.04 or 10.05, as applicable.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.04 Extension Service within a Residential Subdivision: Such an extension shall not be provided overhead. It shall be provided underground based upon the Company's underground design criteria, on public right-of-way and/or private property. This Section is applicable only for new, predominantly residential areas where all the applicable provisions of the Standard Terms and Conditions of this Tariff and any applicable provisions of the New Jersey Administrative Code (NJAC) are complied with.

The Applicant shall make a non-refundable contribution for the construction cost differences between the overhead and the underground design in accordance with Appendix A of Part II of this Tariff.

If the Applicant has not obtained sale contracts for at least 20% of the total units, the Company may require a refundable deposit equal to the Extension Cost using the total unitized cost for the equivalent overhead construction.

Any refundable deposit received from the Applicant will be refunded as follows: One year after the first connection of a completed premise occupied by a bona fide owner or a responsible tenant who has entered into a contract with the Company for Service, the Company will refund a sum equal to ten times total actual distribution revenues from all such bona fide owner(s) or responsible tenant(s) during such contract year, up to (but not in excess of) the refundable deposit amount. Refunds in subsequent years, for up to nine additional years after the first year, will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues that was used for calculating the refund in any previous year, from 2) the total actual distribution revenues from all such bona fide owners or responsible tenants during each such subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

10.05 Extension Service to Serve Non-Residential Customers (including within Non-Residential Subdivisions), Multi-unit Residential Apartment Buildings, and Three-Phase Individual Residential Customers: Such an extension will be provided overhead based upon the Company's standard least cost design criteria, but may be provided underground as an alternate design, but shall not be provided underground on public right-of-way, unless required of, or approved by, the Company. When Extension Service is provided underground pursuant to this Section 10.05, the Applicant, or the Company at the Applicant's discretion (and at the Applicant's own cost and expense consistent with Section 10.01), shall provide all trenching and backfill in accordance with the Company's specifications.

If the Applicant requests Extension Service that exceeds the Company's standard least cost design criteria, and the Company approves the request, the Applicant shall be required to make a non-refundable contribution equal to the additional cost of the alternate design.

The Company may require a refundable deposit equal to the Extension Cost. The refundable deposit under this Section 10.05 shall be eligible for refund, up to (but not in excess of) the refundable deposit amount, as follows: At the end of the first year, the Company will refund from the refundable deposit an amount equal to ten times the total actual distribution revenues billed during that period. At the end of each subsequent year, for an additional nine years, a refund will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues that was used for calculating the refund in any previous year, from 2) the total actual distribution revenues billed during each such subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.06 Extension Service to Serve a Single-Phase, Individual Residential Customer: Such an extension shall be provided overhead based upon the Company's standard least cost design criteria, and may be provided underground as an alternate design, but shall not be provided underground on a public right-of-way. When Extension Service is provided underground pursuant to this Section 10.06, the Applicant shall be required to provide all trenching and backfill in accordance with the Company's specifications.

The difference in cost between the alternate design and the Company's standard least cost design shall be paid in full by the Applicant as a non-refundable contribution.

When provided overhead on a public right-of-way, the Extension Service will be provided without charge or deposit requirement. When provided overhead on private property, the Extension Service will be provided without charge when the Extension Cost, based on the distance measured from the property line to the dwelling location, does not exceed ten times the estimated annual distribution revenues. A refundable deposit may be required from the Applicant for any Extension Cost in excess of ten times the estimated annual distribution revenues.

The refundable deposit under this Section 10.06 shall be eligible for refund, up to (but not in excess of) the refundable deposit amount, as follows: At the end of the first year, the Company will refund from the refundable deposit an amount equal to ten times the total actual distribution revenues billed during that period, less the estimated annual distribution revenues (used as the basis for the initial refundable deposit calculation). At the end of each subsequent year, for an additional nine years, a refund will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues used for calculating the refund in any previous year, from 2) the total actual distribution revenues billed during each subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

10.07 Extension Service within Conventional Underground Area: Such an extension for 600 volt systems necessary on public right-of-way shall be installed without charge or deposit requirement. Such extensions shall not be provided on private property or for other than 600 volt systems.

10.08 Extension Service Initiation: The Company shall not commence construction of the Extension Service until (a) it has received and accepted an application for service; (b) the Applicant has completely executed appropriate contracts for Service, including, but not limited to, Extension Service as set forth in this Section 10; (c) the Applicant has paid any and all associated Extension Costs or other charges, whether by way of a refundable deposit or a nonrefundable contribution as applicable; and (d) the Applicant requesting the Extension Service has furnished to the Company satisfactory rights-of-way over, across, through, in and/or on property that are acceptable to the Company and necessary for the construction, maintenance and operation of the Extension Service.

10.09 Grading Requirements: The Applicant shall perform or arrange and pay for all Company-directed rough grading in accordance with the Company's specifications for underground lines and facilities as said specifications shall be modified by the Company from time to time. The Company's specifications are available from the Company upon request.

10.10 Exceptions: No deviations from the Company's standard construction practices shall be permitted without the Company's approval. Any Company-approved deviations from said construction practices shall be at the Applicant's sole expense.

Section 11 – Third Party Supplier Standards

11.01 Tariff Governs: The Company's BPU-approved Third Party Supplier Agreement and Customer Account Services Master Service Agreement will be governed by reference to this Tariff for Service.

11.02 Uniform Agreement: The Company shall offer the same BPU-approved Third Party Supplier Agreement and Customer Account Services Master Service Agreement to all licensed entities that seek to serve as Alternative Electric Suppliers in the Company's service area by providing electric generation service to Customers located therein.

11.03 Procedure for Agreement Modification: Modifications of the Supplier Fees and Charges contained in the Company's Third Party Supplier Agreement shall be made in accordance with applicable BPU Orders, including the BPU Order dated August 17, 1999 (Docket No. EO97070460). Other modifications to the Company's Third Party Supplier Agreement must be approved by the BPU in accordance with the standards set forth in the aforementioned Order, as follows, or as otherwise directed by the BPU.

The Company shall file a written request for BPU approval of intended modifications (the "Request") with the Board. The date of filing shall be referenced herein as the "Filing Date." A copy of the filing shall simultaneously be provided, by regular mail, facsimile, hand delivery, or electronic means, to the Division of the Ratepayer Advocate, Public Service Electric and Gas, Conectiv, Rockland Electric, and to all BPU-licensed Alternative Electric Suppliers (using a list of addresses for the Alternative Electric Suppliers that shall be maintained by the BPU and made available to the Company). The mode(s) of transmission shall be selected to effectuate actual delivery of the copies within 48 hours of filing with the Board.

Should the Ratepayer Advocate or any BPU-licensed Alternative Electric Supplier wish to contest the Request, the contesting entity must file its reasons for contesting the Request, in writing, with the BPU and simultaneously serve copies thereof upon the Company and the Ratepayer Advocate. This must be done within 17 days of the Filing Date. Service upon the Company shall be made by way of the Company representative who filed the Request.

Within 45 days of the Filing Date, the BPU may issue a Suspension Order stating that the Request requires further study. Such determination would put the Request on hold, pending future action by the Board.

If the BPU does not take action on the Request within 45 days of the Filing Date, the Company may implement the intended modifications, although the BPU retains the authority to make a determination on the Request in the future.

Section 12 – Net Metering Installations

12.01 General: For the purpose of this Section of the Tariff for Service a Customer-generator is an electricity customer such as an industrial, commercial or residential customer that generates electricity using Class 1 renewable resources as defined in NJAC 14:8-1.2 on the customer's side of the meter. Net metering, as defined in Section 12.02 below, provides for the billing or crediting, as applicable, of energy usage by measuring the difference between the amount of electricity delivered by the Company to a Customer-generator, as defined in Section 12.02 below, in a given Billing Month and the electricity delivered by a Customer-generator into the Company distribution system. The Company reserves the right to select and supply the type of meter(s) that will enable the net metering of electricity as described above.

The Customer generator shall be responsible for all interconnection costs as defined in NJAC 14:8-5.7 et seq., which shall be in addition to any other charges applicable to meet service requirements. For customers eligible for Net Metering the term usage as applied in Section 2.05 shall mean net usage as determined by Net Metering. It is the Customer-generator's responsibility to know all of the rules associated with the provision of net metering service.

12.02 Limitations and Qualifications for Net Metering: "Net metering" means a system of metering and billing for electricity in which the Company 1) credits a customer-generator at the full retail rate for each kilowatt-hour produced by a Class 1 renewable energy system installed on the customer-generator's side of the electric revenue meter, up to the total amount of electricity used by that customer-generator during an annualized period determined under NJAC 14:8-4.3 and 2) compensates the customer-generator at the end of the annualized period determined under NJAC 14:8-4.3 for any remaining credits, at a rate equal to the avoided cost of wholesale power. To qualify for Net Metering, a Customer-generator must generate Class 1 renewable energy as defined in NJAC 14:8-1.2. The Company will offer net metering to any customer that generates Class 1 renewable electricity on the customer's side of the meter provided that the generating capacity of the Customer-generator's facility does not exceed the amount of electricity supplied by the Company over an Annualized period (as defined in NJAC 14:8-4.3).

12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)): To qualify for Aggregated Net Metering a customer must be: a state entity, school district, county, county agency, county authority, municipality, municipal agency, or municipal authority that has multiple facilities with metered accounts to be known collectively as the "Aggregated Meters." The Aggregated Meters must be: located within the Company's territory; served under the same rate schedule; all served by either Basic Generation Service or by the same Third Party Supplier; and located within the customer's territorial jurisdiction or, for a State entity, located within 5 miles of one another. One of the Aggregated Meters must operate a Class 1 solar electric power generation system using a net metered account as defined in Section 12.02, Limitations and Qualifications for Net Metering, except for the annualized electric generation capability limitation. The Qualified Customer-Generator must be located on property owned by the customer. The size of the Qualified Customer-Generator for Aggregated Net Metering is defined in Section 12.03.a, Customer-Generator Sizing Qualifications for Aggregated Net Metering.

a) **Customer-Generator Sizing Qualifications for Aggregated Net Metering:** The annualized electric generation capability of the customer's solar generating system, located at the net metered location cannot exceed the amount of electricity supplied by the electric power supplier or basic generation service provider to all of the Aggregated Meters over an annualized period. The Aggregated Meters used to determine the maximum annualized electric generation capability of the customer's solar generating system may not be used to determine the maximum annualized electric generation capability of other aggregated net metered facilities nor become a Qualified Customer-Generator as defined in Section 12.02, Limitations and Qualifications for Net Metering.

Section 12 – Net Metering Installations

12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)): (Continued)

b) **Billing for Aggregated Net Metering**: The Qualified Customer-Generator will be billed as defined in Section 12.06, Net Metering Billing. However, Section 12.06, Net Metering Billing will not apply to the other Aggregated Meters and those meters will continue to be billed at the full retail rate pursuant to the applicable rate schedules.

c) **Incremental Costs Associated with Aggregated Net Metering:** All incremental costs incurred by the Company resulting from the implementation of Aggregated Net Metering shall be recovered from Aggregated Net Metering customers.

12.04 Limitations and Qualifications for Remote Net Metering (BPU Docket No. QO18070697, Order dated September 17, 2018):

The Clean Energy Act, P.L. 2018, Chapter 17, Section 6 required the BPU to establish an application and approval process to facilitate Remote Net Metering in which a public entity certified to act as a host customer with a solar electric energy project may allocate credits to other public entities within the same electric public utility service territory To qualify for Remote Net Metering a customer must be a public entity, which is a State entity, school district, county, county agency, county authority, municipality, municipal agency, municipal authority or public university that has completed the BPU-approved application process and received BPU approval for certification as a participant eligible to receive Remote Net Metering credits. A host customer is a public entity that proposes to host a solar electric generation facility on its property. The entities designated to receive credits are considered to be receiving customers that are public entities located in the same electric distribution company (“EDC”) territory as the host customer. Both the host customer and the receiving customer must be a customer of record of JCP&L, and there may be no more than ten receiving customer accounts per host.

Eligible public entities must follow the established application and approval process to certify public entities to act as a host customer for Remote Net Metering, requiring submittal of the BPU-approved form of “Public Entity Certification Agreement” used by the host customers and receiving customers which shall be fully executed and provided to the Company, reviewed by the Staff of the BPU and approved by the BPU prior to the application of any Remote Net Metering credits. The Public Entity Certification Agreement is available on the New Jersey Clean Energy Program website as well as the Company’s website in the section dedicated to information regarding net metering and interconnection processes. The standard form “Public Entity Certification Agreement’ must be fully executed by the host customer and each receiving customer, be accompanied by the BPU-approved standard form of Interconnection Application (Part 1) as used for all net metered projects and be delivered to both BPU Staff and the Company. The Company and BPU Staff will review the Public Entity Certification Agreement for administrative completeness. Within 10 days, the Company will provide its input to BPU Staff, whereupon BPU Staff will issue a notice of its findings to the contact person listed on the form. Following the issuance of a notice of administrative completeness, the Company will have twenty business days to review the application for eligibility and feasibility, including the proposed system size and all account information and make a recommendation to BPU Staff to approve or deny. In the case of a recommendation of denial, the Company will provide to BPU Staff a description of the deficiencies and potential means to correct the deficiencies. BPU Staff will present the fully executed “Public Entity Certification Agreement” and Part 1 of the Interconnection application to the BPU with a recommendation for approval or denial.

Section 12 – Net Metering Installations

a) **Host Customer Solar Electric Generator Sizing for Remote Net Metering:** The size of a host customer's solar electric generation facility shall be limited to the installed capacity that can produce electricity on an annual basis in an amount not to exceed the total average usage of the host customer's electric accounts with the Company. The host customer is not required to use more than one account for purposes of sizing the solar electric generation facility. However, the solar facility must be located on property containing at least one Company electric meter for the host customer. The host customer is required to identify which account(s) to use to calculate the total average usage for the previous twelve months of consumption in kWhs. The total quantity of annual, historic consumed kWh will be divided by (i) the number of accounts, if more than one account is used, and (ii) 1,200 annual kWh per kilowatt ("kWdc") to arrive at the maximum capacity for the solar electric generation facility in kWs.

Billing and Credits for Remote Net Metering: No more than ten receiving accounts may be party to a Public Entity Certification Agreement and not less than 10% of the solar electric generating facility output may be allocated to an individual receiving account. The terms and conditions of the Public Entity Certification Agreement, including all designated receiving accounts and their associated percentage of output allocations, shall be fixed throughout the annualized period with the exception of a once per annum opportunity to reallocate upon BPU Staff's approval of a revision to a Public Entity Certification Agreement, which is re-executed with all parties' approval, including the Company. The host customer shall agree to the installation of a revenue grade production meter at its expense as specified by the Company, to record the solar generation at the host site. On a monthly basis, the Company shall use the metered kWh data produced by the solar electric generation facility on the host customer property to calculate the credits due to receiving customers. The monthly output will be allocated to receiving customers according to the percentage allotments indicated on the Public Entity Certification Agreement. The value of a Remote Net Metering credit will reflect a rough approximation of the generation, transmission and distribution value of a kWh produced by the solar electric generation facility. Each credited kWh for a receiving customer shall offset the variable kWh charges of a receiving customer(s) except for the SBC charge. No fixed, demand ($/kW), customer or SBC charges shall be offset by a remote net metering credit. On a monthly basis, the Company will credit an apportioned amount of kWh output from the solar facility in the form of kWh to be deducted from the kWh consumed by the receiving to receiving customers according to the percentage allotments indicated on the Public Entity Certification Agreement. The value of a Remote Net Metering credit will reflect a rough approximation of the generation, transmission and distribution value of a kWh produced by the solar electric generation facility. Each credited kWh for a receiving customer shall offset the variable kWh charges of a receiving customer(s) except for the SBC charge. No fixed, demand ($/kW), customer or SBC charges shall be offset by a remote net metering credit. On a monthly basis, the Company will credit an apportioned amount of kWh output from the solar facility in the form of kWh to be deducted from the kWh consumed by the receiving customer. The apportioned amount of solar electricity generated in kWh, the gross amount of electricity consumed and the net amount of kWh after credit allocation will be identified on the monthly electric bills of the designated receiving customer account. The receiving customers will be charged the SBC amounts attributable to the apportioned credit kWh. The application of an annualized period as currently used in the net metering rules at N.J.A.C. 14:8-4.2 shall apply to remote net metering. Any excess generation for an individual receiving customer account after a monthly credit allocation shall be carried over to the next month within the annualized period. If an individual receiving customer account holds credits at the end of an annualized period, the account shall be trued up consistent with current net metering practice, with excess kWh compensated at the average annual LMP in the Company's transmission zone.

b) **Incremental Costs Associated with Remote Net Metering:** All incremental costs incurred by the Company resulting from the implementation of Remote Net Metering shall be recovered from Remote Net Metering customers.

Section 12 – Net Metering Installations

12.05 Installation Standards: A Customer-generator shall comply with the requirements of the Company which are set forth in detail in the Application/Agreement Parts 1 and 2 for Level 1 Projects or the Interconnection Application and Agreement for Level 2 or Level 3 Projects both of which are approved by the New Jersey Office of Clean Energy and available at www.firstenergycorp.com. In addition, the Customer-generator shall be responsible for meeting all applicable safety and power quality standards as set forth below.

The Customer-generator's facility shall comply with all applicable safety and power quality standards specified by the National Electrical Code, Institute of Electrical and Electronics Engineers, and accredited testing institutions, such as Underwriters Laboratories. The Customer-generator's facility should be constructed and installed in accordance with the State of New Jersey Uniform Construction Code requirements for electrical installations, UL 1741 and the IEEE Standard 1547. Net Metering systems served by network distribution systems, shall comply with standards established by the Company and approved by the BPU in addition to the aforementioned applicable safety and power quality standards and all other requirements in NJAC 14:8-5.2 et seq

12.06 Initiation of Service: Prior to interconnecting with the Company's distribution system the Customer-generator is required to provide the Company with an Interconnection Application/Agreement Parts 1 and 2 for Level 1 projects or an Interconnection Application and Agreement for Level 2 or Level 3 Projects and must also pay all appropriate charges as detailed in these applications. Additionally, the Company may, at its option, inspect the interconnection prior to the initiation of Net Metering service.

Initiation of service will become effective on the Customer-generator's first regularly scheduled meter reading date that is at least twenty (20) days after the Customer-generator elects to take service under or to be billed under or in accordance with this provision, by executing an Interconnection Application, but in no case prior to the installation of the necessary meter(s), and shall terminate at a regularly scheduled meter reading date that is at least twenty (20) days following the receipt by the Company of Customer-generator's notification of termination or from the date that the Company determines that the customer-generator is no longer eligible for net metering service pursuant to NJAC 14:8-4.1 et seq.

12.07 Net Metering Billing: In any Billing Month during an Annualized period, where the amount of electricity delivered by the Customer-generator plus any kilowatt-hour credits held over from the previous Billing Month or Billing Months exceeds the electricity supplied by the Customer-generator's electric supplier or basic generation service provider, as applicable, the excess kilowatt-hours shall be credited to the Customer-generator in the next Billing Month during the Annualized period. At the end of the Annualized period, the Customer-generator will be compensated for any remaining credits by the Customer-generator's electric supplier or basic generation service provider, as applicable, at the avoided cost of wholesale power (as defined at NJAC 14:8-4.2).

A Customer-generator shall have a one-time opportunity to select a Billing Month as the start of the Customer-generator's Annualized period. This selection will become effective on the first regularly scheduled meter reading date that is at least twenty (20) days after the Customer-generator notifies the Company of the Customer-generator's selection under the one-time opportunity provided in NJAC 14:8-4.3 (f) – (j).

In the event that a Customer-generator changes suppliers, the electric power supplier or basic generation service provider with whom service is terminating shall treat the end of the service period as if it were the end of the Annualized period and shall compensate the Customer-generator for any remaining credits at the avoided cost of wholesale power.

12.08 Program Availability: The Company may be authorized by the BPU to cease offering net metering whenever the total rated generating capacity owned and operated by Customer-generators on a Statewide basis equals 5.8 percent of total annual kilowatt-hour sales in the State.

Section 13 – Community Solar Energy Pilot Program

13.01 General:

The Community Solar Energy Pilot Program is open to customers of all rate classes who subscribe to solar projects that are approved by the BPU. Projects and customer subscribers to those approved projects must meet the following minimum requirements, and the full requirements defined in N.J.A.C. 14:8-9.1, *et seq.*, in accordance with N.J.S.A. 48:3-87.11. The program provides for the participation of customers of the Company in all rate classes as subscribers to BPU-approved solar projects that are located within the service territory of the Company, but may be remotely located from the subscriber's electric service address, and receive a credit on their utility bills in accordance with their participation share. Existing solar projects may not apply to requalify as a Community Solar Energy Pilot Program project. The Pilot Program shall run for a period of no more than 36 months, divided into Program Year 1 (PY1), Program Year 2 (PY2), and Program Year 3 (PY3). PY1 shall begin February 19, 2019, and last until December 31, 2019. Subsequent program years shall begin on January 1 and last for the full calendar year. For each of the three program years, BPU staff shall initiate an annual application process. The annual capacity limit in the Company's service territory each year shall be approximately 20.625 MW based upon its 27.5% share of the 75 MW available statewide capacity. Any unallocated capacity at the end of a program year may be reallocated to subsequent program years. At least 40 percent of the annual capacity limit shall be allocated to low and moderate income community (LMI) projects. The application and criteria for selection of projects is managed by the BPU. Only projects that are selected by the BPU will be eligible to participate in the program. The capacity limit for individual community solar pilot projects is set at a maximum of five MWs per project, measured as the sum of the nameplate capacity in DC rating of all PV panels comprising the community solar facility. The minimum number of participating subscribers for each community solar project shall be set at 10 subscribers and the maximum number of participating subscribers for each community solar project shall be set at 250 subscribers per one MW installed capacity (prorated to project capacity). Each project must be equipped with at least one utility grade meter to facilitate the recording of solar generation underlying the bill credit process.

13.02 Selected Definitions (N.J.A.C. 14:8-9.2):

"Community solar pilot project," "community solar project," or "project" refers to a community solar project approved by the BPU for participation in the Pilot Program, including, but not limited to, the community solar facility, project participants, and subscribers.

"Community solar subscriber organization" or "subscriber organization" means the entity, duly registered with the BPU that works to acquire original subscribers for the community solar project and/or acquires replacement subscribers over the lifetime of the community solar project and/or manages subscriptions for a community solar project. The community solar subscriber organization may or may not be, in whole, in part, or not at all, organized by the community solar developer, community solar owner, or community solar operator.

"Community solar subscriber" or "subscriber" refers to any person or entity who participates in a community solar project by means of the purchase or payment for a portion of the capacity and/or energy produced by a community solar facility. One electric meter denotes one subscriber.

"Community solar subscription" or "subscription" refers to an agreement to participate in a community solar project, by which the subscriber receives a bill credit for a portion of the community solar capacity and/or energy produced by a community solar facility. A subscription may be measured as capacity in kW and/or energy in kWh, ownership of a panel or panels in a community solar facility, ownership of a share of a community solar project, or a fixed and/or variable monthly payment to the project operator.

Section 13 – Community Solar Energy Pilot Program

13.03 Subscription Requirements:

Community solar pilot project subscriptions shall not exceed 100 percent of the subscriber's historic annual usage, calculated over the past 12 months, available at the time of the application. In cases where a 12-month history is not available, the community solar subscriber organization shall estimate, in a commercially reasonable manner, a subscriber's load based on available history. No single subscriber shall subscribe to more than 40 percent of a community solar project's total annual net energy. Subscriptions are portable, provided that the subscriber remains within the original Company service territory as the community solar pilot project to which they are subscribed. Appropriate notice of the change in residence and/or location must be provided to the Company, no later than 30 days after the effective date of the change in residence and/or location. In cases of relocation, subscribers are entitled to one revision per move to their subscription size to account for a change in average consumption. Subscriptions may be sold or transferred back to the project owner or community solar subscriber organization by subscribers as specified in their subscription agreements. Subscribers may not sell or transfer a subscription to another party other than the project owner or community solar subscriber organization. A subscriber may not participate in more than one community solar project. It is the responsibility of the subscriber organization to verify that their subscribers are not already subscribed to another community solar project.

13.04 Community Solar Bill Credits

Participating subscriber customers will receive a dollar-based bill credit for their subscribed percentage of the monthly kilowatt-hour output of the community solar project in proportion to the subscriber's share of the community solar project as indicated on the most recent list received from the subscriber organization. The monthly dollar credit on the subscriber’s bill will be the equivalent of their subscription percentage of the community solar project monthly kilowatt-hour generation amount applied to all kilowatt-hour charges on the subscriber’s bill, excluding all fixed and non-by-passable charges and SUT. The non-bypassable charges are the fixed monthly customer charge, all kW demand charges (if applicable), the SBC charge, the NGC charge and the ZEC charge. The value of the bill credit shall be set at the weighted class average retail rate for their respective service classification. The bill credit for CIEP eligible customers will be set at the average hourly energy price. Customers served by a third-party supplier will have their clscredit based upon the BGS rate. The subscriber’s bill credit will be used to offset the subscriber’s total bill up to the amount of actual metered consumption. The calculation of the value of the bill credit shall remain as described above and shall remain in effect for the life of the project, defined as no more than 20 years from the date of commercial operation of the project or the period until the project is decommissioned, whichever comes first, in addition to any modifications subsequently ordered by the BPU. The community solar bill credit will be specifically identified as the community solar bill credit in a separate line on the subscribers' utility bills.

Section 13 – Community Solar Energy Pilot Program

13.04 Community Solar Bill Credits (Continued

An annualized period shall be established for each subscriber. The annualized period shall begin on the day a subscriber first earns a community solar bill credit based on the delivery of energy, and continues for a period of 12 months, until the subscription ends, or until the subscriber's Company account is closed, whichever occurs earlier. The Company may sync up the monthly billing period of subscribers and projects, by modifying, with due notice given, the monthly billing period for subscribers upon their first month of participation in the community solar project. Excess credits above the level of the metered monthly consumption shall carry over from monthly billing period to monthly billing period, with the balance of credits accumulating until the earlier of either the end of the annualized period, the closure of the subscriber's Company account, or the end of the subscriber's community solar subscription. At the end of the annualized period and/or when a subscriber's Company account is closed and/or at the end of the subscriber's community solar subscription, any excess net bill credits greater than the sum of all appropriate billable charges shall be compensated at the Company's average LMP of the JCP&L transmission zone. The excess compensation must be returned to the subscriber by bill credit, wire transfer, or check. If a subscriber receives net excess credits for each of the three previous consecutive years, the subscriber organization must resize the subscriber's subscription size to ensure it does not exceed 100 percent of historic annual usage, calculated over the past 12 months, available at the time of the reassessment.

Any generation delivered to the grid that has not been allocated to a subscriber may be "banked" by the project operator in a dedicated project Company account for an annualized period of up to 12 months. The banked credits may be distributed by the project operator to any new or existing subscriber during that 12-month period, in conformance with subscription requirements set forth in N.J.A.C. 14:8-9.6. At the end of the up to 12-month period, any remaining generation credits shall be compensated at the Company's average LMP of the JCP&L transmission zone. Subscribers must have an active electric account within the Company's service territory of the community solar project to which they are subscribed. Upon Company request, If required by the Company, subscribers must agree to a remote read smart meter upon EDC request, purchased and installed at EDC cost.

The Company will utilize a standardized process for sharing subscriber information between subscriber organizations and the Company by which subscriber organizations can submit the lists of subscribers. Subscriber organizations shall send to the Company a list of subscribers to the project with all appropriate subscriber information, no later than 60 days prior to the first monthly billing period for the community solar project. Additionally, subscriber organizations shall send an updated list to the Company once per month.

Appendix A - Unit Costs of Underground Construction
Single Family Developments

Appendix A - Residential Electric Underground Extensions
The Applicant shall pay the Company the amount determined from the following table:

A. Base Charges

	Average Front Footage Per Lot			
1. Single Family	<= 125 Ft	126-225 Ft	226-325 Ft	>= 326Ft
Nonrefundable charge per building lot				
• With Applicant providing all trenching and road crossing conduits	$ 361.00	$ 428.00	$ 495.00	$ 881.00
Refundable deposit based on equivalent overhead construction	$ 828.00	$1,656.00	$2,484.00	$4,140.00

2. Lots requiring 1Φ primary extension
   - Without primary enclosure $1,532.00
   - With primary enclosure $4,236.44

3. Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 KVA, etc. — Charge to be based on differential cost according to unit costs specified in Exhibits I through III

B. Additional Charges

1. Street Lights - SVL
   - 16 foot fiberglass pole with standard colonial post top luminaire .... $ 365.00
   - 16 foot fiberglass pole with ornate colonial post top luminaire $1,026.00
   - 30 foot fiberglass pole with cobra head luminaire on 6 foot bracket $1,126.00
   - 12 foot 9 inch ornate fiberglass pole with ornate colonial post top luminaire $2,567.00
   - 12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire $3,234.00
   - LED
   - 16 foot Fiberglass pole with colonial post top luminaire………………………………$ 577.00
   - 30 foot fiberglass pole with Cobra Head……………………………………………………$1,164.00
   - 12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire…………….$2,118.00

2. Multi-Phase Construction $1.28 per added phase per foot

3. Pavement cutting and restoration, rock removal, blasting, difficult digging, and special backfill — At actual low bid cost with option of Applicant to contract for as limited by NJAC

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit I - Unit Costs of Underground Construction
Single-Phase 15 kV

	Item	Unit	Total Cost
1.	Primary cable 1/0 aluminum	per foot	3.86
2.	Secondary cable 3/0 aluminum	per foot	2.48
	350 MCM aluminum	per foot	5.02
	500 MCM aluminum	per foot	8.09
	750 MCM aluminum	per foot	11.04
3.	Service - 200 amp and below	per foot	2.48
	50 feet complete	each	614.14
4.	Primary termination - branch	each	1,372.50
5.	Primary junction enclosure - branch	each	2,703.80
6.	Secondary enclosure	each	646.61
7.	Conduit - 3 inch PVC	per foot	3.94
	Conduit - 4 inch PVC	per foot	4.75
8.	Street light cable - # 12 cu. duplex	per foot	2.93
9.	Transformers - including fiberglass pad		
	25 kVa – single-phase	each	2,616.27
	50 kVa – single-phase	each	2,921.40
	75 kVa – single-phase	each	3,305.99
	100 kVa – single-phase	each	3,680.90
	167 kVa – single-phase	each	4,386.08
	25 kVa – single-phase Dual Voltage	each	3,035.23
	50 kVa – single-phase Dual Voltage	each	3,299.85
	75 kVa – single-phase Dual Voltage	each	4,093.62
10.	Street light poles		
	16 foot post top fiberglass pole	each	576.58
	30 foot fiberglass pole	each	1,163.74
	12 foot 9 inch ornate fiberglass pole	each	2,117.95
11.	Street light luminaire – cobra head SVL	each	539.26
12.	Post top luminaire – SVL		
	50, 70, 100 & 150 watt colonial style	each	365.76
	70 & 100 watt ornate colonial style	each	1,026.42
	70 & 100 watt ornate acorn style	each	1,693.36
13.	Primary splice – # 2 aluminum	each	188.84

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit II - Unit Costs of Underground Construction
Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Primary cable – three-phase main feeder	per foot	$ 24.93
2.	Secondary cable - 4-wire 350 MCM aluminum	per foot	8.60
3.	Service cable - 4-wire 350 MCM aluminum	per foot	8.92
4.	Primary termination - main		
	# 2 aluminum three-phase	each	3,365.54
	1000 MCM aluminum three-phase	each	4,961.19
5.	Primary junction - main	each	4,660.04
6.	Primary switch - main		
	PMH-9	each	34,679.04
	PMH-10	each	30,136.80
	PMH-11	each	31,658.44
	PMH-12	each	38,639.32
7.	Conduit - 5 inch PVC	per foot	5.98
	- 6 inch PVC	per foot	7.40
8.	Transformers - including concrete pad		
	75 kVa three-phase	each	6,297.08
	150 kVa three-phase	each	6,980.84
	300 kVa three-phase	each	8,835.18
	500 kVa three-phase	each	10,988.05
9.	Primary splice – 15 kV three-phase cable	each	433.75

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit III - Unit Costs of Overhead Construction
Single and Three-Phase 15 kV

Item	Unit	Total Cost
1. Pole line (including 40 foot poles, anchors & guys)	per foot	$ 6.56*
2. Primary wire		
Single-phase – branch	per foot	2.58
Three-phase – main	per foot	12.08
3. Primary wire - neutral	per foot	2.42
4. Secondary cable		
Three-wire	per foot	5.16
Four-wire	per foot	8.45
5. Service		
Single-phase	each	244.60
Single–phase - 200 amp and below	per foot	2.49
Three-phase – up to 200 amp	per foot	4.02
Three-phase – over 200 amp	per foot	6.67
6. Transformers		
25 kVa – single-phase	each	1,453.17
50 kVa – single-phase	each	1,763.05
75 kVa – single-phase	each	2,273.13
100 kVa – single-phase	each	2,635.99
167 kVa – single-phase	each	3,073.14
3- 25 kVa – three-phase	each	3,818.97
3- 50 kVa – three-phase	each	4,748.61
3- 75 kVa – three-phase	each	6,404.91
3-100 kVa – three-phase	each	7,481.49
3-167 kVa – three-phase	each	8,792.94
7. Street light luminaire – cobra head SVL	each	577.38

Pole line cost to be used = $6.56 / 2 = $3.28

Note: All charges are subject to taxes as provided in Section 3.14.

Appendix A - Exhibit III - Unit Costs of Overhead Construction
Single and Three-Phase 15 kV

Item		Unit	Total Cost
8. Street light luminaire – LED – Contributions			
Monthly Contribution Fixture charge of $2.92			
30 W	Cobra Head	each	358.38
50 W	Cobra Head	each	354.88
90 W	Cobra Head	each	403.55
130 W	Cobra Head	each	492.97
260 W	Cobra Head	each	694.22
50 W	Acorn	each	1,295.80
90 W	Acorn	each	1,243.30
50 W	Colonial	each	619.38
90 W	Colonial	each	793.88
Monthly Contribution Fixture charge of $4.68			
30 W	Cobra Head	each	209.20
50 W	Cobra Head	each	205.70
90 W	Cobra Head	each	254.37
130 W	Cobra Head	each	343.79
260 W	Cobra Head	each	545.04
50 W	Acorn	each	1,146.62
90 W	Acorn	each	1,094.12
50 W	Colonial	each	470.20
90 W	Colonial	each	644.70

Note: All charges are subject to taxes as provided in Section 3.14.

TARIFF for SERVICE

Part III

Service Classifications and Riders

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

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SERVICE CLASSIFICATIONS AND RIDERS
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Service Classification RS
Residential Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RS is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RT. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT): All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.008758** per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $4.11** per month
Supplemental Customer Charge: $2.14 per month Off-Peak/Controlled Water Heating

2) **Distribution Charge:**

June through September:
$0.020356 per KWH for the first 600 KWH (except Water Heating)
$0.080494 per KWH for all KWH over 600 KWH (except Water Heating)

October through May:
$0.033345 per KWH for all KWH (except Water Heating)

Water Heating Service:
$0.022255 per KWH for all KWH for Off-Peak Water Heating
$0.029312 per KWH for all KWH for Controlled Water Heating

Service Classification RS
Residential Service

3) **Non-utility Generation Charge (Rider NGC)**
See Rider NGC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

6) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, a contract of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

Service Classification RS
Residential Service

SPECIAL PROVISIONS:

(a) Restricted Off-Peak Water Heating Service: Locations currently receiving service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications, shall be billed a Supplemental Customer Charge, and shall have the KWH used during the off-peak hours of 8 PM to 8 AM Eastern Standard Time measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.09)

(b) Restricted Controlled Water Heating Service: Locations currently receiving service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications and have the operation of both upper and lower elements restricted by Company control devices to the hours of 11 PM to 4 PM Eastern Standard Time, shall be billed a Supplemental Customer Charge, and shall have the KWH used during those hours measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.10)

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification RT
Residential Time-of-Day Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RT is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RS. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.008758** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $8.69** per month
Solar Water Heating Credit: $2.18 per month

2) **Distribution Charge:**
$0.058665 per KWH for all KWH on-peak for June through September
$0.043092 per KWH for all KWH on-peak for October through May
$0.027404 per KWH for all KWH off-peak

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

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Service Classification RT
Residential Time-of-Day Service

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM Eastern Standard Time, Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high density areas. The off-peak hours will not, however, be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, contracts of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

SPECIAL PROVISION: Solar Water Heating Systems: For customers who install a solar water heating system with electric backup, the monthly Customer Charge shall be reduced by the credit provided above.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification RGT
Residential Geothermal & Heat Pump Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RGT is available for residential customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, who have one of the following types of electric space heating systems as the primary source of heat for such structure or unit and which system meets the corresponding energy efficiency criterion:

Geothermal Systems with Energy Efficiency Ratio (EER) of 13.0 or greater;
Heat Pump Systems with Seasonal Energy Efficiency Ratio (SEER) of 11.0 or greater, and a Heating Season Performance Factor (HSPF) which meets the then current Federal HSPF standards;
Room Unit Heat Pump Systems with Energy Efficiency Ratio (EER) of 9.5 or greater.

Service Classification RGT is not available for customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, which have an electric resistance heating system as the primary source of space heating for such structure or unit.

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge:**
$0.008758 per KWH for all KWH on-peak and off-peak for June through September
$0.008758 per KWH for all KWH for October through May

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $8.69** per month

2) **Distribution Charge:**

June through September:
$0.058665 per KWH for all KWH on-peak
$0.027404 per KWH for all KWH off-peak

October through May:
$0.033345 per KWH for all KWH

Service Classification RGT
Residential Geothermal & Heat Pump Service

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM Eastern Standard Time, Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high-density areas. The off-peak hours will not, however, be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, contracts of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GS
General Service Secondary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GS is available for general service purposes at secondary voltages not included under Service Classifications RS, RT, RGT or GST.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT): All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge:**
$0.008758 per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$ 4.28** per month single-phase
$15.33 per month three-phase

Supplemental Customer Charge: **$ 2.14** per month Off-Peak/Controlled Water Heating
$ 3.50 per month Day/Night Service
$15.94 per month Traffic Signal Service

2) **Distribution Charge:**

KW Charge: (Demand Charge)

$ 9.24 per maximum KW during June through September, in excess of 10 KW
$ 8.60 per maximum KW during October through May, in excess of 10 KW
$ 4.19 per KW Minimum Charge, in excess of 10 KW

Service Classification GS
General Service Secondary

KWH Charge:
June through September (excluding Water Heating and Traffic Signal Service):
$0.075557 per KWH for all KWH up to 1000 KWH
$0.006042 per KWH for all KWH over 1000 KWH

October through May (excluding Water Heating and Traffic Signal Service):
$0.069910 per KWH for all KWH up to 1000 KWH
$0.006042 per KWH for all KWH over 1000 KWH

Water Heating Service:
$0.022255 per KWH for all KWH Off-Peak Water Heating
$0.029312 per KWH for all KWH Controlled Water Heating

Traffic Signal Service:
$0.015834 per KWH for all KWH

Religious House of Worship Credit:
$0.038519 per KWH for all KWH up to 1000 KWH

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

7) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

9) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

Service Classification GS
General Service Secondary

DETERMINATION OF DEMAND: The KW used for billing purposes shall be the maximum 15-minute integrated kilowatt demand during each billing month calculated to the nearest one-tenth KW. In instances where the Company has determined that the demand will not exceed 10 KW, and has therefore elected to not install a demand meter, the demand shall be considered less than 10 KW for billing purposes. Where Service is rendered under Special Provision (a), the on-peak demand shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours of 8 AM to 8 PM prevailing time, Monday through Friday each billing month, while the off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

Service Classification GS
General Service Secondarv

SPECIAL PROVISIONS:

(a) Day/Night Service: Customers who normally operate in such manner that their maximum demands do not occur during the Company's on-peak period and elect to receive Service under this Special Provision shall have their monthly demand charge under this Service Classification based upon the greater of: (a) the maximum on-peak demand created during the month; or (b) 40 percent of the maximum off-peak demand created during the month. For the monthly KW Minimum Charge calculation, the Customer's demand will be based on the greater of: (a) the maximum on-peak demand created during the current and preceding eleven months; or (b) 40 percent of the maximum off-peak demand created during the current and preceding eleven months (but not less than the Contract Demand). Customers served under this Special Provision shall be billed an additional Supplemental Customer Charge provided above.

(b) Restricted Commercial and Industrial Space Heating Service: Customers served as of February 6, 1979, who have (1) electricity as the sole primary source of energy for space heating the entire structure(s) as well as for lighting, power, cooking, refrigeration, water heating, and similar purposes except for incidental special applications or purposes where electrical energy cannot reasonably be used; (2) the sum of the connected loads for lighting, space heating, cooking, and water heating exceed 50% of the total connected load; and (3) at least 50% of the total electrical load is located in a structure(s) heated by electricity; shall have the monthly KW Minimum Charge calculation modified such that the Customer's demand will be based on the highest demand established in the summer billing months only.

(c) Traffic Signal Service: Customers receiving service for traffic signal installations shall be billed an additional monthly Supplemental Customer Charge and the KWH Charges provided above.

(d) Restricted Off-Peak Water Heating Service: Locations currently receiving Service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications, shall be billed a Supplemental Customer Charge, and shall have the KWH used during the off-peak hours of 8 PM to 8 AM Eastern Standard Time measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.09)

(e) Restricted Controlled Water Heating Service: Locations currently receiving Service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications and have the operation of both upper and lower elements restricted by Company control devices to the hours of 11 PM to 4 PM Eastern Standard Time, shall be billed a Supplemental Customer Charge, and shall have the KWH used during those hours measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.10)

(f) Religious Houses of Worship Service: When electric service is supplied to a customer where the primary use of service is for public religious services and the customer applies for and is eligible for such Service, the customer's monthly Distribution Charge will be subject to a KWH Credit provided above for the first 1000 KWH usage per month. The Customer will be required to sign an Application for Religious Houses of Worship Service certifying eligibility. Upon request by Company, the Customer shall furnish satisfactory proof of eligibility for Service under this Special Provision.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

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Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification GS
General Service Secondary

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification GST
General Service Secondary Time-Of-Day

APPLICABLE TO USE OF SERVICE FOR: Service Classification GST is available for general Service purposes for commercial and industrial customers establishing demands in excess of 750 KW in two consecutive months during the current 24-month period. Customers which were served under this Service Classification as part of its previous experimental implementation may continue such Service until voluntarily transferring to Service Classification GS.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge: $0.008758** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$41.79** per month single-phase
$59.62 per month three-phase

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 9.82 per maximum KW during June through September
$ 9.18 per maximum KW during October through May
$ 4.29 per KW Minimum Charge

KWH Charge:
$0.005700 per KWH for all KWH on-peak
$0.005700 per KWH for all KWH off-peak

Service Classification GST
General Service Secondary Time-Of-Day

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

9) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

Service Classification GST
General Service Secondary Time-Of-Day

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GST
General Service Secondary Time-Of-Day

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification GP
General Service Primary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GP is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Single or three-phase service at primary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**

2) **Transmission Charge: $0.005721** per KWH for all KWH

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $70.65** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 7.37 per maximum KW during June through September
$ 6.83 per maximum KW during October through May
$ 2.50 per KW Minimum Charge

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.47 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.003973 per KWH for all KWH on-peak and off-peak

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off peak

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

9) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

Service Classification GP
General Service Primary

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 a.m. to 8 p.m. prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

DISCONNECTION / RECONNECTION CHARGES: Charges for all disconnections and reconnections shall be based upon actual costs. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Issued: **Effective**

Filed pursuant to Order of Board of Public Utilities
Docket No. dated

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification GP
General Service Primary

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification GT
General Service Transmission

APPLICABLE TO USE OF SERVICE FOR: Service Classification GT is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Three-phase service at transmission voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**

2) **Transmission Charge: $0.005015** per KWH for all KWH
$0.001156 per KWH for all KWH High Tension Service

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $303.43** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 4.73 per maximum KW
$ 1.26 per KW High Tension Service Credit
$ 3.13 per KW DOD Service Credit

KW Minimum Charge: (Demand Charge)
$ 1.43 per KW Minimum Charge
$ 0.95 per KW DOD Service Credit
$ 0.60 per KW Minimum Charge Credit

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.46 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.003056 per KWH for all KWH on-peak and off-peak
$0.001084 per KWH High Tension Service Credit
$0.001986 per KWH DOD Service Credit

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak – excluding High Tension Service
See Rider NGC for rate per KWH for all KWH on-peak and off-peak – High Tension Service

4) **Societal Benefits Charge (Rider SBC)**:
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

Service Classification GT
General Service Transmission

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Storm Recovery Charge (Rider SRC)**:
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

9) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

MINIMUM CHARGE PER MONTH: The monthly KW Charge (Demand Charge) under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand). When the maximum on-peak demand created in the current and preceding eleven months has not exceeded 3% of the maximum off-peak demand created in the current and preceding eleven months, the KW Minimum Charge specified above shall be reduced by the KW Minimum Charge Credit stated above.

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

DISCONNECTION / RECONNECTION CHARGES: Charges for all disconnections and reconnections shall be based upon actual costs. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Service Classification GT
General Service Transmission

RECONNECTIONS WITHIN 12-MONTH PERIOD: (Continued)
Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

SPECIAL PROVISIONS:

(a) Commuter Rail Service: Where service is supplied to traction power accounts for a commuter rail system, such accounts shall be conjunctively billed based upon coincident demands. This Special Provision also modifies the DEFINITION OF ON-PEAK AND OFF-PEAK HOURS for Demand Charge purposes only, such that the following Federal Holidays are considered off-peak the entire day: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. In addition, the periods from 8 AM to 10 AM and from 5 PM to 8 PM prevailing time Monday through Friday shall be considered as off-peak for Demand Charge purposes only. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change.

Where traction power is supplied at high tension (230 KV) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining billing demand.

(b) High Tension Service: Where service is supplied at 230 KV, the determination of KW and KVAR demands shall be modified to refer to 60-minute demands, and the Distribution KW and KWH Charges, except for KW Minimum Charge, shall be reduced by the High Tension Service Credits provided above to reflect the reduced line losses associated with service at this voltage level. Any Customer taking this Special Provision shall not be qualified for Special Provisions (c) and (d) below.

(c) Department of Defense Service: Where service is supplied to the major military installations of the United States Department of Defense at transmission voltages, the Distribution KW Charge, KW Minimum Charge and KWH Charge shall be reduced by the DOD Service Credits provided above.

(d) Closing of GTX Service: Upon the closing of Service Classification GTX effective April 1, 2004, for any GTX customer as of August 1, 2003 where service is supplied at 230 KV, the monthly billing demand shall be the maximum 60-minute integrated kilowatt demand created during all on-peak and off-peak hours of the billing month and the Distribution KW Charge (Demand Charge) shall be $0.47 per KW ($0.50 per KW including SUT). The Distribution KW Minimum Charge, KVAR Charge and KWH Charge provided above shall not apply, and the Non-utility Generation Charge shall be the lesser of (1) $0.000312 per KWH ($0.000333 per KWH including SUT), or (2) the net of NGC – High Tension Service stated above and an NGC Credit of $0.009844 per KWH ($0.010496 per KWH including SUT), but not less than zero, for all KWH usage. Effective May 1, 2018 and for an initial term of 10 years, the Societal Benefits Charge (Rider SBC) shall include only the Demand Side Factor (Rider DSF) charge.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GT
General Service Transmission

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility of service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification OL
Outdoor Lighting Service

RESTRICTION: Mercury vapor (MV) area lighting is no longer available for replacement and shall be removed from service when existing MV area lighting fails.

APPLICABLE TO USE OF SERVICE FOR: Service Classification OL is available for outdoor flood and area lighting service operating on a standard illumination schedule of 4200 hours per year, and installed on existing wood distribution poles where secondary facilities exist. This Service is not available for the lighting of public streets and highways. This Service is also not available where, in the Company's judgment, it may be objectionable to others, or where, having been installed, it is objectionable to others.

CHARACTER OF SERVICE: Sodium vapor (SV) flood lighting, high pressure sodium (HPS) and mercury vapor (MV) area lighting for limited period (dusk to dawn) at nominal 120 volts.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings

Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	HPS Area Lighting	MV Area Lighting	SV Flood Lighting
100	121	42	Not Available	**$ 2.89**	Not Available
175	211	74	Not Available	**$ 2.89**	Not Available
70	99	35	**$11.96**	Not Available	Not Available
100	137	48	**$11.96**	Not Available	Not Available
150	176	62	Not Available	Not Available	**$14.05**
250	293	103	Not Available	Not Available	**$14.77**
400	498	174	Not Available	Not Available	**$15.15**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.053959** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

Service Classification OL
Outdoor Lighting Service

TERM OF CONTRACT: One year for each installation and thereafter on a monthly basis. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, plus 3) any additional monthly facility charges, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer. Restoration of Service to lamps which have been disconnected after the contract term has expired shall require a 5 year contract term to be initialized.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

FACILITIES:

(a) Location of Facilities: Fixtures, lamps, controls, poles, hardware, conductors, and other appurtenances necessary for Service under this Service Classification shall be owned and maintained by the Company and must be located where they can be maintained by the use of the Company's standard mechanized equipment. Should customer desire that Company relocate its outdoor lighting facilities at any time, the relocation expense shall be paid by the customer.

(b) Additional Facilities: The per Billing Month charges for poles, transformers and spans of wire furnished by the Company for Service under this Service Classification prior to February 6, 1979 shall respectively be **$0.79, $3.16** and **$0.74** until such time as there is a customer change or those facilities are no longer utilized exclusively for service under this Service Classification, or if those facilities require replacement. New or replacement facilities furnished after that date shall be provided, at the Company's option under a 5-year term of contract, based upon payment of: (1) the following per Billing Monthly charges to be added to the Flat Service Charge: 35 foot pole: **$7.22**; 40 foot pole: **$8.08** Secondary Span: **$3.65;** or (2) a single non-refundable contribution determined under Appendix A (See Tariff Part II) charges when applicable; or otherwise (3) upon payment of specific charges determined under billing work order unitized costs.

(c) Maintenance of Facilities: Maintenance of facilities furnished by the Company under this Service Classification shall be scheduled during the Company's regular business hours upon notification by the customer of the need for such service. Maintenance of facilities at times other than during the Company's regular business hours shall be performed at the expense of the customer.

SPECIAL PROVISIONS:
(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment will not be billed. The monthly Fixture Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification SVL
Sodium Vapor Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification SVL is available for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

Sodium vapor conversions of mercury vapor or incandescent street lights shall be scheduled in accordance with the Company's SVL Conversion Program, and may be limited to no more than 5% of the lamps served under this Service Classification at the end of the previous year.

CHARACTER OF SERVICE: Sodium vapor lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
50	60	21	**$ 6.98**	**$ 1.96**	**$ 0.95**
70	85	30	**$ 6.98**	**$ 1.96**	**$ 0.95**
100	121	42	**$ 6.98**	**$ 1.96**	**$ 0.95**
150	176	62	**$ 6.98**	**$ 1.96**	**$ 0.95**
250	293	103	**$ 8.25**	**$ 1.96**	**$ 0.95**
400	498	174	**$ 8.25**	**$ 1.96**	**$ 0.95**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.053959** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

Service Classification SVL
Sodium Vapor Street Lighting Service

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:

(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Contribution Fixtures: Contribution Fixtures refer to Company Fixtures for which installation the customer has paid the following Contributed Installation Cost. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company.

Contributed Installation Cost: The Contributed Installation Cost, per fixture, shall be equal to the cost shown on Tariff Part II, Appendix A – Exhibit III, for Street Light Luminaire.

(c) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the current edition of the National Electrical Code, as well as equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(d) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled fixture maintenance or replacements as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Fixture Service is provided for Company Fixtures and Contribution Fixtures only. Customer Fixtures currently being provided Limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at the stated Customer Fixture Charge plus **$1.11** per Billing Month. However, Limited Fixture Service is not available for new Customer Fixture installations.

(e) Street Light Poles: Street Light Poles are defined as poles installed for street lighting purposes which are not "standard wood distribution-type poles". These street light poles are typically used for underground distribution applications, and would include aluminum, laminated wood and fiberglass poles. Street Light Poles are installed only upon payment of a non-refundable contribution determined under Appendix A (See Tariff Part II) charges when applicable, or otherwise under fixed-price billing work order costs. Street Light Poles which have previously been installed at the Company's cost shall be billed at the monthly Street Light Pole Charge set forth in Special Provision (b), or the customer may make a payment equivalent to the current installed cost of a similar pole. Street light poles may be provided on private property roadways and associated parking areas, such as apartment building and townhouse complexes. Wood distribution-type poles typically required for street light installations served from overhead distribution facilities shall be considered as distribution poles rather than street light

Service Classification SVL
Sodium Vapor Street Lighting Service

(Continued) poles. When such poles include the mounting of street lighting fixtures provided under this Service Classification, they shall be considered as "fixture-poles" and will be installed, with their associated street lighting wire, without charge to the customer. "Span-poles", which are installed to carry wire to "fixture-poles", shall be installed with their associated wire only upon payment of a non-refundable contribution determined under Appendix A charges (see Tariff Part II) when applicable, or otherwise under billing work order cost estimates. Both fixture-poles and span-poles are installed only along public roadways, or for the extension of existing street lighting service on municipal or governmental properties.

(f) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

SPECIAL PROVISIONS:
(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment will not be billed. The monthly Fixture Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Street Light Pole Charge: Where the Company has installed, at its cost, a pole other than a wood distribution pole for a lamp fixture, a per Billing Month Pole Charge of **$9.31** shall be added to the Fixture Charge specified. Such charge shall not be applicable to a Street Light Pole which has had its installation cost paid for by the customer.

(c) Reduced Lighting Hours: This Special Provision is restricted to previously installed municipal parking lot lighting where the customer desires that energy for such lighting be conserved by having the Service inoperative for six hours per night and the customer reimburses the Company for the cost of any labor and materials required to provide such time control. The Billing Month KWH for lights under this Special Provision will be reduced based on 2010 annual burning hours. The monthly bill shall be the total of 1) the full monthly Fixture Charge plus 2) the reduced Billing Month KWH times all per KWH charges (BGS Energy and Reconciliation Charges, Transmission Charge, Distribution Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment), plus 3) a reduced lighting hours adjustment equal to the Billing Month KWH difference between the standard illumination schedule and the reduced lighting hours schedule for the light, times the per KWH Distribution Charge.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification MVL
Mercury Vapor Street Lighting Service

RESTRICTION: Service Classification MVL is in process of elimination and is withdrawn except for the installations of customers receiving Service hereunder on July 21, 1982, and only for the specific premises and class of service of such customer served hereunder on such date.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents. At the option of the Company, Service may also be provided for lighting service on streets, roads or parking areas on municipal or private property where supplied directly from the Company's facilities when such Service is contracted for by the owner or agency operating such property.

CHARACTER OF SERVICE: Mercury vapor lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All charges include Sale and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
100	121	42	**$ 4.87**	**$ 1.84**	**$ 0.94**
175	211	74	**$ 4.87**	**$ 1.84**	**$ 0.94**
250	295	103	**$ 4.87**	**$ 1.84**	**$ 0.94**
400	468	164	**$ 5.29**	**$ 1.84**	**$ 0.94**
700	803	281	**$ 6.40**	**$ 1.84**	**$ 0.94**
1000	1135	397	**$ 6.40**	**$ 1.84**	**$ 0.94**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.053959** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

Service Classification MVL
Mercury Vapor Street Lighting Service

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:

(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Contribution Fixtures: Contribution Fixtures refer to Company Fixtures for which installation the customer has paid the following Contributed Installation Cost. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company. The per Billing Month charges for Contribution Fixtures shall be discontinued only upon payment of a **$35.57** charge per fixture to cover the cost of removal.

Contributed Installation Cost:	Lamp Wattage	Lamp Wattage	Lamp Wattage
	100, 175, & 250	400	700 & 1000
For currently installed fixture:	**$141.33**	**$159.49**	**$210.97**

(c) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(d) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled fixture maintenance or replacements as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Customer Fixtures currently being provided Limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at an additional cost of **$0.92** per Billing Month.

Service Classification MVL
Mercury Vapor Street Lighting Service

(e) Street Light Poles: Street Light Poles refer to all poles other than wood distribution poles, installed, owned and maintained by the Company for street lighting service. Street Light Poles are provided only upon payment by the customer for the installation cost of such pole. Street Light Poles which have previously been installed at the Company's cost, shall be billed at the per Billing Month Street Light Pole Charge set forth in Special Provision (b), or the customer may make a **$345.22** payment to cover the cost of such previous installation.

(f) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment will not be billed. The monthly Fixture Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Street Light Pole Charge: Where the Company has installed, at its cost, a pole other than a wood distribution pole for a lamp fixture, a per Billing Month Pole Charge of **$9.31** shall be added to the Fixture Charge specified. Such charge shall not be applicable to a Street Light Pole which has had its installation cost paid for by the customer.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification ISL
Incandescent Street Lighting Service

RESTRICTION: Service Classification ISL is in process of elimination and is withdrawn except for the installations of customers currently receiving Service, and except for fire alarm and police box lamps provided under Special Provision (c). The obsolescence of this Service Classification's facilities further dictates that Service be discontinued to any installation that requires the replacement of a fixture, bracket or street light pole.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets or roads where required by city, town, county, State or other principal or public agency or by an incorporated association of local residents.

CHARACTER OF SERVICE: Incandescent lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All Charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings Lamp Wattage	Billing Month KWH *	Company Fixture	Customer Fixture
105	37	**$ 2.06**	**$ 0.94**
205	72	**$ 2.06**	**$ 0.94**
327	114	**$ 2.06**	**$ 0.94**
448	157	**$ 2.06**	**$ 0.94**
690	242	**$ 2.06**	**$ 0.94**
860	301	**$ 2.06**	**$ 0.94**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.053959** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

Service Classification ISL
Incandescent Street Lighting Service

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:
(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service, installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(c) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled lamp and control switch replacement as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Customer fixtures currently being provided limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at the stated Customer Fixture Charge plus **$1.11** per Billing Month.

(d) Street Light Poles: Street Light Poles refer to all poles, other than wood distribution poles, installed, owned and maintained by the Company for street lighting service. Replacement of Street Light Poles shall be provided only upon payment by the customer for the current installation cost of such replacement poles except when occasioned and such cost recoverable by a third party.

(e) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

Service Classification ISL
Incandescent Street Lighting Service

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment will not be billed. The monthly Fixture Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Fire Alarm and Police Box Lamp Charge: 25 watt lamps serviced by the Company and served from existing secondary facilities will be billed a monthly Fixture Charge of **$1.22** and **$0.35** for lamps with individual time controls operated on a standard illumination schedule, and lamps operated 24 hours per day, respectively. Lamps with individual time controls operated on a standard illumination schedule will have a Billing Month KWH of 9 KWH. Lamps operated 24 hours per day will have a Billing Month KWH of 18 KWH. All per KWH charges (BGS Energy and Reconciliation Charges, Transmission Charge, Distribution Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Storm Recovery Charge, Zero Emission Certificate Recovery Charge and Tax Act Adjustment) will be billed based on the applicable lamp's Billing Month KWH.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification LED
LED Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification LED is available for installation of 12 or more LED (light emitting diode) fixtures per request for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities along public streets and roadways, or for the extension of existing street lighting service on municipal or governmental properties (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents

CHARACTER OF SERVICE: LED lighting service is for limited period (dusk to dawn). Standard Service shall be supplied from existing lines, using the Company's standard fixtures and other appurtenances on existing wood distribution poles unrestricted as to their use by Company for purposes other than street lighting, on which existing wood distribution poles the required secondary voltage is present. The rating of the fixture in lumens is for identification and is intended to approximate the manufacturer's standard rating.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

COMPANY FIXTURES: Company Fixtures refer to fixtures installed by the Company in accordance with Standard Service and its specifications at its expense. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

COMPANY FIXTURE

Lamp Wattage	Type	Lumens	Billing Month KWH*	Company Fixture
30	Cobra Head	2400	11	**$ 7.14**
50	Cobra Head	4000	18	**$ 7.09**
90	Cobra Head	7000	32	**$ 7.67**
130	Cobra Head	11500	46	**$ 8.73**
260	Cobra Head	24000	91	**$ 11.09**
50	Acorn	2500	18	**$ 18.18**
90	Acorn	5000	32	**$ 17.56**
50	Colonial	2500	18	**$ 10.21**
90	Colonial	5000	32	**$ 12.27**

CONTRIBUTION FIXTURES: Contribution Fixtures refer to fixtures installed by the Company in accordance with Standard Service and its specifications for which installation the customer has paid the Contributed Installation Cost. The Company provides two contribution levels for the Contributed Installation Cost, at the Customer's option, that have different corresponding monthly charges. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company. Contribution Fixture service does not include or provide for the replacement of the fixture at failure or end of life. A contribution payment to JCP&L shall not give the customer any interest in the facilities, the ownership being vested exclusively in JCP&L.

Contributed Installation Cost: The Contributed Installation Cost, per fixture, shall be equal to the cost shown on Tariff Part II, Appendix A – Exhibit III, for Street Light Luminaire, which costs are subject to gross-up for applicable income taxes.

Service Classification LED
LED Street Lighting Service

CONTRIBUTION FIXTURE (a)

Fixture Wattage	Type	Lumens	Billing Month KWH*	Fixture Charge	Contribution Fixture (a)
30	Cobra Head	2400	11	$ 2.92	$ 358.38
50	Cobra Head	4000	18	$ 2.92	$ 354.88
90	Cobra Head	7000	32	$ 2.92	$ 403.55
130	Cobra Head	11500	46	$ 2.92	$ 492.97
260	Cobra Head	24000	91	$ 2.92	$ 694.22
50	Acorn	2500	18	$ 2.92	$1,295.80
90	Acorn	5000	32	$ 2.92	$1,243.30
50	Colonial	2500	18	$ 2.92	$ 619.38
90	Colonial	5000	32	$ 2.92	$ 793.88

CONTRIBUTION FIXTURE (b)

Fixture Wattage	Type	Lumens	Billing Month KWH*	Fixture Charge	Contribution Fixture (b)
30	Cobra Head	2400	11	$ 4.68	$ 209.20
50	Cobra Head	4000	18	$ 4.68	$ 205.70
90	Cobra Head	7000	32	$ 4.68	$ 254.37
130	Cobra Head	11500	46	$ 4.68	$ 343.79
260	Cobra Head	24000	91	$ 4.68	$ 545.04
50	Acorn	2500	18	$ 4.68	$1,146.62
90	Acorn	5000	32	$ 4.68	$1,094.12
50	Colonial	2500	18	$ 4.68	$ 470.20
90	Colonial	5000	32	$ 4.68	$ 644.70

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the wattage of the fixture, times the fixture's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.053959** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

Service Classification LED
LED Street Lighting Service

TERM OF CONTRACT: Fifteen years for each fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than fifteen years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the fixture's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the fixture's Billing Month KWH, times the remaining months of the contract term.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

MISCELLANEOUS:
Non-Standard Installations: Where the installation of additional facilities, including, but not limited to: poles, wire, transformers, and brackets, is required to provide service to a fixture, Customers shall be responsible for payment of a non-refundable Contribution in Aid of Construction determined under Appendix A charges (see Tariff Part II) when applicable, or otherwise under billing work order costs estimates, which costs are subject to gross-up for applicable income taxes.
(a) Changes in Fixture Wattage, Type or Location: Customers will be required to pay the cost for relocation, changes in fixture wattage, fixture type, color (Kelvin temperature) and conversion from an LED light source to another when the age of the fixture is less than 15 years. These costs will include removal cost less salvage and installation cost of the fixture. Except for relocations, the cost will also include the remaining net book value of the existing fixture and, in the case of Contribution Fixtures, payment of the Contributed Installation Cost.

i) Installation of a new fixture at the same location of the removal of an existing fixture within 12 months will be considered a replacement of the existing fixture and will be subject to charges including the removal cost less salvage for the fixture removed, the installation cost of the new fixture and, if applicable, any Contribution Installation Cost.

ii) LED conversions of sodium vapor, mercury vapor or incandescent fixtures shall be scheduled at the Company's reasonable discretion. JCP&L reserves the right to limit the number of fixtures conversions in any year to no more than 5% of the total fixtures served at the end of the previous year.

(b) Traffic Control: The Municipality will be responsible for providing and paying the costs of police assistance when deemed necessary by local authorities. The Company will provide basic traffic control (flaggers) at no cost to the Municipality. When traffic control (flagging) labor hours exceed construction labor hours (considered non-basic traffic control) the Municipality will be responsible for paying the differential in costs between basic and non-basic traffic control. The Municipality will also be responsible for all fees associated with required permitting.
(c) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the fixture will be zero. Only the monthly Fixture Charge and a seasonal Distribution Charge will be billed (i.e., Basic Generation Service and other Delivery Service charges will not be billed) during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.
(d) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)

Effective June 1, 2015, Rider BGS-FP (Basic Generation Service – Fixed Pricing) is renamed Rider BGS-RSCP to comply with the BPU Order dated November 24, 2014 (Docket No. ER14040370).

AVAILABILITY: Rider BGS-RSCP is available to and provides Basic Generation Service (default service) charges applicable to all KWH usage for Full Service Customers taking service at secondary voltages under Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED, except for GS and GST customers that have a peak load share of 500 KW or greater as of November 1, 2018. Rider BGS-RSCP-eligible GS and GST customers may elect to take default service under Rider BGS-CIEP no later than the second business day in January of each year. Such election will be effective June 1 of that year and Rider BGS-CIEP will remain the customer's default service for the entire 12-month period from June 1 through May 31 of the following year. BGS-RSCP-eligible customers who have elected to take default service under BGS-CIEP may return to BGS-RSCP by notifying the Company no later than the second business day in January of each year. Such notification to return to BGS-RSCP will become effective June 1 of that year.

RATE PER BILLING MONTH: (For service rendered effective June 1, 2019 through May 31, 2020)
1) BGS Energy Charge per KWH: (All charges include Sales and Use Tax as provided in Rider SUT.)

Service Classification	June through September	October through May
RS - first 600 KWH	**$0.071616**	
- all KWH over 600	**$0.080841**	
- all KWH		**$0.080232**
(Excludes off-peak and controlled water heating special provisions)		
RT - all on-peak KWH	**$0.136930**	**$0.136930**
- all off-peak KWH	**$0.049909**	**$0.053700**
RGT - all on-peak KWH	**$0.136930**	
- all off-peak KWH	**$0.049909**	
- all KWH		**$0.080232**
RS and GS Water Heating – all KWH	**$0.086075**	**$0.083786**
(For separately metered off-peak and controlled water heating usage under applicable special provisions)		
GS - all KWH	**$0.080390**	**$0.080390**
(Excludes off-peak and controlled water heating special provisions)		
GST - all on-peak KWH	**$0.133218**	**$0.118373**
- all off-peak KWH	**$0.050620**	**$0.053700**
OL, SVL, MVL, ISL, LED - all KWH	**$0.055592**	**$0.057092**

BGS Energy Charges above reflect costs for energy, generation capacity, ancillary services and related cost.

Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED. Effective September 1, 2019, a RMR surcharge of **$0.000000** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective **September 1, 2019**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

TRAILCO-TEC surcharge of **$0.000234** per KWH
Delmarva-TEC surcharge of **$0.000001** per KWH
ACE-TEC surcharge of **$0.000069** per KWH
PEPCO-TEC surcharge of **$0.000014** per KWH
PPL-TEC surcharge of **$0.000729** per KWH
BG&E-TEC surcharge of **$0.000016** per KWH
PECO-TEC surcharge of **$0.000065** per KWH

Effective **February 1, 2020**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

PSEG-TEC surcharge of **$0.002588** per KWH
VEPCO-TEC surcharge of **$0.000181** per KWH
PATH-TEC surcharge of (**$0.000003)** per KWH
AEP-East-TEC surcharge of **$0.000046** per KWH
MAIT-TEC surcharge of **$0.000096** per KWH
EL05-121-TEC surcharge of **$0.000228** per KWH

3) BGS Reconciliation Charge per KWH: $0.001367 (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-ups.

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

AVAILABILITY: Rider BGS-CIEP is available to and provides Basic Generation Service (default service) charges applicable to all Full Service Customers taking service at primary and transmission voltages under Service Classifications GP and GT and any Full Service Customers taking service at secondary voltages under Service Classifications GS and GST that have a peak load share of 500 KW or greater as of November 1, 2018, or that have elected to take BGS-CIEP service no later than the second business day in January of each year. All BGS-CIEP customers remain subject to this Rider for the entire 12-month period from June 1 of any given year through May 31 of the following year.

RATE PER BILLING MONTH:
(For service rendered effective June 1, 2019 through May 31, 2020)

1) BGS Energy Charge per KWH: The sum of actual real-time PJM load weighted average Residual Metered Load Aggregate Locational Marginal Price for JCP&L Transmission Zone and ancillary services of **$0.00600** per KWH, times the Losses Multiplier provided below, times 1.06625 multiplier for Sales and Use Tax as provided in Rider SUT.

Losses Multiplier:	GT – High Tension Service	1.005
	GT	1.027
	GP	1.047
	GST	1.103
	GS	1.103

2) BGS Capacity Charge per KW of Generation Obligation: $0.24601 per KW-day times BGS-CIEP customer's share of the capacity peak load assigned to the JCP&L Transmission Zone by the PJM Interconnection, L.L.C., as adjusted by PJM assigned capacity related factors, times 1.06625 multiplier for Sales and Use Tax as provided in Rider SUT.

3) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications GS, GST, GP and GT. Effective September 1, 2019, a RMR surcharge will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

GT – High Tension Service	**$0.000000**
GT	**$0.000000**
GP	**$0.000000**
GS and GST	**$0.000000**

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

3) BGS Transmission Charge per KWH: (Continued)

Effective **September 1, 2019**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	TRAILCO-TEC	Delmarva-TEC	ACE-TEC
GS and GST	**$0.000234**	**$0.000001**	**$0.000069**
GP	**$0.000151**	**$0.000000**	**$0.000046**
GT	**$0.000133**	**$0.000000**	**$0.000041**
GT – High Tension Service	**$0.000031**	**$0.000000**	**$0.000010**
	PEPCO-TEC	PPL-TEC	BG&E-TEC
GS and GST	**$0.000014**	**$0.000729**	**$0.000016**
GP	**$0.000010**	**$0.000474**	**$0.000011**
GT	**$0.000009**	**$0.000419**	**$0.000010**
GT – High Tension Service	**$0.000002**	**$0.000098**	**$0.000002**
	PECO-TEC		
GS and GST	**$0.000065**		
GP	**$0.000043**		
GT	**$0.000037**		
GT – High Tension Service	**$0.000009**		

Effective **February 1, 2020**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	PSEG-TEC	VEPCO-TEC	PATH-TEC
GS and GST	**$0.002588**	**$0.000181**	**($0.000003)**
GP	**$0.001691**	**$0.000118**	**($0.000002)**
GT	**$0.001482**	**$0.000103**	**($0.000002)**
GT – High Tension Service	**$0.000341**	**$0.000023**	**($0.000000)**

	AEP-East-TEC	MAIT-TEC	EL05-121-TEC
GS and GST	**$0.000046**	**$0.000096**	**$0.000228**
GP	**$0.000030**	**$0.000063**	**$0.000149**
GT	**$0.000027**	**$0.000054**	**$0.000131**
GT – High Tension Service	**$0.000006**	**$0.000013**	**$0.000030**

4) BGS Reconciliation Charge per KWH: ($0.002392) (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-ups.

Rider CIEP – Standby Fee
Commercial Industrial Energy Pricing Standby Fee
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

Effective June 1, 2007, Rider DSSAC (Default Supply Service Availability Charge) is renamed Rider CIEP – Standby Fee to comply with the BPU Order dated December 22, 2006 (Docket No. EO06020119).

APPLICABILITY: Rider CIEP – Standby Fee provides a charge applicable to all KWH usage of all Full Service Customers or Delivery Service Customers taking service under Service Classifications GP and GT and any Full Service Customer or Delivery Service Customer taking service under Service Classifications GS and GST that has a peak load share of 500 KW or greater as of November 1, 2018, or that has elected to take Basic Generation Service-Commercial Industrial Energy Pricing under Rider-CIEP no later than the second business day in January of each year. This charge is applicable for service rendered from June 1, 2019 through May 31, 2020 to recover costs associated with administrating and maintaining the availability of the hourly-priced default Basic Generation Service for these customers.

CIEP – Standby Fee per KWH: $0.000150

(**$0.000160** including Sales and Use Tax as provided in Rider SUT)

Rider NGC
Non-utility Generation Charge

APPLICABILITY: Rider NGC provides a non-utility generation charge ("NGC") applicable to all KWH usage of any Full Service Customer or Delivery Service Customer. Effective September 1, 2004, Rider MTC ("Market Transition Charge") is renamed Rider NGC to comply with the BPU Final Order dated May 17, 2004 (Docket Nos. ER02080506, etc.) that "the MTC shall be discontinued and renamed the NGC" for customer billing purposes.

Effective August 1, 2003, the Company recovers through the MTC charge, the MTC deferred balance which includes: (1) BPU-approved costs incurred during the transition to a competitive retail market and under-recovered during the period from August 1, 1999 through July 31, 2003; and (2) all BPU-approved costs associated with committed supply energy, capacity and ancillary services, net of all revenues from the sale of the committed supply in the wholesale market (Docket Nos. EX01110754 and EX01050303, etc.) Carrying cost shall be computed on a monthly basis at the applicable BPU-approved interest rate on the average net-of-tax over or under-recovered balance of the MTC, compounded annually.

Effective August 1, 2003, the composite MTC Factor shall be $0.011013 per KWH (excluding SUT), which includes the interim recovery of MTC deferred balance as of July 31, 2003, until the BPU's decision on the securitization of the MTC deferred balance.

Effective June 1, 2005, the composite MTC Factor shall be reduced to $0.010614 per KWH (excluding SUT), which includes the anticipation of the savings to be realized from the securitization of a portion of the MTC deferred balance as of July 31, 2003 ("Deferred BGS Transition Costs") pending the BPU approval. By Order dated June 8, 2006, the BPU approved the securitization of Deferred BGS Transition Costs.

Effective December 6, 2006, the composite MTC/NGC Factor shall be $0.015492 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.004878 per KWH.

Effective March 1, 2011, the composite MTC/NGC Factor shall be $0.007687 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.007805 per KWH.

Effective March 1, 2012, the composite MTC/NGC Factor shall be $0.002839 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.004848 per KWH.

Effective February 2, 2015, the composite MTC/NGC Factor shall be $0.003750 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.000911 per KWH.

Effective September 1, 2016, the composite MTC/NGC Factor shall be $0.005012 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.001262 per KWH. By Board Order dated May 31, 2017 (Docket No. ER16101046), the Board approved no change to this Factor for the 2015 NGC Filing.

Effective June 10, 2017, the composite MTC/NGC Factor shall be $0.001527 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.001548 per KWH and the OC-TBC and OC-MTC-Tax associated with the securitization of Oyster Creek at zero rate. By Board Order dated September 17, 2018 (Docket No. ER17030306), the Board approved no change to this Factor for the 2016 NGC Filing.

Effective November 1, 2018, the composite MTC/NGC Factor shall be $0.000451 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.001076 per KWH. By Board Order dated June 12, 2019 (Docket No. ER18090977), the Board approved no change to this Factor for the 2017 NGC Filing.

Effective January 1, 2020, the composite MTC/NGC Factor shall be $0.000105 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.000346 per KWH.

Rider NGC
Non-utility Generation Charge

For billing purposes, the composite MTC/NGC Factor of $0.000105 per KWH, which includes the revised DB-TBC and DB-MTC-Tax associated with the securitization of Deferred BGS Transition Costs, as detailed below, shall be applied to all KWH usage of any Full Service Customer or Delivery Service Customer as follows:

Voltage Adjusted MTC Charges per KWH (renamed NGC Charges per KWH)		Including SUT
Secondary Voltages	**$0.000107**	**$0.000114**
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)		
Primary Voltages	**$0.000102**	**$0.000109**
(Applicable to Service Classification GP)		
Transmission Voltages	**$0.000100**	**$0.000107**
High Tension Service (230 KV)	**$0.000098**	**$0.000104**
(Applicable to Service Classification GT)		

Rider NGC
Non-utility Generation Charge

Securitization of Oyster Creek

On February 6, 2002, the BPU approved and issued a Bondable Stranded Costs Rate Order ("Oyster Creek Rate Order") (Docket No. EF99080615) authorizing the issuance and sale of up to $320 million aggregate principal amount of transition bonds to recover certain bondable stranded costs related to the investment in the Oyster Creek Nuclear Generating Station, the imposition of a non-bypassable Transition Bond Charge ("OC-TBC") for the recovery of such costs and the related Market Transition Charge-Tax ("OC-MTC-Tax). The bondable stranded costs are defined in the Oyster Creek Rate Order and include: (1) the capital reduction costs, (2) the upfront transaction costs and (3) the ongoing transition bond costs.

Effective June 11, 2002, the MTC included an OC-TBC of $0.001921 per KWH and an OC-MTC-Tax of $0.000505 per KWH (or $0.002036 per KWH and $0.000535 per KWH including SUT, respectively). The OC-TBC and OC-MTC-Tax are governed by the provisions of the Oyster Creek Rate Order and are subject to periodic true-ups, at least annually but not more frequently than quarterly, except monthly true-ups are permitted in the last year before the scheduled maturity of the transition bonds and continuing until final maturity, as provided in the Oyster Creek Rate Order.

On February 28, 2017, a true-up letter was filed with the BPU in accordance with the provisions in the Oyster Creek Rate Order. Effective May 1, 2017 through May 6, 2017, the OC-TBC and OC-MTC-Tax shall be $0.001198 per KWH and $0.000739 per KWH, respectively (or $0.001280 per KWH and $0.000790 per KWH including SUT, respectively). Effective May 7, 2017, the OC-TBC and OC-MTC-Tax shall be at zero.

Securitization of Deferred BGS Transition Costs

By Order dated June 8, 2006, the BPU approved and issued a Bondable Stranded Costs Rate Order ("Deferred BGS Transition Costs Rate Order") (Docket No. ER03020133) authorizing the issuance and sale of $182.4 million aggregate principal amount of transition bonds to recover the Company's net of tax deferred basic generation service transition costs incurred during the transition period from August 1, 1999 through July 31, 2003, the imposition of a non-bypassable Transition Bond Charge ("DB-TBC") for the recovery of such costs and the related Market Transition Charge-Tax ("DB-MTC-Tax"). The bondable stranded costs are defined in the Deferred BGS Transition Costs Rate Order and include: (1) the upfront transaction costs and (2) the ongoing transition bond costs.

Effective August 10, 2006, the NGC included a DB-TBC of $0.001230 per KWH and a DB-MTC-Tax of $0.000572 per KWH (or $0.001316 per KWH and $0.000612 per KWH including SUT, respectively). The DB-TBC and DB-MTC-Tax are governed by the provisions of the Deferred BGS Transition Costs Rate Order and are subject to periodic true-ups, at least annually but not more frequently than quarterly, and continuing until final maturity, as provided in the Deferred BGS Transition Costs Rate Order.

On March 22, 2019, a true-up letter was filed with the BPU in accordance with the provisions in the Deferred BGS Transition Costs Rate Order. Effective June 1, 2019, the DB-TBC and DB-MTC-Tax shall be revised to $0.000783 per KWH and $0.000296 per KWH, respectively (or $0.000835 per KWH and $0.000316 per KWH including SUT, respectively).

Rider NGC
Non-utility Generation Charge

St. Lawrence Hydroelectric Power

At the November 9, 2004 agenda meeting, the BPU verbally approved, among other things, the Public Power Association of New Jersey ("PPANJ") as Bargaining Agent for the State of New Jersey to renegotiate with the New York Power Authority ("NYPA"), on the allocation of service tariff capacity and associated energy produced at the St. Lawrence/FDR project (In the Matter of the Allocation of St. Lawrence Hydroelectric Power to the State of New Jersey Docket No. EO04101124).

On December 21, 2004, the PPANJ filed with the BPU the following documents associated with the St. Lawrence Hydroelectric Power matter: 1) Agreement for Electric Service Investor Owned Utility Between the PPANJ and JCP&L, PSE&G, Rockland Electric and Atlantic City Electric Company; 2) Agreement Governing Administration of NYPA Power ("Administration Agreement"); and 3) PPANJ for State of New Jersey Service Tariff Capacity and Associated Energy.

Pursuant to the Administration Agreement, the Company, as Nominal Recipient of the Investor-Owned Electric Utilities' share of St. Lawrence/FDR project, is responsible to deliver and distribute the capacity and associated energy as Basic Generation Service to residential customers as designated by the BPU. In addition, the Company is responsible to distribute to each of the Investor-Owned Electric Utilities the Net Economic Benefits calculated according to the Rate Schedule attached to the Administration Agreement. Each of the Investor-Owned Electric Utilities shall allocate the Net Economic Benefits distributed to it to its residential customers through the Investor-Owned Electric Utility's applicable clause through which it recovers non-utility generation costs, or other appropriate rate mechanism if no such clause exists, in a manner that ensures that such benefits flow exclusively to residential customers.

The Company, in its role as Nominal Recipient of the St. Lawrence/FDR project, advises the Investor-Owned Electric Utilities of their respective allocation of the Net Economic Benefits for the period started January 1, 2018 through December 31, 2018. JCP&L's share of the Net Economic Benefits totaled $297,502.44.

Effective June 1, 2019 through May 31, 2020, a St. Lawrence Hydroelectric Power **credit** of **$0.000032** per KWH (**$0.000034** per KWH including SUT) will be combined with the Secondary Voltages Adjusted NGC Charge applicable to Service Classifications RS, RT and RGT. Such combined NGC Charge shall be applied to all KWH usage of any Full Service or Delivery Service residential customers.

Rider SBC
Societal Benefits Charge

APPLICABILITY: Rider SBC provides a charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer. The charges that may be included in calculating the SBC include nuclear plant decommissioning costs (Rider NDC), demand side management costs (Rider DSF), manufactured gas plant remediation costs (Rider RAC), uncollectible costs (Rider UNC), and universal service fund costs (Rider USF), in accordance with the New Jersey Electric Discount and Energy Competition Act. The current SBC includes the following charges per KWH:

		Including SUT
Rider DSF	**$0.003457**	**$0.003686**
Rider NDC	**$0.000000**	**$0.000000**
Rider RAC	**$0.000811**	**$0.000865**
Rider UNC	**$0.000352**	**$0.000375**
Rider USF	**$0.001957**	**$0.002087**

Carrying costs on unamortized balances of demand side management costs, nuclear decommissioning costs, manufactured gas plant remediation costs, uncollectible costs and universal service fund costs shall be calculated in accordance with the terms of Rider DSF, Rider NDC, Rider RAC, Rider UNC and Rider USF, respectively.

Effective November 1, 2019, the SBC shall be applied to all KWH usage for billing purposes as follows:

		Including SUT
Total SBC:	**$0.006577**	**$0.007013**

Beginning January 1, 2011, with the exception of universal service fund costs component, all over- and under-recoveries of individual SBC components are to be applied to under- or over-recoveries of other SBC components as of each December 31.

Rider DSF
Demand Side Factor

APPLICABILITY: Rider DSF provides a charge for costs associated with New Jersey Clean Energy Program. The DSF is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

DSF = $0.003457 per KWH ($0.003686 per KWH including SUT)

Demand Side Factor costs include carrying costs on any unamortized balances of such costs at the applicable interest approved by the BPU in its Final Order dated May 17, 2004 (Dockets Nos. ER02080506, et al.), such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

Rider NDC
Nuclear Decommissioning Costs

APPLICABILITY: Rider NDC provides a charge for Nuclear Decommissioning costs. The NDC is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

NDC = $0.000000 per KWH ($0.000000 per KWH including SUT)

Nuclear Decommissioning costs include carrying costs on any unamortized balances of such costs at the applicable interest rate approved by the BPU in its Final Order dated May 17, 2004 (Docket Nos. ER02080506, et al.). Such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Rider RAC
Remediation Adjustment Clause

APPLICABILITY: Rider RAC determines a Remediation Adjustment in accordance with the formula set forth below. The factor is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

The calculated RAC rate shall be prepared by the Company and filed with the BPU annually by the end of December with a requested effective date of June 1 of the subsequent year. Rider RAC provides for the recovery of manufactured gas plant remediation costs (net of insurance and other recoveries) over rolling seven year periods, including carrying costs on the unamortized balance. Carrying cost is calculated on a monthly basis at an interest rate equal to the rate on seven-year constant maturity Treasuries, as shown in the Federal Reserve Statistical Release on or closest to January 1 of each year, plus sixty basis points, compounded annually as of January 1 of each year.

CALCULATION OF THE REMEDIATION ADJUSTMENT CLAUSE FACTOR:

1) By using the following formula:

RAC = Recoverable Cost / Sales

2) Where the terms are defined as follows:

RAC = The Remediation Adjustment Clause factor in cents per KWH to be applied to all applicable retail KWH sales.

Recoverable Cost = Manufactured Gas Plant remediation expenses (net of insurance and other recoveries) amortized over rolling seven year periods. The cost includes carrying costs on any unamortized balance of remediation costs, net of associated deferred tax balance, at an annual interest rate stated above.

Sales = The Company's forecasted retail KWH sales.

3) Effective November 1, 2019, the RAC computation is as follows ($ Millions):

RAC = $16.434 / 20,263,615 MWH = $0.000811 per KWH
($0.000865 per KWH including SUT)

Rider UNC
Uncollectible Accounts Charge

APPLICABILITY: Rider UNC provides a charge for costs associated with uncollectible accounts recorded in FERC account 904 (Uncollectible Accounts). The UNC is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

UNC = $0.000352 per KWH ($0.000375 per KWH including SUT)

Uncollectible costs include carrying costs on any unamortized balances of such costs at the applicable interest rate approved by the BPU in its Final Order dated May 17, 2004 (Docket Nos. ER02080506, et al.). Such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

Rider USF
Universal Service Fund Costs Recovery

APPLICABILITY: Rider USF provides a charge for costs associated with the state-mandated Universal Service Fund ("USF") to assist certain customers as defined by the BPU. The USF is included in the Societal Benefits Charge and is applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

Effective October 1, 2019, the USF provided below consists of an USF rate of $0.001249 per KWH and a Lifeline rate of $0.000708 per KWH ($0.001332 per KWH and $0.000755 per KWH including SUT, respectively), pursuant to the BPU Order dated September 27, 2019 (Docket No. ER19060736).

USF = $0.001957 per KWH ($0.002087 per KWH including SUT)

Universal Service Fund costs shall accrue interest on any over or under recovered balances of such costs at the interest rate based on a two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus sixty basis points, but shall not exceed the Company's overall rate of return as approved by the BPU. Such interest rate shall be reset each month. The interest calculation shall be based on the net of tax beginning and end average monthly balance, consistent with the methodology in the Board's Final Order dated May 17, 2004 (Docket No. ER02080506 et al.), accrue monthly with an annual roll-in at the end of each reconciliation period.

Rider QFS
Cogeneration and Small Power Production Service

AVAILABILITY: Rider QFS specifies the conditions under which the Company will purchase electricity from a "Qualifying Facility" ("QF") under Section 210 of the Public Utilities Regulatory Policies Act of 1978. Rider QFS is available to customers taking service under Service Classifications GS, GST, GP and GT. QF installations must conform to, and are responsible for all costs associated with, the Company's General Interconnect Requirements for Customer's Generation, according to any applicable installation specifications. (See Part II, Section 10)

QF INSTALLATIONS WITH MORE THAN 1000 KW GENERATING CAPACITY

Such installations shall negotiate with the Company for specific contract arrangements to determine the price, term and conditions to delivered energy and capacity, where applicable; provided however, that in no event shall payments to the QF installation under this tariff exceed the revenues the Company receives from PJM (or its successor), net of PJM penalties and charges. Such contracts are subject to BPU approval.

QF INSTALLATIONS WITH 1000 KW OR LESS GENERATING CAPACITY

Service Charge: $40.00 monthly

Energy Payment: Based on actual real-time PJM load weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) for the JCP&L Transmission Zone at the time when the QF installation delivers energy to the Company.

Capacity Payment: Deliveries from a QF installation that qualify as a PJM Capacity Resource may receive capacity payments when the installed capacity of the QF installation exceeds 100 kW and meets the reliability criteria set forth in PJM Manual 18 (See www.pjm.com), as it may change from time to time. The Capacity Payment, if and as applicable, will be equal to the capacity revenues that the Company receives from PJM for selling such capacity into the Reliability Pricing Model (RPM) capacity auction prior to delivery, adjusted for all other PJM penalties and charges assessed to the Company by PJM arising from, among other things, non-performance or unavailability of the QF installation. QF installations requesting capacity payments must execute an agreement with the Company authorizing the Company to offer such capacity into the PJM market, including terms and conditions of such sale, and including any required security. Any losses experienced by the Company resulting from a QF installation’s failure to perform shall be recovered under its Non-utility Generation Charge.

Energy Payment and Capacity Payment, if any, net of Service Charge, shall be determined monthly on an after-the-fact basis, and made within 90 days of the QF meter reading date.

METERING COSTS: QF customers shall pay all metering equipment and related costs as required by the Company and/or by PJM.

INTERCONNECTION COSTS: QF customers shall pay interconnection costs (see Part II, Section 4.05) and any line extension costs required to interconnect the QF to the Company’s facilities.

Rider QFS
Cogeneration and Small Power Production Service

LIMITATION ON ENERGY PURCHASES: The Company may refuse to purchase energy from a QF when:

(a) The Company's distribution or transmission circuits are loaded to capacity and further energy would cause an overload. Such refusal to purchase may occur on an instantaneous basis.

(b) An emergency occurs on that part of the Company's system interconnected with the QF such that there would be no means of delivering the energy to the remainder of the Company's system. Such refusal to purchase may also occur on an instantaneous basis.

(c) Customer has failed to provide documentation of QF certification with F.E.R.C. as required by the Company.

(d) Customer has an account arrearage.

Rider STB
Standby Service
(Applicable to Service Classifications GS, GST, GP and GT)

AVAILABILITY: Rider STB specifies the conditions under which customers with qualifying cogeneration or small power production facilities may obtain Standby Service under this Rider when such facilities are used to meet the customer's load requirements. The terms of this Rider shall not be available in any month, however, when the customer's Generation Availability (GA) for the current month does not exceed 50%.

STANDBY DEMAND CHARGE: The terms of this Rider: (1) modify the Determination of Demand and waive the Minimum Demand Charge of the applicable service classification; and (2) impose a Standby Demand Charge determined in accordance with the following calculations and definitions:

SDC=>[(DR*BD)+(SR*<MM or AG)] or [SR*CD]

Which means that the Standby Demand Charge is equal to the greater of:
(1) DR times BD, plus SR times lesser of MM or AG; or
(2) SR times CD

DEFINITIONS:

BD = Billing Demand KW
= >[MM - AG] or [0]
Which means that the Billing Demand is equal to MM - AG, but not less than zero

MM = Maximum Monthly facility on-peak KW load
Which is the maximum coincident 15-minute on-peak load supplied by the Customer's generation plus (or minus) the load delivered by (or furnished to) the Company.

AG = Annual Average Generation on-peak
= Current and preceding eleven months average of [on-peak KWH produced / (260 hours - SM)]
Which means taking the average of each monthly on-peak Average Generation from the current and preceding eleven months. Average Generation is calculated by taking the monthly on-peak KWH produced / (260 hours – SM)

DR = Demand Rate per KW of applicable service classification

Issued: **Effective:**

Filed pursuant to Order of Board of Public Utilities
Docket No. dated

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Rider STB
Standby Service
(Applicable to Service Classifications GS, GST, GP and GT)

SR = Standby Rate per KW (including SUT)
= **$4.25** for Service Classifications GS & GST
= **$2.55** for Service Classifications GP
= **$1.22** for Service Classifications GT

CR = Capacity Rating of generation facility

CD = Contract Demand
= <[CR] or [>(estimated MM) or (>MM most recent 12 months)]
Which means that the Contract Demand is equal to the lesser of:
(1) CR; or
(2) the greater of: (a) estimated MM; or (b) highest MM of most recent 12 months

GA = Generation Availability
= AG / CD

SM = Scheduled maintenance hours
Applicable only for customers receiving service under this rider as of February 25, 1993. The number of such hours may be reduced up to the amount of mutually agreed upon scheduled maintenance hours, but are not to exceed the amount actually incurred. A maximum of two 2-week periods may be allowed per year during the billing months of April, May, June, October, November or December and must be scheduled 6-months in advance. Each maintenance period may occur only during a single billing period.

260 hours = Average monthly on-peak hours
= 52 weeks x 5 days x 12 on-peak hours ÷12 months

Rider CEP
Consumer Electronics Protection Service

RESTRICTION: This Rider is closed to new enrollment as of March 3, 1999.

AVAILABILITY: Rider CEP had been available for customers which desire that the Company provide protection from power fluctuations, surges and other power disturbances. Service under this Rider is restricted to service entrance and equipment compatibility.

A single meter socket surge suppression device is necessary on the service entrance supplying power to the premises to protect internal wiring against major power line spikes and surges. Electrical receptacle outlet surge suppressors are available for receptacles within the customer's premise. Such receptacle outlet suppressors provide protection against surges to more sensitive electronics, and are only available when a meter socket surge suppression device is installed. Uninterruptible power supply units are available for use with individual electronic equipment.

MONTHLY CHARGES:	Including SUT	Excluding SUT
Meter socket surge suppression device - single phase:	**$2.93**	**$2.75**
Meter socket surge suppression device - three phase:	**$5.33**	**$5.00**
Electrical receptacle outlet surge suppressor - 2 outlet:	**$0.64**	**$0.60**
Electrical receptacle outlet surge suppressor - 4 outlet:	**$0.80**	**$0.75**
Uninterruptible power supply unit - 0.75 KVA:	**$21.33**	**$20.00**
Uninterruptible power supply unit - 1.00 KVA:	**$26.66**	**$25.00**
Uninterruptible power supply unit - 1.50 KVA:	**$31.99**	**$30.00**

TERM OF CONTRACT:
A one-year term of contract is required, renewable thereafter on a month-to-month basis.

TERMS OF PAYMENT:
Charges applicable under this Rider will be rendered on the customer's bill for electric service. Such bills are due when rendered and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter may become subject to a late payment charge as described in Section 3.19, Part II.

Rider CEP
Consumer Electronics Protection Service

TERMS AND CONDITIONS:

1) The Company will install and remove the meter socket surge suppressor device and deliver the electrical receptacle outlet surge suppressors and/or Uninterruptible power supply equipment to the customer.

2) Customers utilizing CEP service provided under this Rider shall contact the Company in order to arrange the return of such equipment to the Company, upon termination of this Service, in the manner specified by the Company. Customers failing to arrange to return such equipment to the Company, shall be required to pay a charge equivalent to the Company's current replacement cost for such equipment.

3) The Company shall not be liable for any damage or injury arising from the improper use of equipment supplied under this Rider or for any costs or damages attributable to the loss of the customer's business, production or facilities resulting from the failure of such equipment.

4) The Company will provide the applicable manufacturer's warranty associated with the meter socket surge suppressor device and/or electrical receptacle outlet surge suppressor.

5) Disconnection and subsequent reconnection of Consumer Electronics Protection Service at the same location shall be unavailable as of March 3, 1999. However, if a customer transfers service from one location to another location within the Company's service areas, the customer may transfer the CEP service to the new location.

Rider CBT
Corporation Business Tax

APPLICABILITY: In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), provision for the New Jersey Corporation Business Tax (CBT) as it applies to non-production related revenues has been included in all rate schedules. The energy tax reform statute exempts the following customers from the CBT provision, and when billed to such customers, the rates otherwise applicable under this tariff shall be reduced by the provision for the CBT (and related New Jersey Sales and Use Tax) included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey.

2. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

3. Special contract customers for whom a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

Rider SUT
Sales and Use Tax

APPLICABILITY: In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax ("SUT") has been included in all charges applicable under this tariff by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

A. The energy tax reform statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable under this tariff shall be reduced by the provision for the SUT included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey.

2. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

3. Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

4. Agencies or instrumentalities of the federal government.

5. International organizations of which the United States of America is a member.

B. The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c. 374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

1. A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and
2. A group of two or more persons: (a) each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the “Local Redevelopment and Housing Law,” P.L.1992, c.79 (C.40A:12A-1 et seq.); (b) that collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process; (c) are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and (d) collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.
3. A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c. 373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in B.1., B.2. or B.3. above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 et seq.) and P.L.1966, c.30 (C.54:32B-1 et seq.) and the Company has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

Rider RRC
RGGI Recovery Charge

APPLICABILITY: Rider RRC provides a charge for the costs associated with demand response/energy efficiency/renewable energy programs directed by the BPU as detailed below. The RGGI Recovery Charge (RRC) is applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

For service rendered effective January 1, 2020:

RRC = $0.000000 per KWH ($0.000000 per KWH including SUT)

The above RRC provides recovery for the followings:

Solar Renewable Energy Certificates Financing Program (SREC I & II)
Pursuant to BPU Orders dated March 27, 2009 and September 16, 2009 (Docket No. EO08090840) approving an SREC-based financing program (SREC I), pursuant to BPU Order dated December 18, 2013 (Docket No. EO12080750) approving the SREC II, and pursuant to BPU Order dated December 20, 2019 (Docket No. ER19070806) approving the Stipulation of Settlement, the Company shall include an SREC I & II Rate of $0.000000 per kWh in RRC effective January 1, 2020.

The RRC costs shall accrue interest on any over or under recovered balances of such costs at the interest rate based on a two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus sixty basis points, but shall not exceed the Company's overall rate of return as approved by the BPU. Such interest rate shall be reset each month. The interest calculation shall be based on the net of tax beginning and end average monthly balance, consistent with the methodology in the Board's Final Order dated May 17, 2004 (Docket No. ER02080506 et al.), compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

The RRC is subject to annual true-up.

Rider SRC
Storm Recovery Charge

APPLICABILITY: Rider SRC provides a charge for the recovery of the amortization of the deferred O&M costs associated with the 2012 major storm through November 30, 2019. The Storm Recovery Charge (SRC) is applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

SRC = $0.000000 per KWH ($0.000000 per KWH including SUT)

The SRC rate shall include carrying costs on the unamortized balance of the deferred O&M costs associated with the 2012 major storm. Such carrying costs shall be calculated on a monthly basis at an interest rate equal to the rate on seven-year constant maturity Treasuries, as shown in the Federal Reserve Statistical Release on or closest to January 1 of each year, plus sixty basis points, compounded annually as of March 31 of each year.

The calculated SRC rate shall be prepared by the Company and filed with the BPU annually by January 15 with a requested effective date of April 1 of the filing year. The first such filing shall be made by January 15, 2016 with actual and projected data for the 12-month period ending March 31, 2016.

The SRC rate was reduced to zero as of December 1, 2019. The final Rider SRC true-up will be filed by January 31, 2020. Any net ending over/under-recovered balance in the Rider SRC deferred balance will be applied to the largest under-recovered component of the Rider SBC deferred balance.

Rider ZEC
Zero Emission Certificate Recovery Charge

APPLICABILITY: The Zero Emission Certificate Recovery Chare (“Rider ZEC” or “ZEC Charge”) provides a charge for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities (“BPU” or “Board”) as detailed below. The ZEC Charge is applicable to all kWh usage of any Full Service Customer or Delivery Service Customer.

Per KWH		Including SUT
ZEC Charge	$0.004000	$0.004265
ZEC Reconciliation Charge	$0.000000	$0.000000
Total ZEC Charge	**$0.004000**	**$0.004265**

Pursuant to the BPU’s Zero Emission Certificate Charge Order dated November 19, 2018 in Docket No. EO18091002, the Board approved the implementation of a non-bypassable, irrevocable ZEC Charge of $0.004000 per KWH for all customers. The ZEC Charge reflects the emission avoidance benefits of the continued operation of selected nuclear plants as determined in L. 2018, c.16 (the “ZEC Law”). The ZEC Charge has been set at the rate specified in the ZEC Law and may be adjusted periodically by the Board, in accordance with the methodology provided for in the ZEC law.

In accordance with the ZEC Law, the proceeds of the ZEC Charge will be placed in a separate account, which amount the Company may use for general corporate purposes, with interest applied at the Company’s short-term borrowing rate as calculated each month, and will be used solely to purchase ZECs and to reimburse the Board for its reasonable, verifiable costs incurred to implement the ZEC program. Refunds will be provided to the customers served under each of the Company’s rate schedules in proportion to the ZEC Charge revenues contributed by the rate schedule.

Rider TAA
Tax Act Adjustment

APPLICABILITY: Rider TAA provides a credit resulting from the amortization and reconciliation of certain Excess Deferred Income Taxes ("EDIT"), including applicable carrying charges related to the impact of the Federal Tax Cuts and Jobs Act of 2017 ("Tax Act") on the Company's rates.

Effective **May 15, 2019**, the following TAA credits, including one time bill credit, (including Sales and Use Tax as provided in Rider SUT) will be applicable to all KWH usage of any Full Service Customer or Delivery Service Customer under Service Classification:

RS	**$0.006389 per KWH**
RT/RGT	**$0.006103 per KWH**
GS	**$0.005116 per KWH**
GST	**$0.003950 per KWH**
GP	**$0.002782 per KWH**
GT	**$0.001632 per KWH**
Lighting	**$0.027344 per KWH**

(includes OL, SVL, MVL, ISL and LED)

Effective **June 15, 2019**, the following TAA credits (including Sales and Use Tax as provided in Rider SUT) will be applicable to all KWH usage of any Full Service Customer or Delivery Service Customer under Service Classification:

RS	**$0.000310 per KWH**
RT/RGT	**$0.000307 per KWH**
GS	**$0.000274 per KWH**
GST	**$0.000213 per KWH**
GP	**$0.000154 per KWH**
GT	**$0.000093 per KWH**
Lighting	**$0.001567 per KWH**

(includes OL, SVL, MVL, ISL and LED)

Carrying Charges: Interest should not accrue on the outstanding net unprotected EDIT liability. No interest charges apply to over or under-recovered balances.

EXHIBIT JC-13

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Thomas R. Donadio

Re: Changes to the Company's Tariff for Service

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Thomas R. Donadio and my business address is 300 Madison Avenue, Morristown NJ, 07960.

Q. By whom are you employed?

A. I am employed by FirstEnergy Service Company as a Staff Analyst in the New Jersey Rates and Regulatory Affairs Department, which provides rates and regulatory services to and for Jersey Central Power & Light Company ("JCP&L" or the "Company"). I am providing this testimony on behalf of JCP&L in its base rate case proceeding.

Q. Please describe your professional experience and background.

A. My professional and educational background is attached to my testimony as Appendix A.

Q. Have you previously testified in proceedings before the Board of Public Utilities ("Board" or "BPU")?

A. Yes, I have. I previously provided testimony regarding the second phase of JCP&L's SREC-Based Financing Program in 2012 at BPU Docket No. EO12080750. The proposal was for a long-term contracting plan designed to support financing for a projected 52 MW of solar energy projects.

Q. Please describe the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe proposed changes to the Company's Tariff for Service, BPU No. 12 Electric ("Tariff").

Q. Please summarize your testimony.

A. JCP&L proposes modifications to Part I of the Tariff to revise the name of a municipality that has changed its name and to revise the street number address for a Company business office location. In addition, the Company proposes to increase the fee for returned check charges from $12.00 to $15.00 to more closely track the costs of processing return checks. JCP&L is also proposing to modify the calculation methodology to determine the equal monthly payment amounts for residential customers on the Equal Payment Plan ("EPP") as provided in Section 3.17 of the Company's Tariff for purposes of increased accuracy and conformity with the calculation methodology used by JCP&L's affiliate utility companies with similar budget billing plans. Furthermore, the Company proposes changes to the Net Metering provisions in Part II of the Tariff to incorporate the Community Solar Energy Pilot Program and Public Entity Remote Net Metering pursuant to revisions to Chapter 8, Subchapter 9, of Title 14 of the New Jersey Administrative Code ("N.J.A.C."). Finally, the Company proposes to remove the specified dollar amount listed as the $ per KWH rider charges on the Rate Service Classification pages of its Tariff and incorporate by reference the appropriate Tariff Rider pages for those components in the pages of Part III of the Tariff – Service Classifications and Riders. My testimony provides detailed support for these proposals.

Q. How is your testimony organized?

A. In addition to Section I, which contains this introduction, Section II of my testimony discusses the reasons behind the proposed changes to the Tariff Part I – General Information and Part II – Standard Terms and Conditions.

Section III explains the proposed additions reflecting the Community Solar Energy Pilot Program and Public Entity Remote Net Metering provisions contained in Part II of the Tariff, as well as the administrative modifications to the Rate Service Classification pages.

Q. Please indicate the schedules to your testimony and summarize the contents of those schedules.

A. My testimony contains four Schedules.

Schedule TD-1 contains the sample tariff sheets with the proposed revisions to Tariff Part I – General Information and Tariff Part II – Standard Terms and Conditions. The Tariff sheets provided in Schedule TD-1 are also found in Schedule YP-5, which contains complete copies of the current and proposed Tariffs and is attached and referred to in the testimony of Yongmei Peng (Exhibit JC-10).

Schedule TD-2 contains the worksheet supporting the revised returned payment charge.

Schedule TD-3 contains the proposed changes to the net metering provisions of Tariff Part II, which incorporates changes that reflect the Board's rules related to the Community Solar Energy Pilot Program and Public Entity Remote Net Metering.

Schedule TD-4 contains the administrative changes to certain pages of Tariff Part III – Service Classifications and Riders, which remove the $ per KWH rider charges on the Rate Service Classification pages and incorporate by reference the Tariff Rider pages for those components.

II. TERMS, CONDITIONS AND LANGUAGE MODIFICATIONS

Q. Please describe the changes that are proposed for Tariff Part I – General Information.

A. For Tariff Part I – General Information, the following changes are proposed:

The Company proposes to replace "South Belmar Boro" with "Lake Como Boro," which is the new name for that same municipality in General Information, Section G.

In addition, General Information, Section H is being revised to update the address of the Central Region Business Office in Old Bridge to "1345 Englishtown Road" from "999 Englishtown Road," which represents a revision to the street address number required for the 911 Emergency System.

Schedule TD-1 includes the proposed Tariff Part I revisions.

Q. Please describe the changes that are proposed for the Tariff Part II – Standard Terms and Conditions.

A. For Tariff, Part II – Standard Terms and Conditions, the Company is proposing to modify Subsection 3.18 – Returned Payment Charge. As indicated in TD-1 (Current Tariff Sheet No. 13; Proposed Tariff Sheet 13), the Company proposes to increase the fee for returned check charges from \$12.00 to \$15.00. In addition, the Company is also proposing to modify the calculation methodology to determine the equal monthly payment amounts for residential customers on the EPP as provided in Section 3.17 of the Tariff.

Q. Please explain why the Company is proposing this change to the Returned Payment Charge.

A. The proposed charge of $15.00 more accurately reflects the cost incurred by the Company for bank fees and increased labor charges resulting from processing returned checks. Schedule TD-2 contains the worksheet supporting the revised returned payment charge. The return check charge has been set at $12.00 since April 1, 2015 when it increased from $10.00. Schedule TD-2 would support a greater increase. However, in the interest of gradualism, the Company is seeking a more modest increase at this time.

JCP&L's proposal to increase the returned check charge is driven, in large part, by increased bank fees charged to the Company for processing such matters. The proposal also does not recover all costs associated with the processing and handling of the returned checks but represents a reasonable and gradual step towards that objective.

Q. Please describe the EPP.

A. The EPP for Individual Residential Dwelling Units is a program for residential customers requesting monthly budget billing. It is designed to make a residential customer's monthly payments consistent throughout an entire year, leveling out seasonal highs and lows. At the residential customer's request, the Company shall estimate the customer's monthly billing charges for a twelve-month period and create an EPP for the customer.

Once established at the customer's request, the EPP account will undergo an interim review during the EPP billing year to determine whether an increase or decrease in the monthly EPP billing amount is warranted. The interim review process occurs once automatically during the annual billing cycle. A customer's

EPP payment amounts are adjusted if the customer's actual monthly charges for electric service are lower or higher than the monthly estimated EPP amounts where the percent difference between actual and estimated is equal to, or greater than, 25%, or the difference is greater than $10.

If the review results in a change in the EPP amount to be charged, the information will be placed on the billing statement for that month, advising the customer of the new amount, and the next month's bill will reflect the new amount to be paid by that month's billing due date. The interim review helps to reduce or avoid large reconciliation bills at the end of the budget plan year.

During the twelfth month (or in the event the EPP is cancelled or terminated before the end of the budget year), the EPP is trued-up as reflected in the bill for the twelfth or concluding month, which will be sent to the customer. The customer is responsible for the current EPP charge for the twelfth or concluding month plus any positive difference between the actual charges and the EPP amount for the budget plan year (or shorter period in the case of earlier cancellation or termination of the EPP). An information box will be placed on the twelfth or concluding month bill advising the customer of the new amount to be paid by the due date of such bill. If a credit exists at the twelfth or concluding month, it will be applied against the current month bill amount. This annual true-up will also establish the EPP monthly amount for the next budget plan year.

Q. Please describe the current EPP calculation methodology.

A. The EPP estimation is calculated by adding the total annual billing amount charged for the prior year, dividing that dollar amount by the number of days in that 12-

month billing history, then multiplying by 30 to arrive at the equal monthly payment under the EPP. If the customer does not have one full year of billing history, estimates may be based upon the previous billing history at the premises or using another reasonable estimation method.

Q. Please explain the Company's proposed changes to the EPP.

A. The Company is only proposing to change the multiplication factor of the estimation calculation from "30", which is based on a 360-day year (as the denominator), to "30.4," which is based on an actual year of 365 days. Although the calculation methodology is not specifically mentioned in the Tariff, the Board's regulations require that "any change in a utility's budget billing plan program, … be filed and approved by the Board through a tariff amendment prior to its implementation." N.J.A.C. 14: 3-7.5(k).

Q. Why does the Company propose to change the multiplication factor of the estimation calculation?

A. This change will benefit customers on the EPP by helping to ensure that the EPP monthly payment amount provides a more accurate reflection of a customer's usage over time. In addition, since JCP&L's affiliate utility companies in other states use an EPP methodology with a 30.4 multiplication factor, the change in the calculation should result in added billing process efficiency. Finally, this change will promote consistency for the Company's customer service representatives when explaining the EPP to customers in different states.

III. <u>CHANGES TO THE NET METERING TARIFF INCLUDED IN TARIFF PART II</u>

Q. Please describe the changes that are proposed in Tariff Part II – Standard Terms and Conditions: Net Metering Tariff.

A. The Company is also proposing to revise the Tariff to reflect statutory changes related to Remote Net Metering and the Community Solar Energy Pilot Program, which were adopted after the Company's last base rate case.[1]

Schedule TD-3 outlines the proposed additions, which include certain references to limitations and qualifications, sizing requirements, billing and bill credit processes consistent with the Board's regulations. Schedule TD-3 also provides a general overview of eligibility to become a Remote Net Metering customer-generator and the types of eligible renewable energy resources consistent with the Board's order dated September 17, 2018 at BPU Docket No. QO18070697.

Q. Please describe the changes that are proposed in Tariff, Part III – Service Classifications and Riders.

A. As reflected in Schedule TD-4, the Company is proposing changes to Tariff, Part III – Service Classifications and Riders to remove the $ per KWH Rider charges that appear on these pages and instead incorporate the pertinent charging data by reference to the Tariff Rider pages for these components of the Service Classification charges.

The purpose of this change is to eliminate the administrative burden of revising multiple Tariff pages when the rates for Rider recovery change following

[1] The Board's community solar rules are found at N.J.A.C. 14:8-9.1 – 9.11. The Board has not yet formally adopted regulations to implement remote net metering.

approval of annual Rider filings. This is not a substantive change. There are no substantive changes proposed for Tariff, Part III.

Q. Does this conclude your direct testimony?

A. Yes, it does.

THOMAS R. DONADIO

PROFESSIONAL AND EDUCATIONAL BACKGROUND

I am a NJ State Regulatory Analyst V in the NJ Rates and Regulatory Affairs Department for FirstEnergy Service Company, providing support primarily for Jersey Central Power & Light Company. I have worked over 30 years in the energy industry. Currently, my primary responsibilities as Analyst V include serving as JCP&L's primary regulatory liaison to Board Staff and coordinating various regulatory reporting requirements. I also provide analysis and direction to senior Company staff pertaining to pending legislative initiatives, as well as proposed rules and amendments to existing rules in the New Jersey Administrative Code that affect the Company including coordinating the Company's comments regarding them.

In my employment with FirstEnergy or predecessor companies, I have served in a number of capacities, including customer service, meter reading supervision, financial planning and analysis, business development and regulatory programs, including over 10 years' experience developing and implementing programs supporting energy efficiency, renewable energy and demand response programs. I have managed the JCP&L SREC-Based Financing programs since inception, participating in the initial design and regulatory proceeding, and assumed a leading role in the regulatory approval of its successor SREC program. I was awarded a Bachelor of Arts in Business Management from Moravian College and earned an MBA in Corporate Finance from Fairleigh Dickinson University.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU NO. 12 ELECTRIC ORIGINAL TITLE SHEET

TARIFF for SERVICE

Part I

General Information

Part II

Standard Terms and Conditions

Issued: Effective:

Filed pursuant to Order of Board of Public Utilities
Docket No. dated

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

General Information

G - Municipalities Served: The following list designates those municipalities in which the Company serves the public through its distribution facilities.

BURLINGTON COUNTY
Chesterfield Twp.
New Hanover Twp.
North Hanover Twp.
Pemberton Boro
Pemberton Twp.
Southhampton Twp.
Springfield Twp.
Woodland Twp.
Wrightstown Boro

ESSEX COUNTY
Livingston Twp.
Maplewood Twp.
Millburn Twp.

HUNTERDON COUNTY
Alexandria Twp.
Bethlehem Twp.
Bloomsbury Boro
Califon Boro
Clinton, Town of
Clinton Twp.
Delaware Twp.
East Amwell Twp.
Flemington Boro
Franklin Twp.
Frenchtown Boro
Glen Gardner Boro
Hampton Boro
High Bridge Boro
Holland Twp.
Kingwood Twp.
Lambertville, City of
Lebanon Boro
Lebanon Twp.
Milford Boro
Raritan Twp.
Readington Twp.
Stockton Boro
Tewksbury Twp.
Union Twp.
West Amwell Twp.

MERCER COUNTY
East Windsor Twp.
Hightstown Boro
Hopewell Twp.
Washington Twp.
West Windsor Twp.

MIDDLESEX COUNTY
Cranbury Twp.
East Brunswick Twp.
Helmetta Boro
Jamesburg Boro
Monroe Twp.
Old Bridge Twp.
Sayreville Boro
South Amboy, City of
South Brunswick Twp.
Spotswood Boro

MONMOUTH COUNTY
Aberdeen Twp.
Allenhurst Boro
Asbury Park, City of
Atlantic Highlands Boro
Avon-by-the Sea Boro
Belmar Boro
Bradley Beach Boro
Brielle Boro
Colts Neck Twp.
Deal Boro
Eatontown Boro
Englishtown Boro
Fair Haven Boro
Farmingdale Boro
Freehold Boro
Freehold Twp.
Hazlet Twp.
Highlands Boro
Holmdel Twp.
Howell Twp.
Interlaken Boro
Keansburg Boro
Keyport Boro

MONMOUTH COUNTY (Continued)
Lake Como Boro
Little Silver Boro
Loch Arbour, Village of
Long Branch, City of
Manalapan Twp.
Manasquan Boro
Marlboro Twp.
Matawan Boro
Middletown Twp.
Millstone Twp.
Monmouth Beach Boro
Neptune City Boro
Neptune Twp.
Oceanport Boro
Ocean Twp.
Red Bank Boro
Roosevelt Boro
Rumson Boro
Sea Bright Boro
Sea Girt Boro
Shrewsbury Boro
Shrewsbury Twp.
~~South Belmar Boro~~
Spring Lake Boro
Spring Lake Heights Boro
Tinton Falls Boro
Union Beach Boro
Upper Freehold Twp.
Wall Twp.
West Long Branch Boro

MORRIS COUNTY
Boonton, Town of
Boonton Twp.
Butler Boro
Chatham Boro
Chatham Twp.
Chester Boro
Chester Twp.
Denville Twp.
Dover, Town of
East Hanover Twp.

General Information

H – Customer Contact Information:

Emergency / Power Outage Reporting	1-888-544-4877
General Customer Service	1-800-662-3115
Payment Options	1-800-962-0383
Telecommunications Relay Service (TRS) for the Hearing Impaired	711
Morristown General Office 300 Madison Avenue, Morristown, NJ 07962-1911	1-973-401-8200

Customer Billing Questions or Complaints
JCP&L 76 S. Main Street, A-RPC, Akron, OH 44308-1890

Website:
http://www.firstenergycorp.com

Northern Region Business Offices:

Morristown	300 Madison Avenue, Morristown, NJ 07962	**ALL TELEPHONE INQUIRIES PLEASE USE CUSTOMER CONTACT INFORMATION ABOVE**
Hopatcong	175 Center Street, Landing, NJ 07850	
Phillipsburg	400 Lincoln Street, Phillipsburg, NJ 08865	

Central Region Business Offices:

Allenhurst	300 Main Street, Allenhurst, NJ 07711
Toms River	25 Adafre Avenue, Toms River, NJ 08753
Old Bridge	~~999~~ 1345 Englishtown Road, Old Bridge, NJ 08857

Section 3 - Billings, Payments, Credit Deposits & Metering

3.14 Taxes on Contributions in Aid of Construction and Customer Advances or Deposits: Any contribution in aid of construction ("CIAC"), customer advance or deposit, or other like amount received from Customers which shall constitute taxable income as defined by the Internal Revenue Service may be increased to include a payment equal to the applicable current taxes incurred by the Company as a result of receiving such monies, less the net present value of future tax benefits related to the tax depreciation guideline-life applicable to the property constructed with such monies, which for transmission or distribution items shall be taken to be 20 years. The discount rate to be used for such present value calculation will be the Company's last allowed overall rate of return.

3.15 Unmetered Service: Where the Customer's equipment is of such a character and its operation is so conducted that the Customer's use of service at the Point of Delivery is substantially invariable over the period Service is supplied, thus permitting accurate determination of billing quantities by calculation based on the electrical characteristics of such equipment, the Company may omit the installation of metering equipment and, with the consent of the Customer, use the respective quantities, so determined, for billing purposes under the applicable Service Classification. The Customer shall not make any change whatever in the equipment or mode of operation thereof, Service to which is billed in the foregoing manner, without first obtaining the Company's consent in writing. If the Customer changes equipment or mode of operation, any Service to such changed equipment or operation shall be deemed unauthorized use and shall be subject to discontinuance as provided elsewhere in this Tariff.

3.16 Non-measurable Loads: Customers with equipment which creates unusual fluctuations, which cannot be measured by standard metering facilities, shall have the maximum 15-minute demand, monthly KWH, and reactive component calculated for such equipment, and added to any such measured quantities for the customer's remaining load for billing purposes under the applicable Service Classification.

3.17 Equal Payment Plan for Individual Residential Dwelling Units: The Company may, upon request by a residential Full Service Customer, determine a payment plan of twelve equal monthly payments for the Customer. Monthly payments required under this plan may be revised by the Company one time during the payment plan period as rate changes or special conditions warrant. If actual charges are more or less than the estimated amounts, billing adjustments necessary to provide for the payment of the actual charges due for Service rendered under this plan shall be made in the twelfth month of the plan, or in the event the Equal Payment Plan is terminated, on the next bill. The Company may terminate this plan at any time as to any Customer if any monthly bill rendered to such Customer under this plan is unpaid when the next monthly bill is rendered. (See NJAC 14:3-7.5)

3.18 Returned Payment Charge: A charge of $~~12~~ 15 will be assessed against a Customer's account when a check or an electronic payment or other form of funds transfer, which has been issued to the Company, is returned by the bank as uncollectible, or otherwise dishonored by the bank from which the funds were drawn.

Jersey Central Power & Light Company
Miscellaneous Charges Worksheet
Returned Payment Charge

Remittance Center - Process Return Payments		
Average wage per hour - Sr. Customer Accounting Associate (non-bargaining) (2)	Average Time in Minutes Per Return (1)	Cost Per Collection Call
$ 24.75	6	$ 2.48

Business Office / Back Office Support - Reschedule for Disconnection / Field Inquires		
Average wage per hour - Customer Service Representative - Level 3 (Bargaining) (2)	Average Time in Minutes Per Return (1)	Cost Per Collection Call
$ 30.79	5	$ 2.57

Contact Center - Customer Inquires		
Average wage per hour - Customer Service Representative - Level 3 (Bargaining) (2)	Average Time in Minutes Per Return (1)	Cost Per Collection Call
$ 19.34	0.5	$ 0.16

TOTAL LABOR COSTS	**$ 5.21**
Postage (3)	$ 0.55
Average Bank Fees	$ 12.54

Overhead (Labor Related Expense)			
$ 2.48	44.43%	non-bargaining	$ 1.10
$ 2.73	39.10%	bargaining	$ 1.07
$ 5.21	**Total**		**$ 2.17**

TOTAL NON-LABOR COSTS	**$ 15.26**
TOTAL COST BASED CHARGE	**$ 20.47**

Current Charge	$ 12.00
Proposed Charge (4)	$ 15.00

(1) Average Times Estimated by Customer Service Management.
(2) Labor Rate based on 2019. Bargaining rates based on union contracts.
(3) Postage cost based on mailing first class 1 ounce letter using a standard stamp.
(4) This charge will be rendered for returned items subject to a charge.

Section 12 – Net Metering Installations

12.01 General: For the purpose of this Section of the Tariff for Service a Customer-generator is an electricity customer such as an industrial, commercial or residential customer that generates electricity using Class 1 renewable resources as defined in NJAC 14:8-1.2 on the customer's side of the meter. Net metering, as defined in Section 12.02 below, provides for the billing or crediting, as applicable, of energy usage by measuring the difference between the amount of electricity delivered by the Company to a Customer-generator, as defined in Section 12.02 below, in a given Billing Month and the electricity delivered by a Customer-generator into the Company distribution system. The Company reserves the right to select and supply the type of meter(s) that will enable the net metering of electricity as described above.

The Customer generator shall be responsible for all interconnection costs as defined in NJAC 14:8-5.7 et seq., which shall be in addition to any other charges applicable to meet service requirements. For customers eligible for Net Metering the term usage as applied in Section 2.05 shall mean net usage as determined by Net Metering. It is the Customer-generator's responsibility to know all of the rules associated with the provision of net metering service.

12.02 Limitations and Qualifications for Net Metering: "Net metering" means a system of metering and billing for electricity in which the Company 1) credits a customer-generator at the full retail rate for each kilowatt-hour produced by a Class 1 renewable energy system installed on the customer-generator's side of the electric revenue meter, up to the total amount of electricity used by that customer-generator during an annualized period determined under NJAC 14:8-4.3 and 2) compensates the customer-generator at the end of the annualized period determined under NJAC 14:8-4.3 for any remaining credits, at a rate equal to the avoided cost of wholesale power. To qualify for Net Metering, a Customer-generator must generate Class 1 renewable energy as defined in NJAC 14:8-1.2. The Company will offer net metering to any customer that generates Class 1 renewable electricity on the customer's side of the meter provided that the generating capacity of the Customer-generator's facility does not exceed the amount of electricity supplied by the Company over an Annualized period (as defined in NJAC 14:8-4.3).

12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)): To qualify for Aggregated Net Metering a customer must be: a state entity, school district, county, county agency, county authority, municipality, municipal agency, or municipal authority that has multiple facilities with metered accounts to be known collectively as the "Aggregated Meters." The Aggregated Meters must be: located within the Company's territory; served under the same rate schedule; all served by either Basic Generation Service or by the same Third Party Supplier; and located within the customer's territorial jurisdiction or, for a State entity, located within 5 miles of one another. One of the Aggregated Meters must operate a Class 1 solar electric power generation system using a net metered account as defined in Section 12.02, Limitations and Qualifications for Net Metering, except for the annualized electric generation capability limitation. The Qualified Customer-Generator must be located on property owned by the customer. The size of the Qualified Customer-Generator for Aggregated Net Metering is defined in Section 12.03.a, Customer-Generator Sizing Qualifications for Aggregated Net Metering.

Section 12 – Net Metering Installations

12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)): (Continued)

a) **Customer-Generator Sizing Qualifications for Aggregated Net Metering:** The annualized electric generation capability of the customer's solar generating system, located at the net metered location cannot exceed the amount of electricity supplied by the electric power supplier or basic generation service provider to all of the Aggregated Meters over an annualized period. The Aggregated Meters used to determine the maximum annualized electric generation capability of the customer's solar generating system may not be used to determine the maximum annualized electric generation capability of other aggregated net metered facilities nor become a Qualified Customer-Generator as defined in Section 12.02, Limitations and Qualifications for Net Metering.

b) **Billing for Aggregated Net Metering**: The Qualified Customer-Generator will be billed as defined in Section 12.06, Net Metering Billing. However, Section 12.06, Net Metering Billing will not apply to the other Aggregated Meters and those meters will continue to be billed at the full retail rate pursuant to the applicable rate schedules.

c) **Incremental Costs Associated with Aggregated Net Metering:** All incremental costs incurred by the Company resulting from the implementation of Aggregated Net Metering shall be recovered from Aggregated Net Metering customers.

12.04 Limitations and Qualifications for Remote Net Metering (BPU Docket No. QO18070697, Order dated September 17, 2018): The Clean Energy Act, P.L. 2018, Chapter 17, Section 6 required the BPU to establish an application and approval process to facilitate Remote Net Metering in which a public entity certified to act as a host customer with a solar electric energy project may allocate credits to other public entities within the same electric public utility service territory To qualify for Remote Net Metering a customer must be a public entity, which is a State entity, school district, county, county agency, county authority, municipality, municipal agency, municipal authority or public university that has completed the BPU-approved application process and received BPU approval for certification as a participant eligible to receive Remote Net Metering credits. A host customer is a public entity that proposes to host a solar electric generation facility on its property. The entities designated to receive credits are considered to be receiving customers that are public entities located in the same electric distribution company ("EDC") territory as the host customer. Both the host customer and the receiving customer must be a customer of record of JCP&L, and there may be no more than ten receiving customer accounts per host.

Eligible public entities must follow the established application and approval process to certify public entities to act as a host customer for Remote Net Metering, requiring submittal of the BPU-approved form of "Public Entity Certification Agreement" used by the host customers and receiving customers which shall be fully executed and provided to the Company, reviewed by the Staff of the BPU and approved by the BPU prior to the application of any Remote Net Metering credits. The Public Entity Certification Agreement is available on the New Jersey Clean Energy Program website as well as the Company's website in the section dedicated to information regarding net metering and interconnection processes. The standard form "Public Entity Certification Agreement' must be fully executed by the host customer

Section 12 – Net Metering Installations

and each receiving customer, be accompanied by the BPU-approved standard form of Interconnection Application (Part 1) as used for all net metered projects and be delivered to both BPU Staff and the Company. The Company and BPU Staff will review the Public Entity Certification Agreement for administrative completeness. Within 10 days, the Company will provide its input to BPU Staff, whereupon BPU Staff will issue a notice of its findings to the contact person listed on the form. Following the issuance of a notice of administrative completeness, the Company will have twenty business days to review the application for eligibility and feasibility, including the proposed system size and all account information and make a recommendation to BPU Staff to approve or deny. In the case of a recommendation of denial, the Company will provide to BPU Staff a description of the deficiencies and potential means to correct the deficiencies. BPU Staff will present the fully executed "Public Entity Certification Agreement" and Part 1 of the Interconnection application to the BPU with a recommendation for approval or denial.

a) **Host Customer Solar Electric Generator Sizing for Remote Net Metering:** The size of a host customer's solar electric generation facility shall be limited to the installed capacity that can produce electricity on an annual basis in an amount not to exceed the total average usage of the host customer's electric accounts with the Company. The host customer is not required to use more than one account for purposes of sizing the solar electric generation facility. However, the solar facility must be located on property containing at least one Company electric meter for the host customer. The host customer is required to identify which account(s) to use to calculate the total average usage for the previous twelve months of consumption in kWhs. The total quantity of annual, historic consumed kWh will be divided by (i) the number of accounts, if more than one account is used, and (ii) 1,200 annual kWh per kilowatt ("kWdc") to arrive at the maximum capacity for the solar electric generation facility in kWs.

Billing and Credits for Remote Net Metering: No more than ten receiving accounts may be party to a Public Entity Certification Agreement and not less than 10% of the solar electric generating facility output may be allocated to an individual receiving account. The terms and conditions of the Public Entity Certification Agreement, including all designated receiving accounts and their associated percentage of output allocations, shall be fixed throughout the annualized period with the exception of a once per annum opportunity to reallocate upon BPU Staff's approval of a revision to a Public Entity Certification Agreement, which is re-executed with all parties' approval, including the Company. The host customer shall agree to the installation of a revenue grade production meter at its expense as specified by the Company, to record the solar generation at the host site. On a monthly basis, the Company shall use the metered kWh data produced by the solar electric generation facility on the host customer property to calculate the credits due to receiving customers. The monthly output will be allocated to receiving customers according to the percentage allotments indicated on the Public Entity Certification Agreement. The value of a Remote Net Metering credit will reflect a rough approximation of the generation, transmission and distribution value of a kWh produced by the solar electric generation facility. Each credited kWh for a receiving customer shall offset the variable kWh charges of a receiving customer(s) except for the SBC charge. No fixed, demand ($/kW), customer or SBC charges shall be offset by a remote net metering credit. On a monthly basis, the Company will credit an apportioned amount of kWh output from the solar facility in the form of kWh to be deducted from the kWh consumed by the receiving

Section 12 – Net Metering Installations

customer. The apportioned amount of solar electricity generated in kWh, the gross amount of electricity consumed and the net amount of kWh after credit allocation will be identified on the monthly electric bills of the designated receiving customer account. The receiving customers will be charged the SBC amounts attributable to the apportioned credit kWh. The application of an annualized period as currently used in the net metering rules at N.J.A.C. 14:8-4.2 shall apply to remote net metering. Any excess generation for an individual receiving customer account after a monthly credit allocation shall be carried over to the next month within the annualized period. If an individual receiving customer account holds credits at the end of an annualized period, the account shall be trued up consistent with current net metering practice, with excess kWh compensated at the average annual LMP in the Company's transmission zone.

b) **Incremental Costs Associated with Remote Net Metering:** All incremental costs incurred by the Company resulting from the implementation of Remote Net Metering shall be recovered from Remote Net Metering customers.

12.05 Installation Standards: A Customer-generator shall comply with the requirements of the Company which are set forth in detail in the Application/Agreement Parts 1 and 2 for Level 1 Projects or the Interconnection Application and Agreement for Level 2 or Level 3 Projects both of which are approved by the New Jersey Office of Clean Energy and available at www.firstenergycorp.com. In addition, the Customer-generator shall be responsible for meeting all applicable safety and power quality standards as set forth below.

The Customer-generator's facility shall comply with all applicable safety and power quality standards specified by the National Electrical Code, Institute of Electrical and Electronics Engineers, and accredited testing institutions, such as Underwriters Laboratories. The Customer-generator's facility should be constructed and installed in accordance with the State of New Jersey Uniform Construction Code requirements for electrical installations, UL 1741 and the IEEE Standard 1547. Net Metering systems served by network distribution systems, shall comply with standards established by the Company and approved by the BPU in addition to the aforementioned applicable safety and power quality standards and all other requirements in NJAC 14:8-5.2 et seq.

Section 12 – Net Metering Installations

12.06 Initiation of Service: Prior to interconnecting with the Company's distribution system the Customer-generator is required to provide the Company with an Interconnection Application/Agreement Parts 1 and 2 for Level 1 projects or an Interconnection Application and Agreement for Level 2 or Level 3 Projects and must also pay all appropriate charges as detailed in these applications. Additionally, the Company may, at its option, inspect the interconnection prior to the initiation of Net Metering service.

Initiation of service will become effective on the Customer-generator's first regularly scheduled meter reading date that is at least twenty (20) days after the Customer-generator elects to take service under or to be billed under or in accordance with this provision, by executing an Interconnection Application, but in no case prior to the installation of the necessary meter(s), and shall terminate at a regularly scheduled meter reading date that is at least twenty (20) days following the receipt by the Company of Customer-generator's notification of termination or from the date that the Company determines that the customer-generator is no longer eligible for net metering service pursuant to NJAC 14:8-4.1 et seq.

12.07 Net Metering Billing: In any Billing Month during an Annualized period, where the amount of electricity delivered by the Customer-generator plus any kilowatt-hour credits held over from the previous Billing Month or Billing Months exceeds the electricity supplied by the Customer-generator's electric supplier or basic generation service provider, as applicable, the excess kilowatt-hours shall be credited to the Customer-generator in the next Billing Month during the Annualized period. At the end of the Annualized period, the Customer-generator will be compensated for any remaining credits by the Customer-generator's electric supplier or basic generation service provider, as applicable, at the avoided cost of wholesale power (as defined at NJAC 14:8-4.2).

A Customer-generator shall have a one-time opportunity to select a Billing Month as the start of the Customer-generator's Annualized period. This selection will become effective on the first regularly scheduled meter reading date that is at least twenty (20) days after the Customer-generator notifies the Company of the Customer-generator's selection under the one-time opportunity provided in NJAC 14:8-4.3 (f) – (j).

In the event that a Customer-generator changes suppliers, the electric power supplier or basic generation service provider with whom service is terminating shall treat the end of the service period as if it were the end of the Annualized period and shall compensate the Customer-generator for any remaining credits at the avoided cost of wholesale power.

12.08 Program Availability: The Company may be authorized by the BPU to cease offering net metering whenever the total rated generating capacity owned and operated by Customer-generators on a Statewide basis equals ~~2.9~~ 5.8 percent of total annual kilowatt-hour sales in the State.

Section 13 – Community Solar Energy Pilot Program

13.01 General:

The Community Solar Energy Pilot Program is open to customers of all rate classes who subscribe to solar projects that are approved by the BPU. Projects and customer subscribers to those approved projects must meet the following minimum requirements, and the full requirements defined in N.J.A.C. 14:8-9.1, *et seq.*, in accordance with N.J.S.A. 48:3-87.11. The program provides for the participation of customers of the Company in all rate classes as subscribers to BPU-approved solar projects that are located within the service territory of the Company, but may be remotely located from the subscriber's electric service address, and receive a credit on their utility bills in accordance with their participation share. Existing solar projects may not apply to requalify as a Community Solar Energy Pilot Program project. The Pilot Program shall run for a period of no more than 36 months, divided into Program Year 1 (PY1), Program Year 2 (PY2), and Program Year 3 (PY3). PY1 shall begin February 19, 2019, and last until December 31, 2019. Subsequent program years shall begin on January 1 and last for the full calendar year. For each of the three program years, BPU staff shall initiate an annual application process. The annual capacity limit in the Company's service territory each year shall be approximately 20.625 MW based upon its 27.5% share of the 75 MW available statewide capacity. Any unallocated capacity at the end of a program year may be reallocated to subsequent program years. At least 40 percent of the annual capacity limit shall be allocated to low and moderate income community (LMI) projects. The application and criteria for selection of projects is managed by the BPU. Only projects that are selected by the BPU will be eligible to participate in the program. The capacity limit for individual community solar pilot projects is set at a maximum of five MWs per project, measured as the sum of the nameplate capacity in DC rating of all PV panels comprising the community solar facility. The minimum number of participating subscribers for each community solar project shall be set at 10 subscribers and the maximum number of participating subscribers for each community solar project shall be set at 250 subscribers per one MW installed capacity (prorated to project capacity). Each project must be equipped with at least one utility grade meter to facilitate the recording of solar generation underlying the bill credit process.

13.02 Selected Definitions (N.J.A.C. 14:8-9.2):

"Community solar pilot project," "community solar project," or "project" refers to a community solar project approved by the BPU for participation in the Pilot Program, including, but not limited to, the community solar facility, project participants, and subscribers.

"Community solar subscriber organization" or "subscriber organization" means the entity, duly registered with the BPU that works to acquire original subscribers for the community solar project and/or acquires replacement subscribers over the lifetime of the community solar project and/or manages subscriptions for a community solar project. The community solar subscriber organization may or may not be, in whole, in part, or not at all, organized by the community solar developer, community solar owner, or community solar operator.

"Community solar subscriber" or "subscriber" refers to any person or entity who participates in a community solar project by means of the purchase or payment for a portion of the capacity and/or energy produced by a community solar facility. One electric meter denotes one subscriber.

"Community solar subscription" or "subscription" refers to an agreement to participate in a community solar project, by which the subscriber receives a bill credit for a portion of the community solar capacity and/or energy produced by a community solar facility. A subscription may be measured as capacity in kW and/or energy in kWh, ownership of a panel or panels in a community solar facility, ownership of a share of a community solar project, or a fixed and/or variable monthly payment to the project operator.

Section 13 – Community Solar Energy Pilot Program

13.03 Subscription Requirements:

Community solar pilot project subscriptions shall not exceed 100 percent of the subscriber's historic annual usage, calculated over the past 12 months, available at the time of the application. In cases where a 12-month history is not available, the community solar subscriber organization shall estimate, in a commercially reasonable manner, a subscriber's load based on available history. No single subscriber shall subscribe to more than 40 percent of a community solar project's total annual net energy. Subscriptions are portable, provided that the subscriber remains within the original Company service territory as the community solar pilot project to which they are subscribed. Appropriate notice of the change in residence and/or location must be provided to the Company, no later than 30 days after the effective date of the change in residence and/or location. In cases of relocation, subscribers are entitled to one revision per move to their subscription size to account for a change in average consumption. Subscriptions may be sold or transferred back to the project owner or community solar subscriber organization by subscribers as specified in their subscription agreements. Subscribers may not sell or transfer a subscription to another party other than the project owner or community solar subscriber organization. A subscriber may not participate in more than one community solar project. It is the responsibility of the subscriber organization to verify that their subscribers are not already subscribed to another community solar project.

13.04 Community solar bill credits

Participating subscriber customers will receive a dollar-based bill credit for their subscribed percentage of the monthly kilowatt-hour output of the community solar project in proportion to the subscriber's share of the community solar project as indicated on the most recent list received from the subscriber organization. The monthly dollar credit on the subscriber’s bill will be the equivalent of their subscription percentage of the community solar project monthly kilowatt-hour generation amount applied to all kilowatt-hour charges on the subscriber’s bill, excluding all fixed and non-by-passable charges and SUT. The non-bypassable charges are the fixed monthly customer charge, all kW demand charges (if applicable), the SBC charge, the NGC charge and the ZEC charge. The value of the bill credit shall be set at the weighted class average retail rate for their respective service classification. The bill credit for CIEP eligible customers will be set at the average hourly energy price. Customers served by a third-party supplier will have their clscredit based upon the BGS rate. The subscriber’s bill credit will be used to offset the subscriber’s total bill up to the amount of actual metered consumption. The calculation of the value of the bill credit shall remain as described above and shall remain in effect for the life of the project, defined as no more than 20 years from the date of commercial operation of the project or the period until the project is decommissioned, whichever comes first, in addition to any modifications subsequently ordered by the BPU. The community solar bill credit will be specifically identified as the community solar bill credit in a separate line on the subscribers' utility bills.

Section 13 – Community Solar Energy Pilot Program

An annualized period shall be established for each subscriber. The annualized period shall begin on the day a subscriber first earns a community solar bill credit based on the delivery of energy, and continues for a period of 12 months, until the subscription ends, or until the subscriber's Company account is closed, whichever occurs earlier. The Company may sync up the monthly billing period of subscribers and projects, by modifying, with due notice given, the monthly billing period for subscribers upon their first month of participation in the community solar project. Excess credits above the level of the metered monthly consumption shall carry over from monthly billing period to monthly billing period, with the balance of credits accumulating until the earlier of either the end of the annualized period, the closure of the subscriber's Company account, or the end of the subscriber's community solar subscription. At the end of the annualized period and/or when a subscriber's Company account is closed and/or at the end of the subscriber's community solar subscription, any excess net bill credits greater than the sum of all appropriate billable charges shall be compensated at the Company's average LMP of the JCP&L transmission zone. The excess compensation must be returned to the subscriber by bill credit, wire transfer, or check. If a subscriber receives net excess credits for each of the three previous consecutive years, the subscriber organization must resize the subscriber's subscription size to ensure it does not exceed 100 percent of historic annual usage, calculated over the past 12 months, available at the time of the reassessment.

Any generation delivered to the grid that has not been allocated to a subscriber may be "banked" by the project operator in a dedicated project Company account for an annualized period of up to 12 months. The banked credits may be distributed by the project operator to any new or existing subscriber during that 12-month period, in conformance with subscription requirements set forth in N.J.A.C. 14:8-9.6. At the end of the up to 12-month period, any remaining generation credits shall be compensated at the Company's average LMP of the JCP&L transmission zone. Subscribers must have an active electric account within the Company's service territory of the community solar project to which they are subscribed. Upon Company request, If required by the Company, subscribers must agree to a remote read smart meter upon EDC request, purchased and installed at EDC cost.

The Company will utilize a standardized process for sharing subscriber information between subscriber organizations and the Company by which subscriber organizations can submit the lists of subscribers. Subscriber organizations shall send to the Company a list of subscribers to the project with all appropriate subscriber information, no later than 60 days prior to the first monthly billing period for the community solar project. Additionally, subscriber organizations shall send an updated list to the Company once per month.

TARIFF for SERVICE

Part III

Service Classifications and Riders

JERSEY CENTRAL POWER & LIGHT COMPANY

15th Rev. Sheet No. 4
BPU No. 12 ELECTRIC - PART III Superseding 14th Rev. Sheet No. 4

Service Classification RS
Residential Service

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
~~$0.000492~~ **See Rider NGC for rate** per KWH for all KWH including Off-Peak/Controlled Water Heating

4) **Societal Benefits Charge (Rider SBC):**
~~$0.007013~~ **See Rider SBC for rate** per KWH for all KWH including Off-Peak/Controlled Water Heating

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

6) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, a contract of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

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Docket Nos. and dated

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification RT
Residential Time-of-Day Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RT is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RS. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.007973** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $5.19** per month
Solar Water Heating Credit: $1.30 per month

2) **Distribution Charge:**
$0.046298 per KWH for all KWH on-peak for June through September
$0.034008 per KWH for all KWH on-peak for October through May
$0.021627 per KWH for all KWH off-peak

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
~~$0.000492~~ See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
~~$0.007013~~ See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

Service Classification RGT
Residential Geothermal & Heat Pump Service

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
~~$0.000492~~ See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
~~$0.007013~~ See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM Eastern Standard Time, Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high-density areas. The off-peak hours will not, however, be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, contracts of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GS

General Service Secondary

KWH Charge:

June through September (excluding Water Heating and Traffic Signal Service):

$0.059299 per KWH for all KWH up to 1000 KWH
$0.004743 per KWH for all KWH over 1000 KWH

October through May (excluding Water Heating and Traffic Signal Service):

$0.054868 per KWH for all KWH up to 1000 KWH
$0.004743 per KWH for all KWH over 1000 KWH

Water Heating Service:

$0.016517 per KWH for all KWH Off-Peak Water Heating
$0.021756 per KWH for all KWH Controlled Water Heating

Traffic Signal Service:

$0.012427 per KWH for all KWH

Religious House of Worship Credit:

$0.030231 per KWH for all KWH up to 1000 KWH

3) **Non-utility Generation Charge (Rider NGC):**
~~$0.000492~~ See Rider NGC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

4) **Societal Benefits Charge (Rider SBC):**
~~$0.007013~~ See Rider SBC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

7) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

9) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

Service Classification GST
General Service Secondary Time-Of-Day

3) **Non-utility Generation Charge (Rider NGC):**
~~$0.000492~~ See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
~~$0.007013~~ See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off-peak

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

9) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

JERSEY CENTRAL POWER & LIGHT COMPANY

20th Rev. Sheet No. 17

BPU No. 12 ELECTRIC - PART III Superseding 19th Rev. Sheet No. 17

Service Classification GP
General Service Primary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GP is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Single or three-phase service at primary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT): All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**

2) **Transmission Charge: $0.005257** per KWH for all KWH

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $52.56** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 5.48 per maximum KW during June through September
$ 5.09 per maximum KW during October through May
$ 1.86 per KW Minimum Charge

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.35 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.003358 per KWH for all KWH on-peak and off-peak

3) **Non-utility Generation Charge (Rider NGC):**
~~$0.000492~~ See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
~~$0.007013~~ See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Storm Recovery Charge (Rider SRC):**
See Rider SRC for rate per KWH for all KWH on-peak and off peak

8) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

9) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

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Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification GT
General Service Transmission

APPLICABLE TO USE OF SERVICE FOR: Service Classification GT is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Three-phase service at transmission voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT): All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**

2) **Transmission Charge: $0.004848** per KWH for all KWH
$0.001174 per KWH for all KWH High Tension Service

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $225.70** per month

1) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 3.52 per maximum KW
$ 0.94 per KW High Tension Service Credit
$ 2.34 per KW DOD Service Credit

KW Minimum Charge: (Demand Charge)
$ 1.07 per KW Minimum Charge
$ 0.70 per KW DOD Service Credit
$ 0.45 per KW Minimum Charge Credit

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.34 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.002595 per KWH for all KWH on-peak and off-peak
$0.000921 per KWH High Tension Service Credit
$0.001687 per KWH DOD Service Credit

3) **Non-utility Generation Charge (Rider NGC):**
~~$ 0.000457~~ See Rider NGC for rate per KWH for all KWH on-peak and off-peak – excluding High Tension Service
~~$ 0.000448~~ See Rider NGC for rate per KWH for all KWH on-peak and off-peak – High Tension Service

4) **Societal Benefits Charge (Rider SBC)**:
~~$0.007013~~ See Rider SBC for rate per KWH for all KWH on-peak and off-peak

JERSEY CENTRAL POWER & LIGHT COMPANY

20th Rev. Sheet No. 22
BPU No. 12 ELECTRIC - PART III **Superseding 19th Rev. Sheet No. 22**

Service Classification OL

Outdoor Lighting Service

RESTRICTION: Mercury vapor (MV) area lighting is no longer available for replacement and shall be removed from service when existing MV area lighting fails.

APPLICABLE TO USE OF SERVICE FOR: Service Classification OL is available for outdoor flood and area lighting service operating on a standard illumination schedule of 4200 hours per year, and installed on existing wood distribution poles where secondary facilities exist. This Service is not available for the lighting of public streets and highways. This Service is also not available where, in the Company's judgment, it may be objectionable to others, or where, having been installed, it is objectionable to others.

CHARACTER OF SERVICE: Sodium vapor (SV) flood lighting, high pressure sodium (HPS) and mercury vapor (MV) area lighting for limited period (dusk to dawn) at nominal 120 volts.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	HPS Area Lighting	MV Area Lighting	SV Flood Lighting
100	121	42	Not Available	**$ 2.46**	Not Available
175	211	74	Not Available	**$ 2.46**	Not Available
70	99	35	**$10.21**	Not Available	Not Available
100	137	48	**$10.21**	Not Available	Not Available
150	176	62	Not Available	Not Available	**$12.00**
250	293	103	Not Available	Not Available	**$12.60**
400	498	174	Not Available	Not Available	**$12.93**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): ~~$0.000492~~ See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): ~~$0.007013~~ See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

Service Classification SVL
Sodium Vapor Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification SVL is available for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

Sodium vapor conversions of mercury vapor or incandescent street lights shall be scheduled in accordance with the Company's SVL Conversion Program, and may be limited to no more than 5% of the lamps served under this Service Classification at the end of the previous year.

CHARACTER OF SERVICE: Sodium vapor lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
50	60	21	**$ 5.96**	**$ 1.67**	**$ 0.81**
70	85	30	**$ 5.96**	**$ 1.67**	**$ 0.81**
100	121	42	**$ 5.96**	**$ 1.67**	**$ 0.81**
150	176	62	**$ 5.96**	**$ 1.67**	**$ 0.81**
250	293	103	**$ 7.05**	**$ 1.67**	**$ 0.81**
400	498	174	**$ 7.05**	**$ 1.67**	**$ 0.81**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): ~~$0.000492~~ See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): ~~$0.007013~~ See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

JERSEY CENTRAL POWER & LIGHT COMPANY

20th Rev. Sheet No. 27

BPU No. 12 ELECTRIC - PART III Superseding 19th Rev. Sheet No. 27

Service Classification MVL
Mercury Vapor Street Lighting Service

RESTRICTION: Service Classification MVL is in process of elimination and is withdrawn except for the installations of customers receiving Service hereunder on July 21, 1982, and only for the specific premises and class of service of such customer served hereunder on such date.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents. At the option of the Company, Service may also be provided for lighting service on streets, roads or parking areas on municipal or private property where supplied directly from the Company's facilities when such Service is contracted for by the owner or agency operating such property.

CHARACTER OF SERVICE: Mercury vapor lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All charges include Sale and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
100	121	42	**$ 4.16**	**$ 1.58**	**$ 0.80**
175	211	74	**$ 4.16**	**$ 1.58**	**$ 0.80**
250	295	103	**$ 4.16**	**$ 1.58**	**$ 0.80**
400	468	164	**$ 4.51**	**$ 1.58**	**$ 0.80**
700	803	281	**$ 5.46**	**$ 1.58**	**$ 0.80**
1000	1135	397	**$ 5.46**	**$ 1.58**	**$ 0.80**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):
1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):
1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): ~~$0.000492~~ See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): ~~$0.007013~~ See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

Issued: **Effective:**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. and dated

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 12 ELECTRIC - PART III

20th Rev. Sheet No. 30
Superseding 19th Rev. Sheet No. 30

Service Classification ISL
Incandescent Street Lighting Service

RESTRICTION: Service Classification ISL is in process of elimination and is withdrawn except for the installations of customers currently receiving Service, and except for fire alarm and police box lamps provided under Special Provision (c). The obsolescence of this Service Classification's facilities further dictates that Service be discontinued to any installation that requires the replacement of a fixture, bracket or street light pole.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets or roads where required by city, town, county, State or other principal or public agency or by an incorporated association of local residents.

CHARACTER OF SERVICE: Incandescent lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All Charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings Lamp Wattage	Billing Month KWH *	Company Fixture	Customer Fixture
105	37	**$ 1.76**	**$ 0.80**
205	72	**$ 1.76**	**$ 0.80**
327	114	**$ 1.76**	**$ 0.80**
448	157	**$ 1.76**	**$ 0.80**
690	242	**$ 1.76**	**$ 0.80**
860	301	**$ 1.76**	**$ 0.80**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): ~~$0.000492~~ See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): ~~$0.007013~~ See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Storm Recovery Charge (Rider SRC): See Rider SRC for rate** per KWH
6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

Service Classification LED
LED Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification LED is available for installation of 12 or more LED (light emitting diode) fixtures per request for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

LED conversions of sodium vapor, mercury vapor or incandescent street lights shall be scheduled at the Company's reasonable discretion.

CHARACTER OF SERVICE: LED lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Lamp Wattage	Type	Lumens	Billing Month KWH*	Company Fixture
50	Cobra Head	4000	18	**$ 6.37**
90	Cobra Head	7000	32	**$ 7.04**
130	Cobra Head	11500	46	**$ 8.38**
260	Cobra Head	24000	91	**$ 10.83**
50	Acorn	2500	18	**$ 15.25**
90	Acorn	5000	32	**$ 15.94**
50	Colonial	2500	18	**$ 8.72**
90	Colonial	5000	32	**$ 12.37**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the lamp wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

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6) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
7) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH

TERM OF CONTRACT: Ten years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than ten years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

EXHIBIT JC-14

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

John J. Spanos

Re: Depreciation Study and Proposed Depreciation Accrual Rate

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. By whom and in what capacity are you employed?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC as President.

Q. Please describe your education and business experience.

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

I have been associated with Gannett Fleming since college graduation in 1986. Gannett Fleming Valuation and Rate Consultants, LLC provides depreciation consulting services to utility companies in the United States and Canada. As President, I am responsible for conducting depreciation, valuation and original cost studies, determining service life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to clients, and supporting such rates before state and federal regulatory agencies.

Q. Please state your qualifications.

A. I have over 33 years of depreciation experience, which includes giving expert testimony in over 320 cases before 40 regulatory commissions, including this Commission. In addition to cases where I have submitted testimony, I have supervised over 600 other depreciation or valuation assignments. Please refer to Appendix A for my qualifications statement, which includes further information with respect to my work history, case experience and leadership in the Society of Depreciation Professionals.

Q. What is the purpose of your prefiled direct testimony in this proceeding?

A. I was asked to recommend depreciation rates for Jersey Central Power & Light Company's ("JCP&L" or the "Company") Electric Plant Accounts. I am sponsoring Exhibit JC-14, Schedule JJS-1 stating the results of my depreciation analysis related to Jersey Central Power & Light's electric plant as of March 31, 2019 (the Depreciation Study or Study). The recommended depreciation rates for JCP&L are set forth on pages V-4 and V-5.

Q. Would you please summarize your testimony?

A. My testimony will explain the methods and procedures of the Depreciation Study and sets forth the annual depreciation rates as of March 31, 2019 for intangible, distribution and general plant. Exhibit JC-14, Schedule JJS-1 sets forth detailed methods, procedures and results of the Depreciation Study as of March 31, 2019. My Depreciation Study will be explained in Part II of my testimony.

Q. Please summarize the principal conclusion of your depreciation study.

A. The principal conclusion of the Study is that JCP&L's current depreciation rates need to be updated based on the more appropriate life parameters upon which the rates are based. I have proposed updated depreciation accrual rates by intangible, distribution and general plant account in the Depreciation Study. Generally, my recommended rates are based on a combination of my review of historic data and JCP&L's operating maintenance practices, as well as the application of informed engineering judgment. Exhibit JC-14, Schedule JJS-2 sets forth a comparison of the proposed rates with the current rates as of March 31, 2019. As of March 31, 2019, the recommended depreciation rates increase depreciation expense by $33.1 million when compared to the depreciation expense that results from the currently approved depreciation rates. In this case, JCP&L is requesting to include a net salvage normalization component in its depreciation expense, based on its actual Cost of Removal experience over the most recent 5-years. Applying the net normalization method to calculate a net salvage component in depreciation expense of $23,030,504, which represents an increase to test year expense of $7,788,834 (compared to the $15,241,670 of net salvage in current base rates) (*See* Testimony of Carol A. Pittavino, Exhibit JC-4, Adjustment 14).

The most significant contributor to the depreciation expense is an increase of $10.4 million related to FERC Account 365: Overhead Conductor and Devices. My review of JCP&L's experience since 2011 indicates significant retirements in Account 365, which would be expected, given the storm damage that JCP&L has experienced (*See* Testimony of Dennis Pavagadhi, Exhibit JC-7).

Q. Please explain how the practice for net salvage that has been used in New Jersey impacts the depreciation accruals that result from the Depreciation Study.

A. The current practice in New Jersey for the recovery of net salvage costs is different from the practice in most jurisdictions, in that net salvage is not recovered over the lives of the Company's assets while they are in service. Rather, a net salvage normalization has typically been established in which net salvage costs are recovered after the related assets are retired. This approach is referred to as the "net salvage normalization method," and contrasts with the traditional method of accruing for net salvage over the life of the Company's assets (which is referred to as the "traditional method" or "traditional accrual method"). One result of this practice is that, if a company spends more money on cost of removal, there will be a resulting increase in depreciation expense in the next depreciation study in order to recover these historical net salvage costs. Additionally, JCP&L has not been incorporating a net salvage component in their rates, thus, most of the increase in the Depreciation Study is the result of the need to recover removal costs that were incurred in recent years.

Q. Please describe the contents of your report.

A. The Study is presented in eight parts:

- Part I, Introduction, presents the scope and basis for the Depreciation Study;
- Part II, Estimation of Survivor Curves, explains the process of estimating survivor curves and the retirement rate method of life analysis;
- Part III, Service Life Considerations, discusses factors and the informed judgment involved with the estimation of service life;
- Part IV, Net Salvage Considerations, discusses the process of determining the net salvage normalization component;
- Part V, Calculation of Annual and Accrued Depreciation, explains the method, procedure and technique used in the calculation of annual depreciation expense and the theoretical reserve;
- Part VI, Results of Study, sets forth the service life estimates, net salvage normalization expense, and annual depreciation rates and accruals for each depreciable group. This section also includes a description of the detailed tabulations supporting the Depreciation Study;
- Part VII, Service Life Statistics, sets forth the survivor curve estimates and original life tables for each plant account and subaccount; and
- Part VIII, Detailed Depreciation Calculations, sets forth the calculation of average remaining life for each property group.

The table on pages VI-4 and VI-5 of the report presents the results of the Study, including: (1) the estimated survivor curve; (2) the original cost as of March 31, 2019;

(3) the book reserve; and (4) the proposed annual depreciation accrual and rate for each account or subaccount. The section beginning on page VII-2 of the report presents the results of the retirement rate analyses, which set forth the historical bases for the service life estimates. The section beginning on page VIII-2 of Exhibit JC-14, Schedule JJS-1 presents the depreciation calculations related to surviving original cost as of March 31, 2019.

II. METHODS USED IN DEPRECIATION STUDY

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operations and against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation and valuation?

A. Yes.

Q. Please identify the depreciation method that you used.

A. I used the straight line remaining life method of depreciation, with the average service life procedure. This is the method which JCP&L used in its most recent rate proceeding. This method of depreciation aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit or group of assets in a systematic and rational manner.

For General Plant Accounts 391.10, 391.15, 391.20. 391.25, 393, 394, 395, 397, and 398, I used the straight line remaining life method of amortization. The account numbers identified throughout my testimony represent those in effect as of March 31, 2019. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage. These amounts relate to the portion related to the distribution entity.

Q. What are your recommended annual depreciation accrual rates for JCP&L?

A. My recommended annual depreciation accrual rates as of March 31, 2019 for JCP&L are set forth on pages VI-4 and VI-5 of the Depreciation Study.

Q. How did you determine the recommended annual depreciation accrual rates?

A. I did this in two phases. In the first phase, I estimated the service life characteristics for each depreciable group (*i.e.,* each plant account or subaccount identified as having similar characteristics). I also determined the most appropriate level of net salvage normalization by account. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life estimates determined in the first phase.

Q. Please describe the first phase of the Depreciation Study, in which you estimated the service life characteristics for each depreciable group.

A. The service life study consisted of compiling historic data from records related to JCP&L's plant; analyzing these data to obtain historic trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to form judgments of average service life characteristics.

Q. What historic data did you analyze for the purpose of estimating service life characteristics?

A. I analyzed the Company's accounting entries that record plant transactions primarily for the period, 1939 through 2018. The transactions included additions, retirements, transfers and the related balances. The Company records also included surviving dollar value by year installed for each plant account as of March 31, 2019.

Q. What method did you use to analyze this service life data?

A. I used the retirement rate method for all accounts. This is the most appropriate method when aged retirement data are available, because it determines the average rates of retirement actually experienced by the Company during the period covered by the study.

Q. Would you explain how you used the retirement rate method to analyze JCP&L's service life data?

A. I applied the retirement rate method to each different group of property in the study. For each property group, I used the retirement rate method to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa-type survivor curves were used to perform these interpretations.

Q. What is an "Iowa-type survivor curve" and how did you use such curves to estimate the service life characteristics for each property group?

A. Iowa-type curves are a widely used group of generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State University College of Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. As I will explain, the use of truncated curves is appropriate to reflect retirements of plant components that may not be fully depreciated at the time a plant is retired.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 37-R1 indicates an average service life of thirty-seven years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a low height, 1, for the mode (possible modes for R type curves range from 1 to 5) and the results incorporated in the estimation of the facility's life span.

Q. Should the estimation of survivor curves be based solely on the results of statistical life analyses?

A. No. Because depreciation requires the estimation of future service lives for assets currently in service, and because the historical database only allows for the analysis of a portion of the full service lives of each group of assets, informed judgment is necessary to determine the most reasonable survivor curve estimate. Judgment must be used not only to incorporate information external to the statistical analyses, but also to properly interpret the historical data as part of the curve fitting process. Authoritative depreciation texts support that judgment is necessary in the estimation of depreciation, and that reliance only on statistical results can, and does, produce unreasonable results.

Q. Have you physically observed JCP&L's assets as part of your depreciation studies?

A. Yes. I made a field review of JCP&L's property in September 2019 to update my analyses on a representative portion of plant. A prior field visit was conducted in May 2013. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. For example, I had detailed discussions with Company personnel regarding the different forces of retirement for some of their regions. This knowledge as well as information from other discussions with management was incorporated into my statistical analyses.

Q. How did your experience in development of other depreciation studies affect your work in this case?

A. Because I customarily conduct field reviews for my depreciation studies, I have had the opportunity to visit scores of similar facilities and meet with operations personnel at other companies. The knowledge accumulated from those visits and meetings provide me useful information that I can draw on to confirm or challenge my numerical analyses concerning asset condition and remaining life estimates.

Q. Would you please explain the concept of "net salvage"?

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage.

Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage.

Inasmuch as depreciation expense is the loss in service value of an asset during a defined period, *e.g.,* one year, it must include a ratable portion of both the original cost and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value. For example, the full recovery of the service value of a $1,000 distribution pole will include not only the $1,000 of original cost, but also, on average, $450 to remove the pole at the end of its life and $50 in salvage value. In this example, the net salvage component is negative $400 ($50 - $450), and the net salvage percent is negative 40% (($50 - $450)/$1,000).

Q. Have you included a net salvage percentage as part of the depreciation accrual rates in the Study?

A. Yes. The recommended depreciation rates provided in Table 1 of the Depreciation Study incorporate the net salvage normalization method. The net salvage normalization method is only designed to recover net salvage costs, based on a historical 5-year average experience, and does not recover net salvage costs over the period of time the related assets will be in service.

Based on the currently accepted practice of the New Jersey Board of Public Utilities, the Company's proposal in this case uses the depreciation rates shown on Table 1 of the Study that incorporate the net salvage normalization method. For ratemaking purposes, while the net salvage normalization method is an improvement over expensing net salvage costs (*i.e.*, Cost of Removal), I do not believe the net salvage normalization method is the most reasonable method for recovery of net salvage costs. Most appropriately, depreciation expense would include a ratable portion of both the original cost and the net salvage over the life of the assets providing service.

Q. Please describe how you calculated the net salvage normalization amounts used in the depreciation rates provided in Table 1 of the Study.

A. For purposes of the depreciation rates based on the net salvage normalization method, the net salvage normalization amounts for each account were calculated based on historical data for the period 2014 through 2018. In the historical analyses cost of removal and gross salvage amounts were recorded by account within the 5-year period, 2014 – 2018, and set forth on Table 2, page VI-_ of the depreciation study. Years prior to 2014 were reviewed to understand the trends of cost of removal and gross salvage. The most distinct trend from prior years is that cost of removal has increased significantly. Reasons for the increase in recorded costs of removal include the increased volume of work associated with reliability improvements, as well as the costs of work to replace assets that were damaged as a result of storms.

Once these data were assembled, I calculated the five-year average of the 2014 - 2018 experienced costs and incorporated that average as the annual net salvage expense reflected in the depreciation rates based on the net salvage normalization method.

Q. Please describe the process that you used in the Depreciation Study to calculate composite remaining lives and annual depreciation accrual rates.

A. After I estimated the service life characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group based on the straight line remaining life method, using remaining lives weighted consistent with the average service life procedure. The annual depreciation accrual rates were developed as of March 31, 2019.

Q. Please describe the straight line remaining life method of depreciation.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. Please describe the average service life procedure for calculating remaining life accrual rates.

A. The average service life procedure defines the group for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and this rate is applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for each vintage. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. Then, the sum of the future book accruals is divided by the sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate.

Q. You stated earlier that for certain general plant accounts you used amortization accounting to calculate proposed deprecation rates. Could you please describe amortization accounting?

A. Yes. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, amortization accounting is more appropriate than depreciation accounting for accounts with a large number of units, but small asset values. This is true because in order to properly reflect plant in service, depreciation accounting requires periodic inventories, which is a difficult and burdensome task for these assets (*i.e.,* large number of units, but small values). Consequently, a more accurate method is to record retirements when a vintage is fully amortized rather than as the units are removed from service. As a result, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period which represents an anticipated life which the asset will render full benefit. For example, in amortization accounting, assets that have a 20-year amortization period will be fully recovered after 20 years of service and taken off the Company's books, but not necessarily removed from service. In contrast, assets that are taken out of service before 15 years remain on the books until the amortization period for that vintage has expired.

Q. Can you explain why you recommend amortization accounting?

A. Amortization accounting has been implemented by almost all utility companies across the United States and Canada over the past 20-25 years. I have continued to present this methodology in the depreciation study in order to smooth the annual depreciation accrual rate over time for the specific asset classes described in general plant as well as to improve record keeping practices for a large number of assets that have a small utility plant in service value.

Q. Is amortization accounting currently used for certain general plant accounts for JCP&L?

A. Yes. Amortization accounting has been implemented in JCP&L's previous depreciation study.

Q. For which plant accounts is amortization accounting being utilized?

A. Amortization accounting is only appropriate for certain General Plant accounts. These are accounts 391.10, 391.15, 391.20. 391.25, 393, 394, 395, 397, and 398 for electric plant. They represent slightly more than two percent of depreciable plant in this study.

Q. Are there any specific adjustments made to accounts for which amortization accounting is used?

A. Yes. The preference for amortization accounting is that the rate applied to each plant account is equal to one divided by the amortization period. Because assets are retired once they reach the end of the amortization period, this rate can be consistently applied going forward.

However, when amortization accounting is properly implemented, there is typically a difference between the book reserve and the accumulated depreciation amount that would result in a calculated remaining life rate that is equal to one divided by the amortization period. Additionally, assets older than the amortization period need to be retired when amortization accounting is implemented. For these reasons, an adjustment may be made in order to amortize any accumulated depreciation differences over a shorter period of time. I have recommended to make such an adjustment in the Depreciation Study. Because depreciation studies are conducted periodically, the intent is that using a five-year period, which is a typical time between depreciation studies, will mean that similar adjustments will not be needed in future depreciation studies. A slight modification to a 4-year period is recommended in order to be consistent with the practices of the related transmission company. Therefore, the reserve amortization will be initiated in January 2021 and end in 2024.

Q. Please use an example to illustrate the development of the annual depreciation accrual rate for a particular group of property in your depreciation study.

A. I will use Account 365, Overhead Conductors and Devices, as an example because it is one of the largest depreciable groups and represents 18% of depreciable plant for JCP&L.

I used the retirement rate method to analyze the survivor characteristics of this property group. I compiled aged plant accounting data from 1934 through 2018 and analyzed the data for periods that best represent the overall service life of the property. I present the life tables for the 1934-2018 and 1959-2018 experience bands on pages VII-33 through VII-38 of Exhibit JC-14, Schedule JJS-1. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-33 shows $11,033,415 retired during age interval 0.5-1.5 with $1,068,583,424 exposed to retirement at the beginning of the interval. Consequently, the retirement ratio is 0.0103 ($11,033,415/$1,068,583,424) and the surviving ratio is 0.9897 (1-0.0103). The percent surviving at age 0.5 of 0.9978 percent is multiplied by the survivor ratio of 98.97 to derive the percent surviving at age 1.5 of 98.75 percent. This process continues for the remaining age intervals for which plant was exposed to retirement during the period 1934-2018. The resultant life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 37-R1 on page VII-32.

I present the net salvage normalization amount on page VI-6. This amount of negative $21,734,057, which is the five-year average of net salvage costs for the period, 2014-2018, is brought forward to column 9 of Table 1 on pages VI-4 and VI-5 of the Depreciation Study.

I provide my calculation of the annual depreciation related to original cost of Account 365, Overhead Conductors and Devices, at March 31, 2019, on pages VIII-15 and VIII-16 Exhibit JC-14, Schedule JJS-1. The calculation is based on the 37-R1 survivor curve, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to Table 1 on page VI-4 for the annual depreciation amount by account.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Appendix A

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013 and February 2018.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December, 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso

Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of

Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire and Newtown Artesian Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana

Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.		Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	09-	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC		Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC		Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC		Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Commission	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC		Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-19 / UG-19	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	NJ BPU	Docket No. ER20-___-000	Jersey Central Power & Light Company	Depreciation

Schedule JJS-1

JERSEY CENTRAL POWER & LIGHT COMPANY

MORRISTOWN, NEW JERSEY

2019 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF MARCH 31, 2019

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***

Schedule JJS-1

JERSEY CENTRAL POWER & LIGHT COMPANY

Morristown, New Jersey

2019 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF MARCH 31, 2019

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Harrisburg, Pennsylvania

Schedule JJS-1

Gannett Fleming

Excellence Delivered ***As Promised***

February 7, 2020

Jersey Central Power & Light Company
300 Madison Avenue
Morristown, NJ 07960

Attention: Mr. Mark A. Mader
Director, Rates and Regulatory Affairs

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric intangible, distribution and general plant of Jersey Central Power & Light Company as of March 31, 2019. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the life and net salvage estimates and the detailed tabulations of annual depreciation.

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Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John J. Spanos

JOHN J. SPANOS
President

JJS:mle

065806.000

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JERSEY CENTRAL POWER & LIGHT COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Jersey Central Power & Light Company's ("JCP&L" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the electric intangible, distribution and general plant as of March 31, 2019. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life, survivor curve and net salvage normalization component for each depreciable group of assets.

JCP&L's accounting policy has not changed since the last depreciation study related to the distribution plant. However, there have been some changes in life parameters and net salvage recovery methods which have caused the proposed remaining lives for some accounts to change from those previously approved.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric distribution plant and the allocated portion of intangible and general plant in service as of March 31, 2019 as summarized by Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of $144.4 million when applied to the related depreciable electric distribution plant balances as of March 31, 2019.

SUMMARY OF ORIGINAL COST, PROPOSED ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST AS OF MARCH 31, 2019	ACCRUAL RATE	ACCRUAL AMOUNT
Intangible Plant	$ 112,020,272.98	7.32	$ 8,201,486
Distribution Plant	4,800,547,135.04	2.66	127,501,945
General Plant	216,809,501.93	2.78	6,034,225
General Plant Reserve Amortization	-	-	2,637,161
Total Depreciable Plant	**$5,129,376,909.95**	**2.81**	**$144,374,817**

PART I. INTRODUCTION

JERSEY CENTRAL POWER & LIGHT COMPANY
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Jersey Central Power & Light Company ("Company"), as applied to electric intangible, distribution and general plant in service as of March 31, 2019. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to electric distribution and general plant in service as of March 31, 2019.

The service life estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2018, the net salvage normalization of historical plant retirement data recorded for the most recent five years, 2014-2018; a review of Company practice and outlook as they relate to plant operation and retirement, and consideration of current practice in the electric industry, including knowledge of service lives and net salvage estimates used for other electric companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life study. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents the judgment utilized for the net salvage normalization component. Part V, Calculation of Annual and Accrued

Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents a summary by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates and Part VIII, Detailed Depreciation Calculations presents the detailed tabulations of annual depreciation.

BASIS OF THE STUDY

<u>Depreciation</u>

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

For most accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. For certain General Plant Accounts, the annual depreciation was based on amortization accounting. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America, including the Federal Energy Regulatory Commission (FERC). Gannett Fleming recommends its continued use.

Service Life Estimates and Net Salvage Component

The service life estimates used in the depreciation calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility property. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical and forecasted data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The net salvage normalization component by account incorporated a review of experienced costs of removal and salvage for the most recent five years related to plant retirements.

An understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel. The supplemental information obtained in this manner was considered in the interpretation and extrapolation of the statistical analyses.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves,

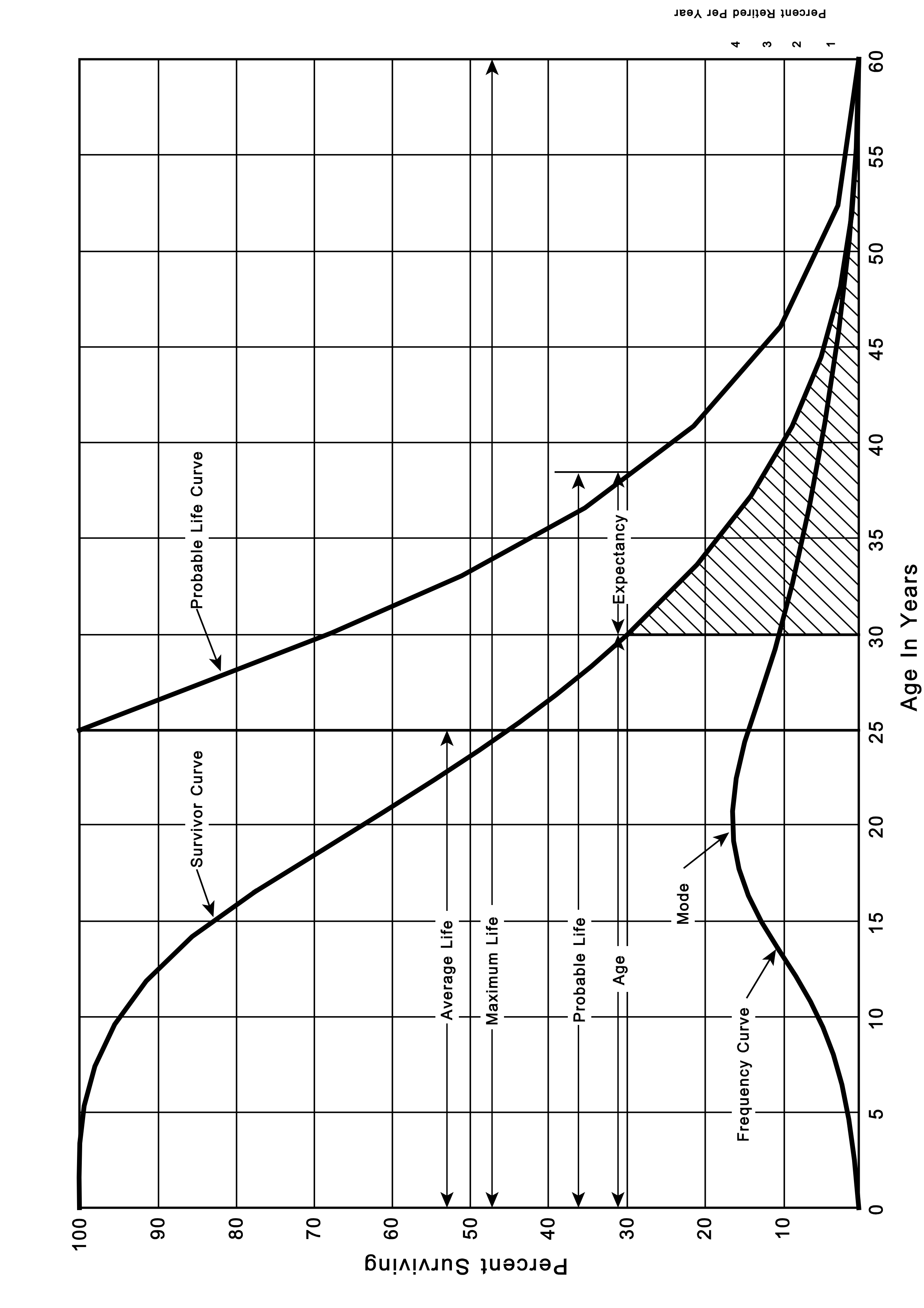

Figure 1. A Typical Survivor Curve and Derived Curves

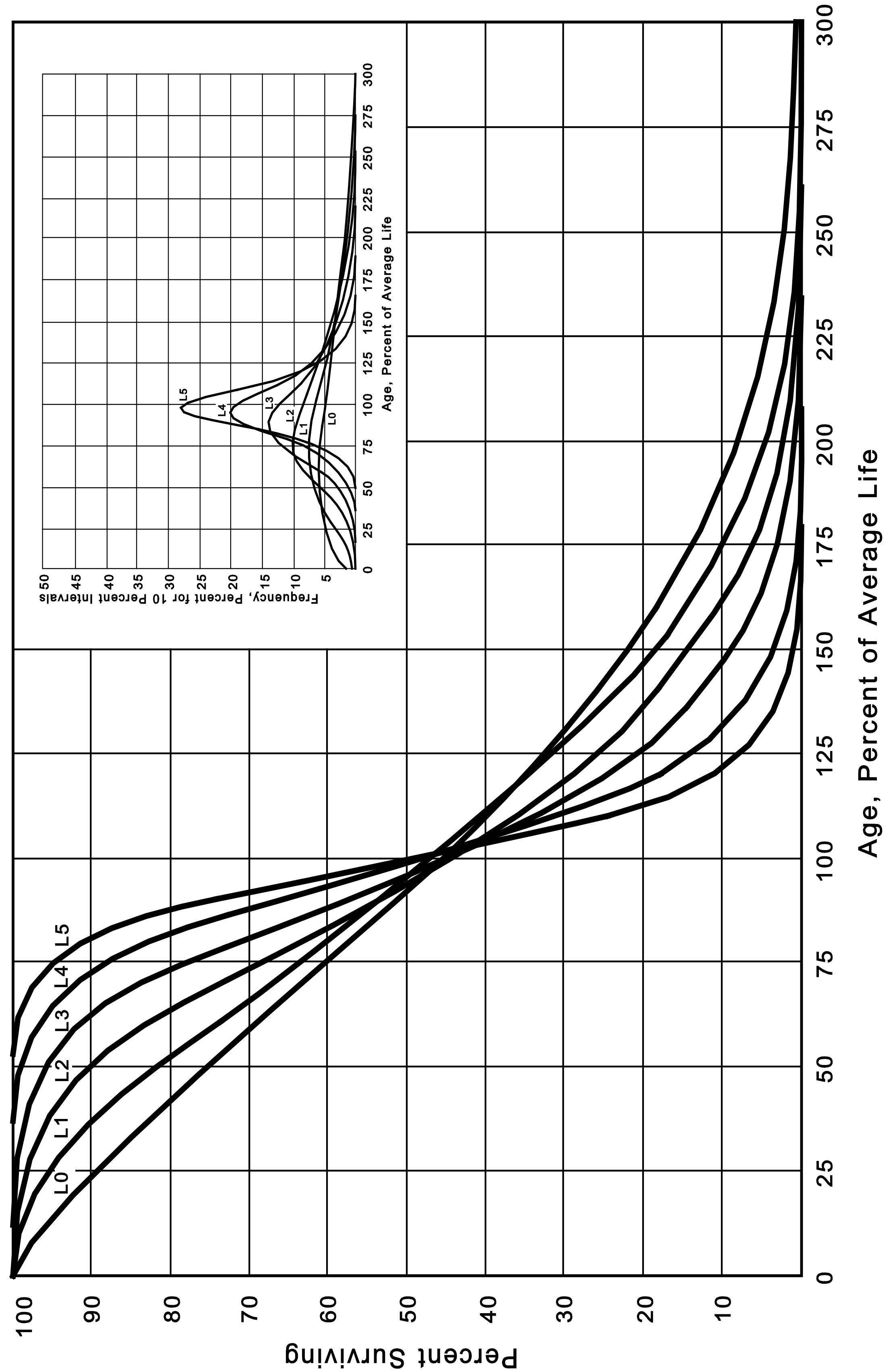

Figure 2. Left Modal or "L" Iowa Type Survivor Curves

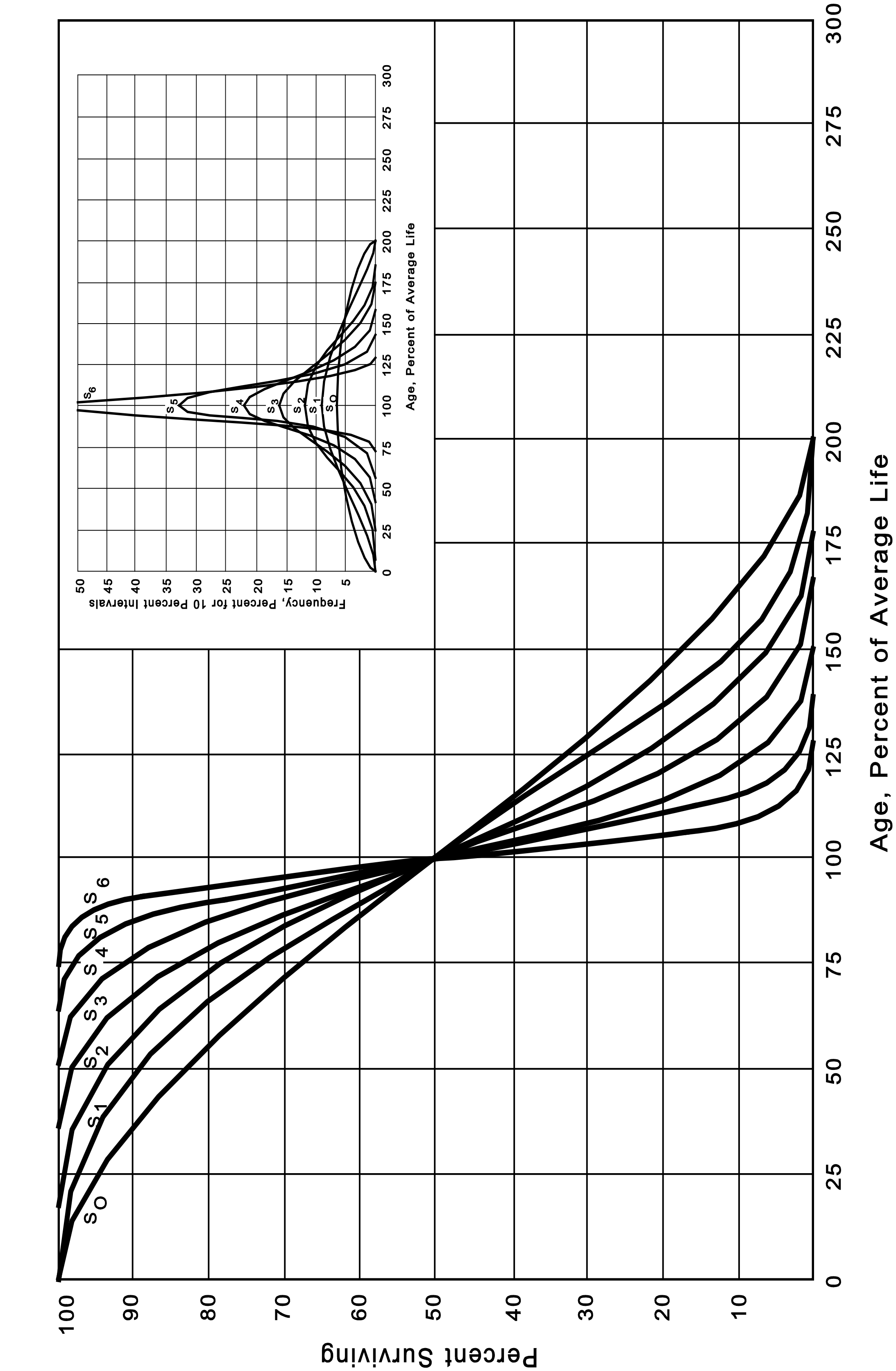

Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

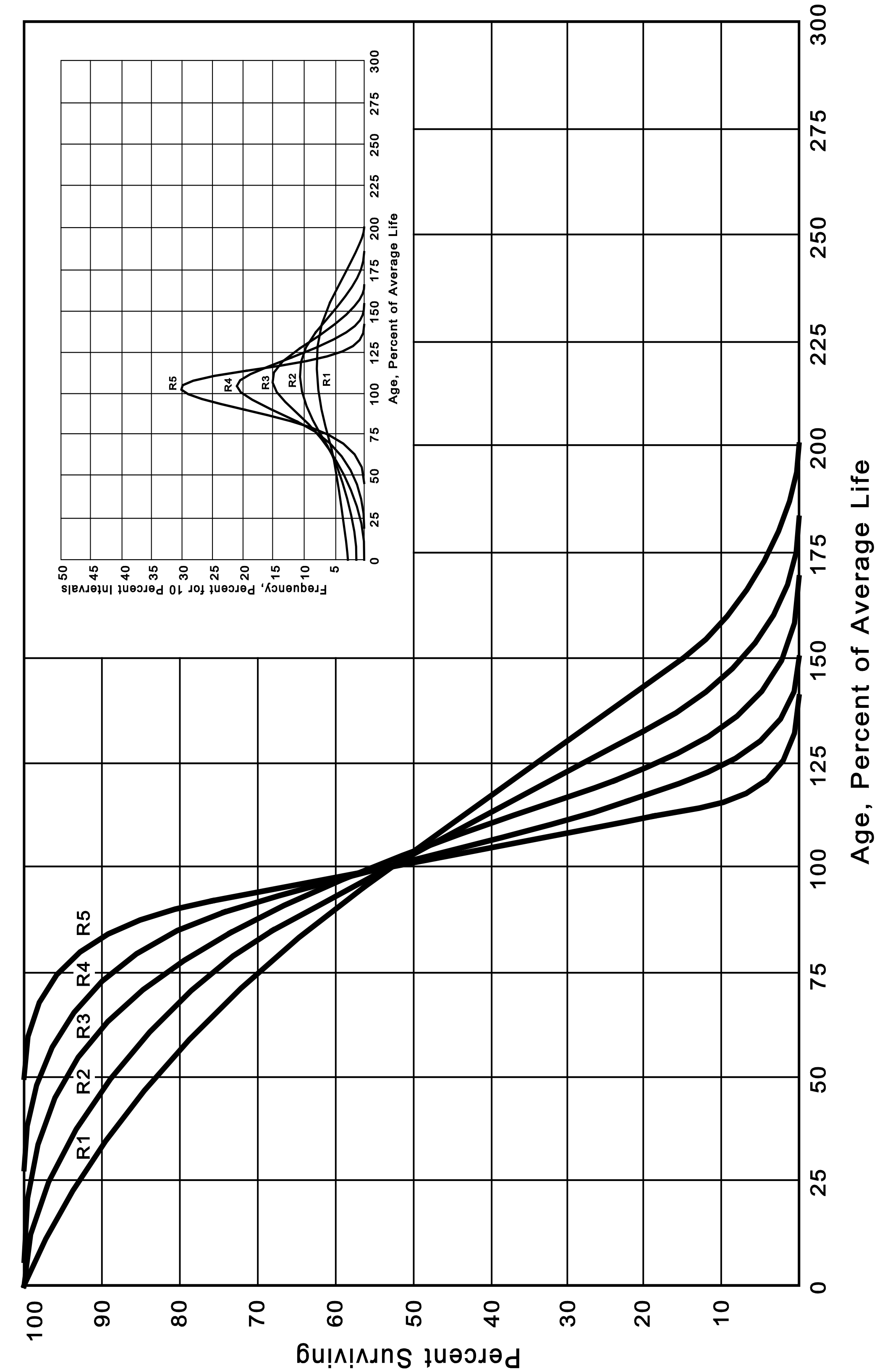

Figure 4. Right Modal or "R" Iowa Type Survivor Curves

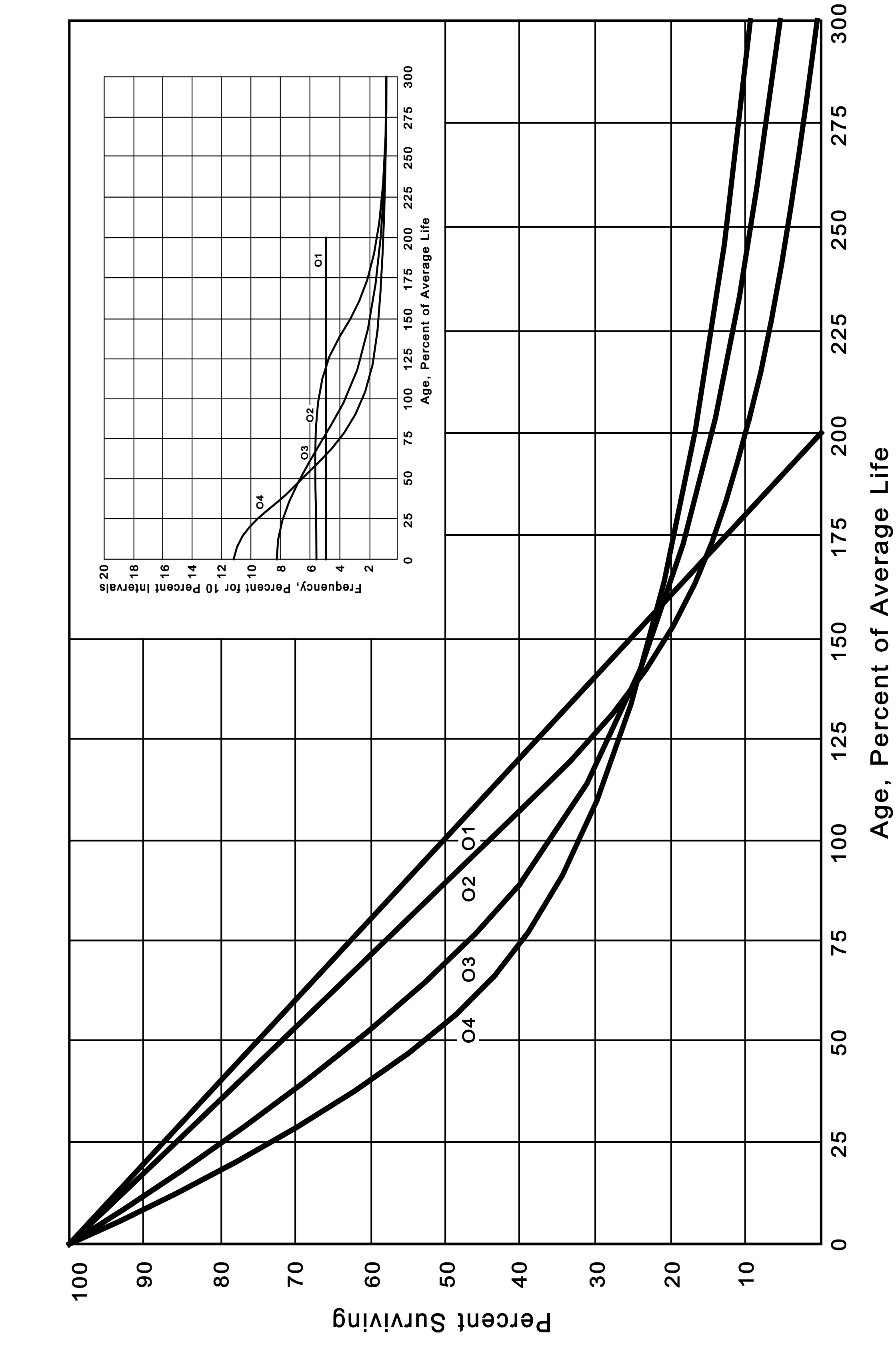

Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125. These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes

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[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College Engineering Experiment Station, Bulletin 125. 1935..

[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

<u>Schedules of Annual Transactions in Plant Records</u>

The property group used to illustrate the retirement rate method is observed for the experience band 2009-2018 during which there were placements during the years 2004-2018. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2004 were retired in 2009. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2009 retirements of 2004 installations and ending with the 2018 retirements of the 2013 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018 | Placement Band 2004-2018

Year Placed	Retirements, Thousands of Dollars During Year 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total During Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2004	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2005	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2006	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2007	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2008	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2009	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2010		5	11	12	13	14	15	16	18	20	113	7½-8½
2011			6	12	13	15	16	17	19	19	124	6½-7½
2012				6	13	15	16	17	19	19	131	5½-6½
2013					7	14	16	17	19	20	143	4½-5½
2014						8	18	20	22	23	146	3½-4½
2015							9	20	22	25	150	2½-3½
2016								11	23	25	151	1½-2½
2017									11	24	153	½-1½
2018										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018 | Placement Band 2004-2018

	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
Year Placed (1)	2009 (2)	2010 (3)	2011 (4)	2012 (5)	2013 (6)	2014 (7)	2015 (8)	2016 (9)	2017 (10)	2018 (11)	Total During Age Interval (12)	Age Interval (13)
2004	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2005	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2006	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2007	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2008	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2009	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2010		-	-	-	-	-	-	-	-	-	6	7½-8½
2011			-	-	-	-	-	-	-	-	-	6½-7½
2012				-	-	-	-	(12)[b]	-	-	-	5½-6½
2013					-	-	-	-	22[a]	-	-	4½-5½
2014						-	-	(19)[b]	-	-	10	3½-4½
2015							-	-	-	-	-	2½-3½
2016								-	-	(102)[c]	(121)	1½-2½
2017									-	-	-	½-1½
2018											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2009 through 2018 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or additions are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2014 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018 | Placement Band 2004-2018

Year	Exposures, Thousands of Dollars										Total at	Age
	Annual Survivors at the Beginning of the Year										Beginning of	
Placed	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Age Interval	Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2004	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2005	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2006	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2007	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2008	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2009	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2010		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2011			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2012				580[a]	574	561	546	530	501	482	3,057	5½-6½
2013					660[a]	653	639	623	628	609	3,789	4½-5½
2014						750[a]	742	724	685	663	4,332	3½-4½
2015							850[a]	841	821	799	4,955	2½-3½
2016								960[a]	949	926	5,719	1½-2½
2017									1,080[a]	1,069	6,579	½-1½
2018										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2009-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16**,** is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2009-2018 | Placement Band 2004-2018

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
14.5					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

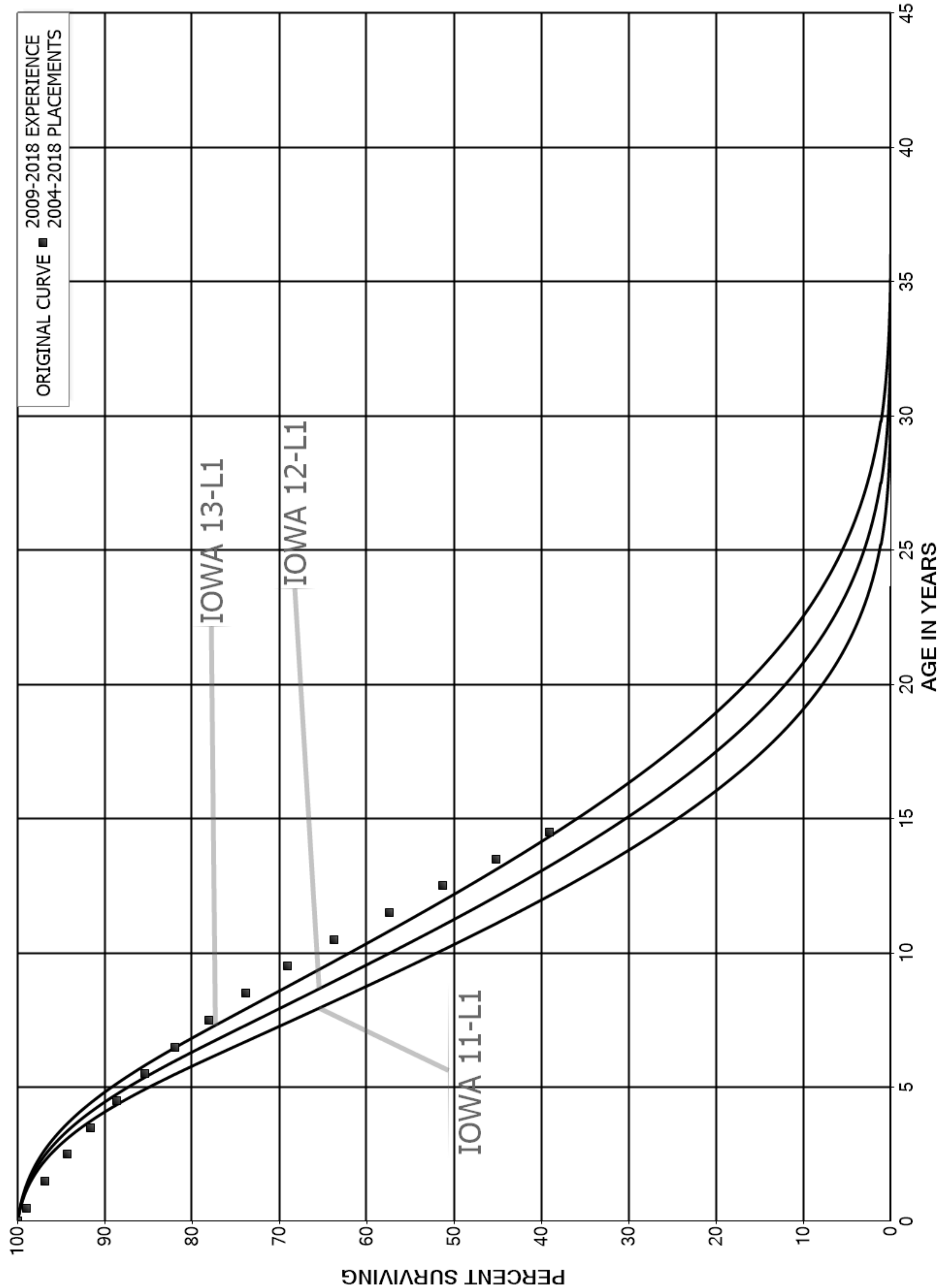


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

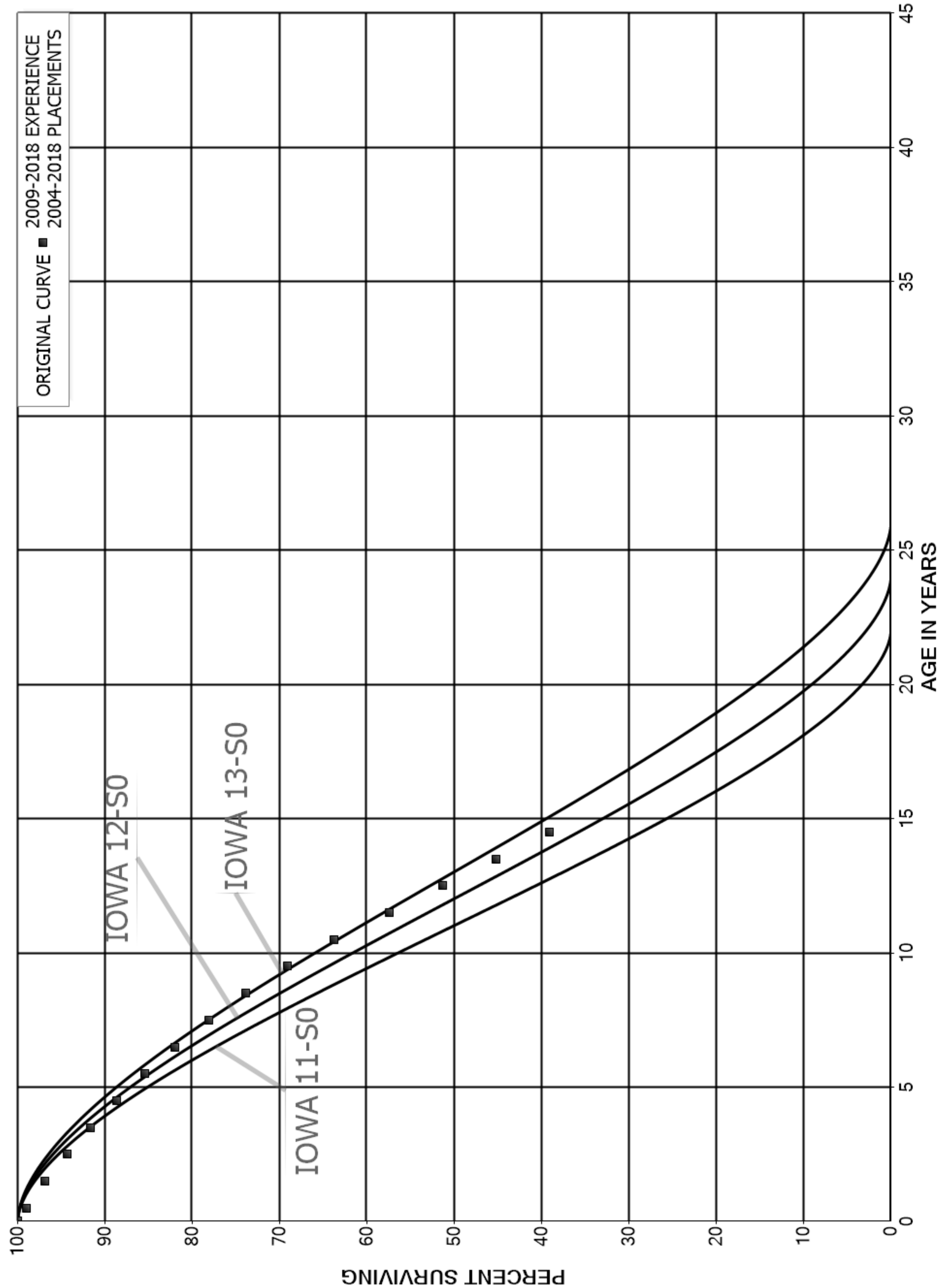


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

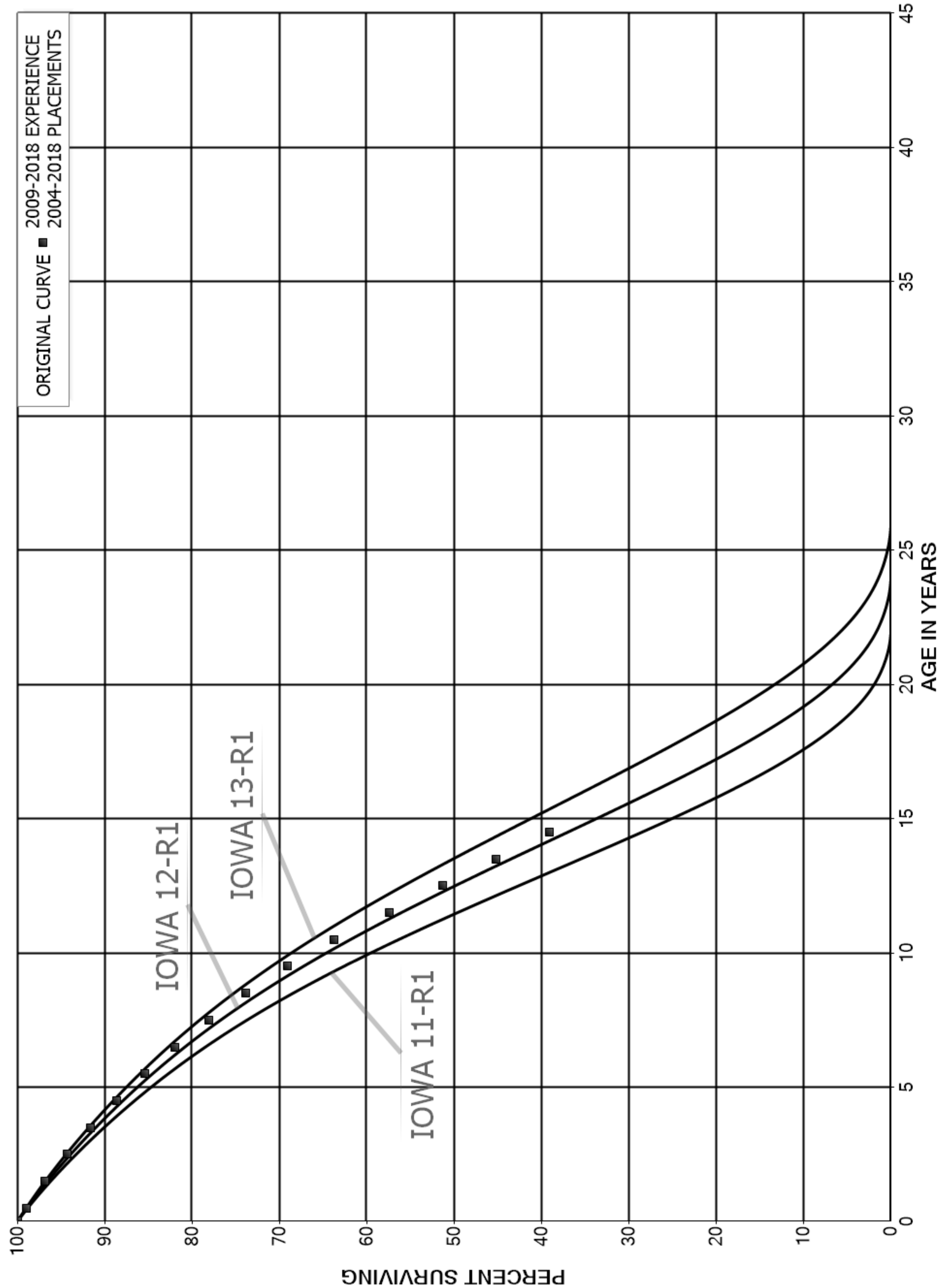
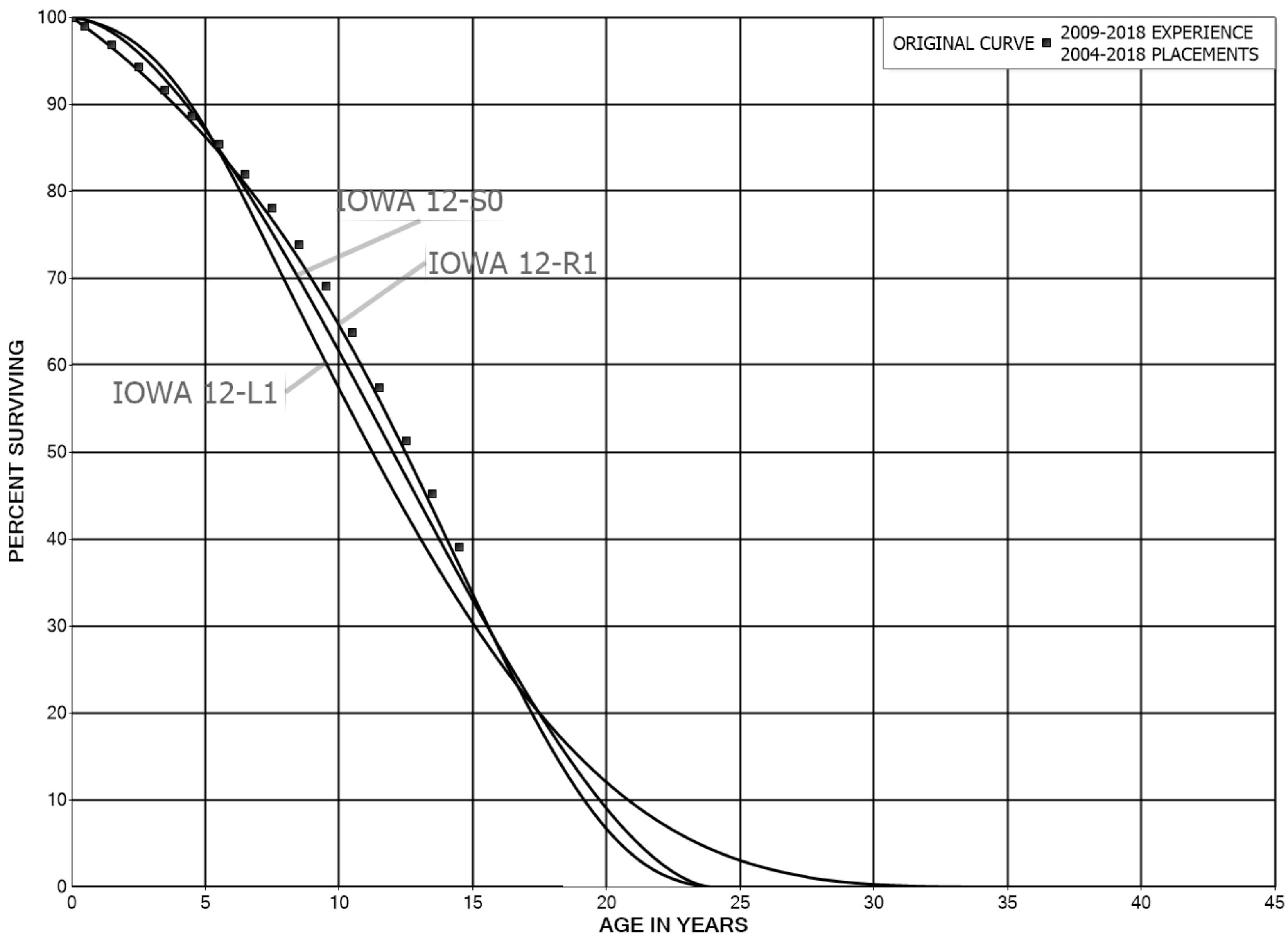


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

Field Trips

In order to be familiar with the operation of the Company and to observe representative portions of the plant, a field trip was conducted. A sampling of various types of facilities was selected to best represent the various assets in service. Aside from the obtained knowledge of age, type and condition of each group of assets that were visited, a discussion with key operational personnel as to the outlook of each asset group was conducted. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements was obtained during each trip. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The plant facilities visited during the most recent trips are as follows:

<u>September 26, 2019</u>
Morristown Legion Place Service Center
Alderney Substation
East Dover Substation
Mount Fern Substation
Morristown Substation

<u>May 2, 2013</u>
Traynor Substation
Summit Line Shop
East Hanover Shop
Whippany Substation
Okner Parkway Substation
Florham Park Substation
Morris Plains Substation

Service Life Analysis

The service life estimates were based on judgment, which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric utility companies.

For 13 of the plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. These accounts represent 83 percent of depreciable plant. Generally, the information external to the statistics led to no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

DISTRIBUTION PLANT

362.00	Station Equipment
364.00	Poles, Towers and Fixtures
365.00	Overhead Conductors and Devices
365.10	Overhead Conductors and Devices - Clearing
367.00	Underground Conductors and Devices
368.00	Line Transformers
370.00	Meters
371.00	Installations on Customers' Premises
373.00	Street Lighting and Signal Systems

GENERAL PLANT

390.10	Structures and Improvements
390.20	Structures and Improvements - Clearing
392.00	Transportation Equipment
396.00	Power Operated Equipment

Account 368.00, Line Transformers, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Aged plant accounting data for all plant accounts have been compiled for the years 1917 through 2018. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate is based on the statistical indications for the periods, 1917-2018 and 1969-2018. The Iowa 39-R1 is an excellent fit of the original survivor curve. The 39-year service life is within the typical service life range of 30 to 45 years for line transformers. The 39-year life reflects the Company's plans to systematically replace line transformers as they fail or need upgrades due to demand or load.

For Account 364.00, Poles, Towers and Fixtures, the aged accounting data for the period, 1939-2018, was analyzed. The statistical indications for the period, 1939-2018 and 1989-2018, were the primary basis for the selection of the 49-R1.5 survivor curve. The 49-year service life is within the typical range of 40-55 years for distribution poles.

The survivor curve estimates for the remaining accounts were based on judgment incorporating the statistical analyses and previous studies for this and other electric utilities.

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

Net Salvage Normalization

The net salvage component by account was based on historical data compiled for the five-year period, 2014-2018. Cost of removal and salvage were recorded each year by account. The totals by account were calculated to determine the annual net salvage amount that will be included in the total annual accrual rate. The amounts are set forth on Table 2 and brought forward to Table 1.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1,000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1,000\left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of March 31, 2019, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of March 31, 2019, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization, as defined in the Uniform System of Accounts, is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is appropriate for certain General Plant accounts that represent numerous units of property, but a very small portion of total depreciable electric plant in service. The accounts and their amortization periods are as follows:

Account	Amortization Period, Years
391.10, Office Furniture	25
391.15, Office Equipment	20
391.20, Personal Computers	5
391.25, Information Systems	5
393.00, Stores Equipment	30
394.00, Tools, Shop and Garage Equipment	25
395.00, Laboratory Equipment	20
397.00, Communication Equipment	20
398.00, Miscellaneous Equipment	20

For the purpose of calculating annual amortization amounts as of March 31, 2019, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable to the electric distribution plant in service as of March 31, 2019. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to March 31, 2019, is reasonable for a period of three to five years.

DESCRIPTION OF STATISTICAL SUPPORT

The service life estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric utility companies. The results of the statistical analyses of service life are presented in the section titled "Service Life Statistics".

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s), when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

DESCRIPTION OF DEPRECIATION TABULATIONS

Table 1 summarizes the results of the study, as applied to the original cost of electric plant as of March 31, 2019, is presented on pages VI-4 and VI-5 of this report. The schedule sets forth the original cost, the book reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric plant. Table 2 sets forth the five-year net salvage data for the period, 2014-2018, which is the basis for the net salvage normalization component of the depreciation accrual rate.

The tables of the calculated annual depreciation accruals are presented in account sequence in the section titled "Detailed Depreciation Calculations." The tables indicate the estimated survivor curve for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life and the calculated annual accrual amount.

JERSEY CENTRAL POWER & LIGHT COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK DEPRECIATION RESERVE, CALCULATED ANNUAL DEPRECIATION RATES AND NET SALVAGE NORMALIZATION RELATED TO ELECTRIC PLANT AS OF MARCH 31, 2019

	ACCOUNT	SURVIVOR CURVE	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE	NET SALVAGE NORMALIZATION ACCRUAL AMOUNT	NET SALVAGE NORMALIZATION ACCRUAL RATE	TOTAL ACCRUAL AMOUNT	TOTAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)	(9)	(10)=(9)/(3)	(11)=(6)+(9)	(12)=(11)/(3)
	ELECTRIC PLANT											
	MISCELLANEOUS INTANGIBLE PLANT											
303.00	MISCELLANEOUS INTANGIBLE PLANT	7-SQ	112,020,272.98	75,751,831	36,268,442	8,201,486	*	4.4	0	-	8,201,486	7.32
	TOTAL MISCELLANEOUS INTANGIBLE PLANT		**112,020,272.98**	**75,751,831**	**36,268,442**	**8,201,486**			0	-	8,201,486	7.32
	DISTRIBUTION PLANT											
360.12	DISTRIBUTION SUBSTATION EASEMENTS	80-R4	690,584.31	166,822	523,762	8,202	1.19	63.9	0	-	8,202	1.19
360.22	DISTRIBUTION LINE EASEMENTS	80-R4	26,255,822.88	18,035,097	8,220,726	159,317	0.61	51.6	0	-	159,317	0.61
361.10	STRUCTURES AND IMPROVEMENTS	70-R4	26,927,888.88	12,549,391	14,378,498	274,173	1.02	52.4	31,464	0.12	305,637	1.14
361.20	STRUCTURES AND IMPROVEMENTS - CLEARING	70-R4	19,617,181.78	1,125,891	18,491,291	275,439	1.40	67.1	0	-	275,439	1.40
362.00	STATION EQUIPMENT	59-R2	509,243,615.92	187,433,076	321,810,540	7,307,941	1.44	44.0	691,571	0.14	7,999,512	1.57
364.00	POLES, TOWERS AND FIXTURES	49-R1.5	721,698,575.07	233,919,464	487,779,111	13,139,389	1.82	37.1	5,405,093	0.75	18,544,482	2.57
365.00	OVERHEAD CONDUCTORS AND DEVICES	37-R1	903,378,663.86	145,710,380	757,668,284	27,867,513	3.08	27.2	7,170,139	0.79	35,037,652	3.88
365.10	OVERHEAD CONDUCTORS AND DEVICES - CLEARING	65-R5	180,229,094.35	31,839,895	148,389,199	2,754,241	1.53	53.9	0	-	2,754,241	1.53
366.00	UNDERGROUND CONDUIT	75-R4	116,213,888.14	57,724,371	58,489,517	1,166,637	1.00	50.1	24,115	0.02	1,190,752	1.02
367.00	UNDERGROUND CONDUCTORS AND DEVICES	45-S0.5	589,037,199.48	213,748,965	375,288,234	10,460,527	1.78	35.9	1,626,491	0.28	12,087,018	2.05
368.00	LINE TRANSFORMERS	39-R1	828,017,614.46	269,626,288	558,391,326	19,039,292	2.30	29.3	979,137	0.12	20,018,429	2.42
369.00	SERVICES	60-R2.5	463,545,815.39	183,925,838	279,619,977	7,102,700	1.53	39.4	(3,704)	0.00	7,098,996	1.53
370.00	METERS	23-L0.5	166,803,742.67	27,134,745	139,668,998	7,894,528	4.73	17.7	4,501,792	2.70	12,396,320	7.43
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	28-R2	25,623,447.28	7,525,015	18,098,432	1,283,921	5.01	14.1	120,036	0.47	1,403,957	5.48
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	28-R1.5	222,907,947.91	81,643,216	141,264,732	7,155,734	3.21	19.7	1,054,073	0.47	8,209,807	3.68
373.30	STREET LIGHTING AND SIGNAL SYSTEMS - LED	30-R0.5	356,052.66	3,063	352,990	11,962	3.36	29.5	222	0.06	12,184	3.42
	TOTAL DISTRIBUTION PLANT		**4,800,547,135.04**	**1,472,111,517**	**3,328,435,617**	**105,901,516**	**2.21**	**31.4**	**21,600,429**	**0.45**	**127,501,945**	**2.66**
	GENERAL PLANT											
389.20	LAND RIGHTS	50-R3	12,906.25	5,252	7,654	516	4.00	14.8	0	-	516	4.00
390.10	STRUCTURES AND IMPROVEMENTS	50-R1.5	87,445,213.88	42,718,702	44,726,512	1,213,261	1.39	36.9	134,507	0.15	1,347,768	1.54
390.20	STRUCTURES AND IMPROVEMENTS - CLEARING	60-R3	12,186,872.61	10,016,448	2,170,425	54,662	0.45	39.7	0	-	54,662	0.45
391.10	OFFICE FURNITURE											
	FULLY ACCRUED		1,282,688.83	1,282,689	0	0	-	-			-	-
	AMORTIZED	25-SQ	8,921,514.95	6,287,800	2,633,715	356,571	4.00	7.4	0	-	356,571	4.00
	TOTAL OFFICE FURNITURE		10,204,203.78	7,570,489	2,633,715	356,571	3.49		0	-	356,571	3.49
391.15	OFFICE EQUIPMENT	20-SQ	2,506,944.10	2,506,944	0	0	-	-	0	-	0 **	-
391.20	PERSONAL COMPUTERS											
	FULLY ACCRUED		2,684,774.35	2,684,774	0	0	-	-			-	-
	AMORTIZED	5-SQ	7,698,442.10	4,270,800	3,427,642	1,539,670	20.00	2.2	0	-	1,539,670	20.00
	TOTAL PERSONAL COMPUTERS		10,383,216.45	6,955,574	3,427,642	1,539,670	14.83		0	-	1,539,670	14.83
391.25	INFORMATION SYSTEMS	5-SQ	15,704.47	15,704	0	0	-	-	0	-	0 ***	-
392.00	TRANSPORTATION EQUIPMENT	13-L2	6,179,935.99	3,247,420	2,932,516	276,873	4.48	10.6	(772)	(0.01)	276,101	4.47
393.00	STORES EQUIPMENT											
	FULLY ACCRUED		30,113.41	30,113	0	0	-	-			-	-
	AMORTIZED	30-SQ	1,497,733.54	1,149,550	348,184	49,847	3.33	7.0	0	-	49,847	3.33
	TOTAL STORES EQUIPMENT		1,527,846.95	1,179,663	348,184	49,847	3.26		0	-	49,847	3.26
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT											
	FULLY ACCRUED		624,254.35	624,254	0	0	-	-			-	-
	AMORTIZED	25-SQ	19,505,234.01	9,817,700	9,687,534	779,264	4.00	12.4	0	-	779,264	4.00
	TOTAL TOOLS, SHOP AND GARAGE EQUIPMENT		20,129,488.36	10,441,954	9,687,534	779,264	3.87		0	-	779,264	3.87
395.00	LABORATORY EQUIPMENT											
	FULLY ACCRUED		73,468.10	73,468	0	0	-	-			-	-
	AMORTIZED	20-SQ	451,201.94	290,050	161,152	22,558	5.00	7.1	0	-	22,558	5.00
	TOTAL LABORATORY EQUIPMENT		524,670.04	363,518	161,152	22,558	4.30		0	-	22,558	4.30

JERSEY CENTRAL POWER & LIGHT COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK DEPRECIATION RESERVE, CALCULATED ANNUAL DEPRECIATION RATES AND NET SALVAGE NORMALIZATION RELATED TO ELECTRIC PLANT AS OF MARCH 31, 2019

	ACCOUNT (1)	SURVIVOR CURVE (2)	ORIGINAL COST (3)	BOOK DEPRECIATION RESERVE (4)	FUTURE ACCRUALS (5)	CALCULATED ANNUAL ACCRUAL AMOUNT (6)	CALCULATED ANNUAL ACCRUAL RATE (7)=(6)/(3)	COMPOSITE REMAINING LIFE (8)=(5)/(6)	NET SALVAGE NORMALIZATION ACCRUAL AMOUNT (9)	NET SALVAGE NORMALIZATION ACCRUAL RATE (10)=(9)/(3)	TOTAL ACCRUAL AMOUNT (11)=(6)+(9)	TOTAL ACCRUAL RATE (12)=(11)/(3)
396.00	POWER OPERATED EQUIPMENT	20-S1	4,368,478.17	2,765,837	1,602,641	140,952	3.23	11.4	(107)	0.00	140,845	3.22
397.00	COMMUNICATION EQUIPMENT											
	FULLY ACCRUED		31,705,051.42	31,705,051	0	0	-	-			-	-
	AMORTIZED	20-SQ	28,062,469.01	3,710,000	24,352,469	1,403,157	5.00	17.4	0	-	1,403,157	5.00
	TOTAL COMMUNICATION EQUIPMENT		59,767,520.43	35,415,051	24,352,469	1,403,157	2.35		0	-	1,403,157	2.35
398.00	MISCELLANEOUS EQUIPMENT											
	FULLY ACCRUED		290,776.18	290,776	0	0	-	-			-	-
	AMORTIZED	20-SQ	1,265,724.27	820,000	445,724	63,266	5.00	7.0	0	-	63,266	5.00
	TOTAL MISCELLANEOUS EQUIPMENT		1,556,500.45	1,110,776	445,724	63,266	4.06		0	-	63,266	4.06
	TOTAL GENERAL PLANT		**216,809,501.93**	**124,313,332**	**92,496,168**	**5,900,597**	**2.72**	**15.7**	**133,628**	**0.06**	**6,034,225**	**2.78**
	UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION											
391.10	OFFICE FURNITURE			(592,934)		148,234 ****					148,234	
391.15	OFFICE EQUIPMENT			(455,061)		113,765 ****					113,765	
391.20	PERSONAL COMPUTERS			(7,811,434)		1,952,859 ****					1,952,859	
391.25	INFORMATION SYSTEMS			(837)		209 ****					209	
393.00	STORES EQUIPMENT			55,763		(13,941) ****					(13,941)	
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT			(548,815)		137,204 ****					137,204	
395.00	LABORATORY EQUIPMENT			161,152		(40,288) ****					(40,288)	
397.00	COMMUNICATION EQUIPMENT			(1,438,103)		359,526 ****					359,526	
398.00	MISCELLANEOUS EQUIPMENT			81,628		(20,407) ****					(20,407)	
	TOTAL UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION			**(10,548,643)**		**2,637,161**					**2,637,161**	
	TOTAL DEPRECIABLE ELECTRIC PLANT		**5,129,376,909.95**	**1,661,628,038**	**3,457,200,227**	**122,640,760**	**2.39**		**21,734,057**	**0.42**	**144,374,817**	**2.81**
	NONDEPRECIABLE PLANT											
301.00	ORGNAIZATION		49,293.00									
302.00	FRANCHISES AND CONSENTS		16,447.00									
360.10	LAND		5,714,032.19	84								
374.00	ARC DISTRIBUTION PLANT		45,656.70	27,250								
389.10	LAND		1,488,774.98									
397.10	COMMUNCATOIN EQUIPMENT - FIBER OPTIC			57,332								
399.10	ARC GENERAL PLANT		1,465,281.77	308,531								
	TOTAL NONDEPRECIABLE PLANT		**8,779,485.64**	**393,197**								
	TOTAL ELECTRIC PLANT		**5,138,156,395.59**	**1,662,021,235**	**3,457,200,227**	**122,640,760**			**21,734,057**		**144,374,817**	

* Assets within the amortization period utilized a 14.29% annual accrual rate consistent with the amortization period.
** Assets as of January 1, 2019 will utilize a 5.00% annual accrual rate consistent with the amortization period.
*** Assets as of January 1, 2019 will utilize a 20.00% annual accrual rate consistent with the amortization period.
**** 4-Year amortization of unrecovered reserve related to amortization accounting. Amortization will begin January 1, 2021 and end December 31, 2024 to be consistent with associated Transmission filing period.

JERSEY CENTRAL POWER & LIGHT COMPANY

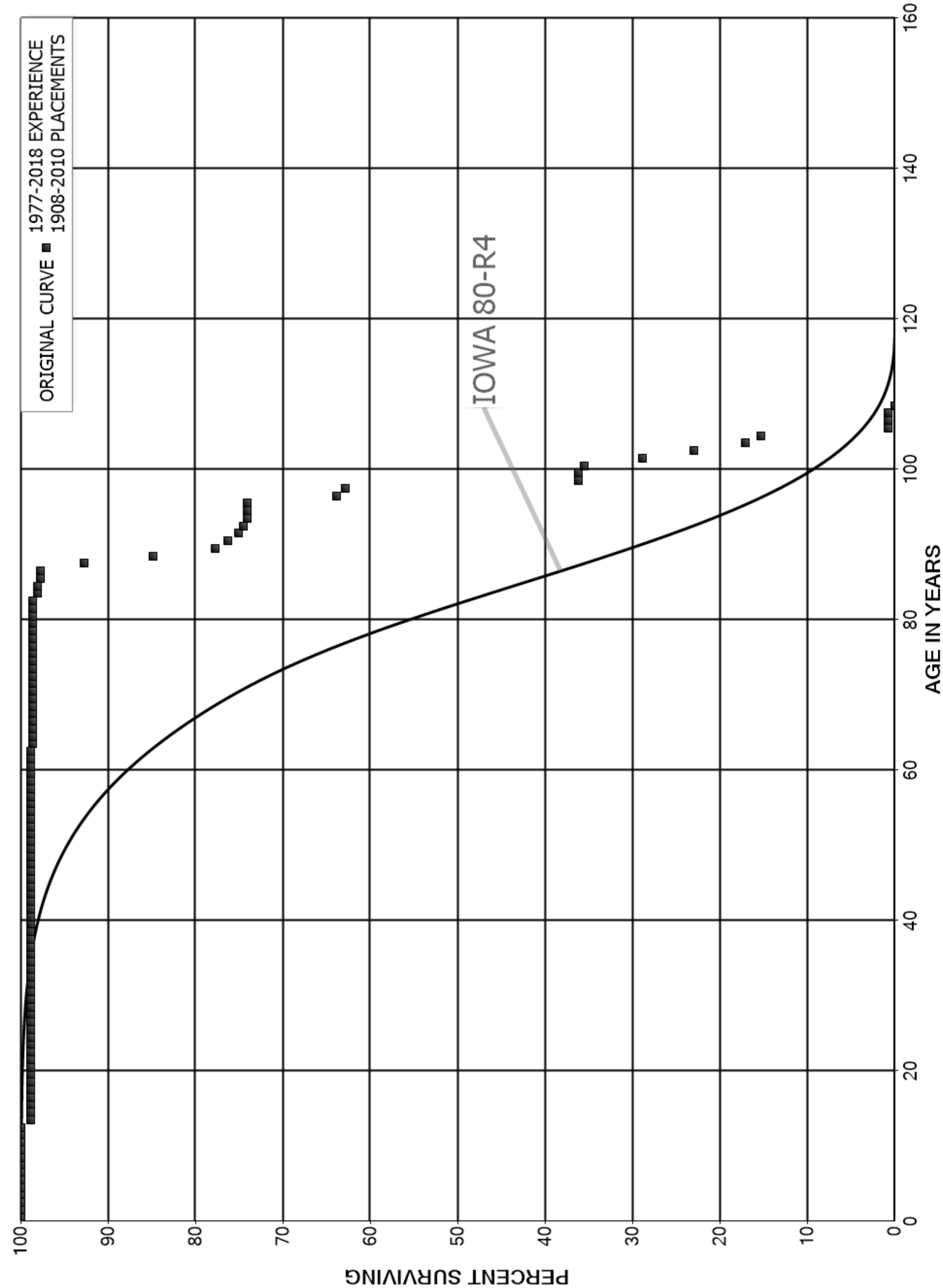
TABLE 2. 5-YEAR NET SALVAGE FOR NORMALIZATION

	2014		2015		2016		2017		2018			
ACCOUNT	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE	SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=-(12)/5
361.10	48.06		(7,031.13)		610.15		145,623.69		18,067.58		(157,318.35)	31,464
362.00	688,854.70		1,196,455.57		660,381.55		443,556.59		468,608.39		(3,457,856.80)	691,571
364.00	1,171,482.83		3,850,208.64		2,431,561.63		2,853,179.22		16,719,031.53		(27,025,463.85)	5,405,093
365.00	4,533,028.55		6,667,440.90		3,929,906.30		4,983,058.57		15,737,259.83		(35,850,694.15)	7,170,139
366.00	47,036.11		(4,548.47)		(25,918.14)		27,011.30		76,994.33		(120,575.13)	24,115
367.00	969,945.65		2,285,718.33		1,571,892.87		1,703,236.52		1,601,660.11		(8,132,453.48)	1,626,491
368.00	1,361,991.42	527,709.03	2,280,668.18	1,225,054.65	938,572.71	133,890.45	1,235,092.17	62,215.69	1,115,035.50	86,803.89	(4,895,686.27)	979,137
369.00	(7,784,668.94)	38,022.70	3,985,164.23		1,445,941.56		1,317,156.93		1,055,907.57		18,521.35	(3,704)
370.00	1,979,208.16		10,631,577.79		4,142,064.65		3,090,475.87		2,665,632.99		(22,508,959.46)	4,501,792
371.00	62,534.10		227,444.63		85,203.51		140,195.80		84,804.33		(600,182.37)	120,036
373.00	324,765.75		1,597,139.53		1,132,003.56		1,549,715.66		666,739.85		(5,270,364.35)	1,054,073
373.30					153.36		213.69		745.01		(1,112.06)	222
390.10	151,101.36		6,197.37						515,236.09		(672,534.82)	134,507
392.00				2,371.55			(1,486.41)				3,857.96	(772)
396.00							(533.89)				533.89	(107)
TOTAL	3,505,327.75	565,731.73	32,716,435.57	1,227,426.20	16,312,373.71	133,890.45	17,486,495.71	62,215.69	40,725,723.11	86,803.89	(108,670,287.89)	21,734,057

Schedule JJS-1

PART VII. SERVICE LIFE STATISTICS

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNTS 360.12 AND 360.22 EASEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNTS 360.12 AND 360.22 EASEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1908-2010 EXPERIENCE BAND 1977-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	21,933,464	0	0.0000	1.0000	100.00
0.5	22,349,947	14	0.0000	1.0000	100.00
1.5	22,825,965	16	0.0000	1.0000	100.00
2.5	22,914,661	2,141	0.0001	0.9999	100.00
3.5	23,334,991	18	0.0000	1.0000	99.99
4.5	23,619,785	10	0.0000	1.0000	99.99
5.5	23,991,814	14	0.0000	1.0000	99.99
6.5	24,256,291	18	0.0000	1.0000	99.99
7.5	24,551,764	42	0.0000	1.0000	99.99
8.5	24,814,388	61	0.0000	1.0000	99.99
9.5	25,079,841	64	0.0000	1.0000	99.99
10.5	25,317,129	55	0.0000	1.0000	99.99
11.5	25,153,439	49	0.0000	1.0000	99.99
12.5	25,136,884	282,503	0.0112	0.9888	99.99
13.5	25,018,801	57	0.0000	1.0000	98.87
14.5	25,165,079	81	0.0000	1.0000	98.87
15.5	25,281,787	66	0.0000	1.0000	98.86
16.5	25,410,413	127	0.0000	1.0000	98.86
17.5	25,509,828	109	0.0000	1.0000	98.86
18.5	23,959,726	62	0.0000	1.0000	98.86
19.5	24,019,637	62	0.0000	1.0000	98.86
20.5	22,772,491	88	0.0000	1.0000	98.86
21.5	22,426,159	117	0.0000	1.0000	98.86
22.5	22,176,516	360	0.0000	1.0000	98.86
23.5	21,522,291	91	0.0000	1.0000	98.86
24.5	20,929,597	98	0.0000	1.0000	98.86
25.5	19,343,425	85	0.0000	1.0000	98.86
26.5	17,722,508	100	0.0000	1.0000	98.86
27.5	16,238,816	86	0.0000	1.0000	98.86
28.5	15,234,998	106	0.0000	1.0000	98.86
29.5	14,392,624	94	0.0000	1.0000	98.86
30.5	13,322,301	170	0.0000	1.0000	98.86
31.5	12,564,779	110	0.0000	1.0000	98.86
32.5	11,494,082	117	0.0000	1.0000	98.85
33.5	10,867,180	183	0.0000	1.0000	98.85
34.5	9,171,611	134	0.0000	1.0000	98.85
35.5	8,337,297	115	0.0000	1.0000	98.85
36.5	7,882,924	107	0.0000	1.0000	98.85
37.5	7,390,165	100	0.0000	1.0000	98.85
38.5	6,732,590	241	0.0000	1.0000	98.85

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNTS 360.12 AND 360.22 EASEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2010 EXPERIENCE BAND 1977-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,073,771	88	0.0000	1.0000	98.84
40.5	5,481,591	92	0.0000	1.0000	98.84
41.5	5,066,758	78	0.0000	1.0000	98.84
42.5	4,564,784	64	0.0000	1.0000	98.84
43.5	4,227,191	54	0.0000	1.0000	98.84
44.5	3,810,823	32	0.0000	1.0000	98.84
45.5	3,527,335	29	0.0000	1.0000	98.84
46.5	3,158,519	24	0.0000	1.0000	98.83
47.5	2,898,182	26	0.0000	1.0000	98.83
48.5	2,602,592	29	0.0000	1.0000	98.83
49.5	2,339,404	26	0.0000	1.0000	98.83
50.5	2,075,397	22	0.0000	1.0000	98.83
51.5	1,651,561	26	0.0000	1.0000	98.83
52.5	1,431,250	124	0.0001	0.9999	98.83
53.5	1,240,050	20	0.0000	1.0000	98.82
54.5	1,065,518	31	0.0000	1.0000	98.82
55.5	919,403	14	0.0000	1.0000	98.81
56.5	797,595	10	0.0000	1.0000	98.81
57.5	692,356	52	0.0001	0.9999	98.81
58.5	589,271	18	0.0000	1.0000	98.80
59.5	517,537	31	0.0001	0.9999	98.80
60.5	456,352	34	0.0001	0.9999	98.80
61.5	407,368	31	0.0001	0.9999	98.79
62.5	387,284	462	0.0012	0.9988	98.78
63.5	365,225	93	0.0003	0.9997	98.66
64.5	350,909	10	0.0000	1.0000	98.64
65.5	333,017	5	0.0000	1.0000	98.64
66.5	320,081	5	0.0000	1.0000	98.63
67.5	305,595	7	0.0000	1.0000	98.63
68.5	294,359	7	0.0000	1.0000	98.63
69.5	280,810	16	0.0001	0.9999	98.63
70.5	270,431	18	0.0001	0.9999	98.62
71.5	261,414	3	0.0000	1.0000	98.61
72.5	247,552	20	0.0001	0.9999	98.61
73.5	243,598	4	0.0000	1.0000	98.61
74.5	239,868		0.0000	1.0000	98.60
75.5	219,234		0.0000	1.0000	98.60
76.5	216,373		0.0000	1.0000	98.60
77.5	205,755		0.0000	1.0000	98.60
78.5	196,121		0.0000	1.0000	98.60

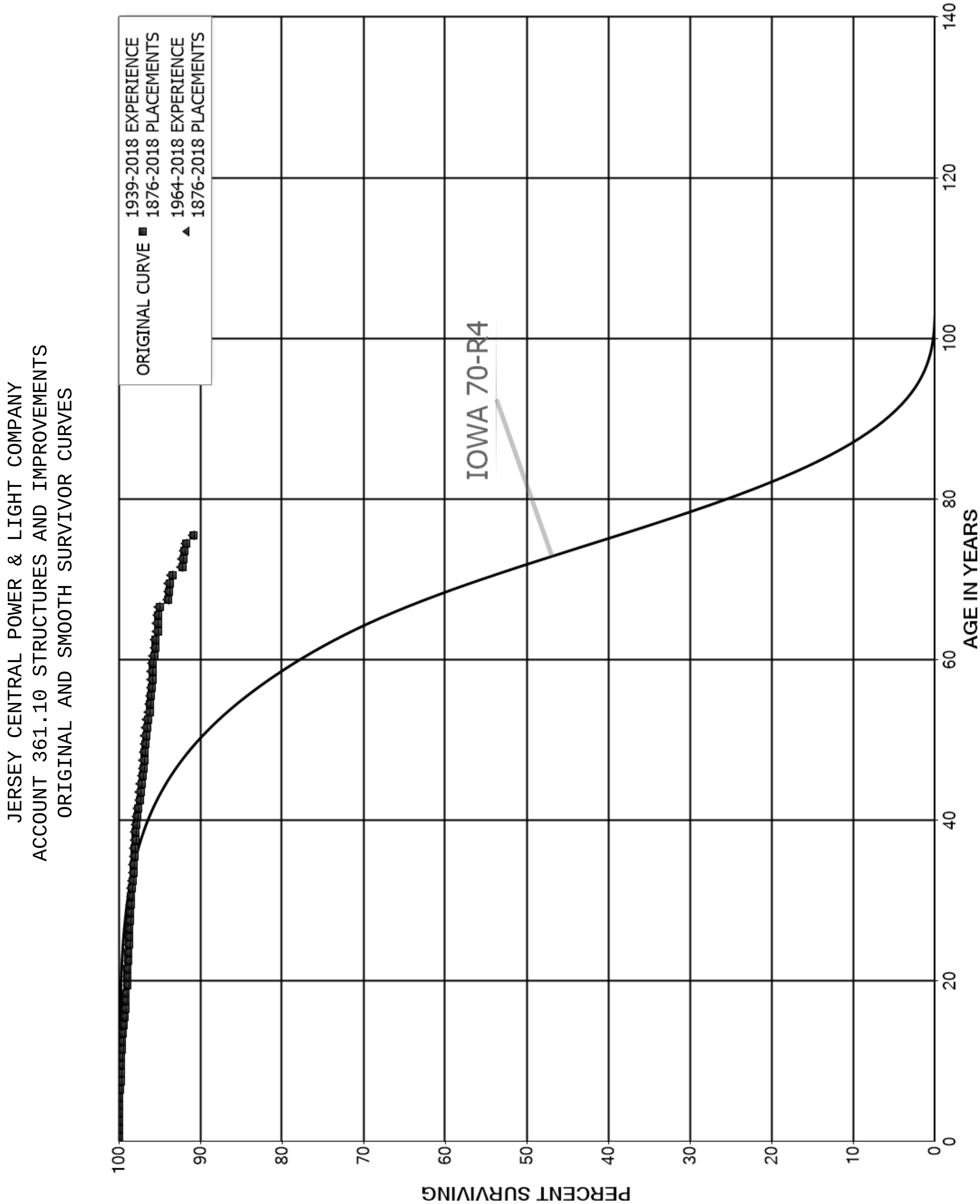
JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNTS 360.12 AND 360.22 EASEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2010 EXPERIENCE BAND 1977-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	187,993		0.0000	1.0000	98.60
80.5	51,208		0.0000	1.0000	98.60
81.5	50,117		0.0000	1.0000	98.60
82.5	47,764	256	0.0054	0.9946	98.60
83.5	46,585		0.0000	1.0000	98.08
84.5	45,507	159	0.0035	0.9965	98.08
85.5	43,973		0.0000	1.0000	97.73
86.5	42,704	2,198	0.0515	0.9485	97.73
87.5	37,536	3,207	0.0854	0.9146	92.70
88.5	31,714	2,645	0.0834	0.9166	84.78
89.5	29,069	528	0.0182	0.9818	77.71
90.5	28,541	483	0.0169	0.9831	76.30
91.5	28,058	173	0.0062	0.9938	75.01
92.5	27,885	184	0.0066	0.9934	74.55
93.5	27,701		0.0000	1.0000	74.06
94.5	27,701		0.0000	1.0000	74.06
95.5	27,701	3,835	0.1384	0.8616	74.06
96.5	23,866	344	0.0144	0.9856	63.80
97.5	23,522	10,000	0.4251	0.5749	62.88
98.5	13,522		0.0000	1.0000	36.15
99.5	13,522	232	0.0171	0.9829	36.15
100.5	13,291	2,503	0.1883	0.8117	35.53
101.5	10,788	2,225	0.2062	0.7938	28.84
102.5	8,564	2,161	0.2524	0.7476	22.89
103.5	6,402	673	0.1051	0.8949	17.12
104.5	5,729	5,454	0.9520	0.0480	15.32
105.5	275		0.0000	1.0000	0.74
106.5	275		0.0000	1.0000	0.74
107.5	275	275	1.0000		0.74
108.5					


JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE
1939-2018 EXPERIENCE
1876-2018 PLACEMENTS
1964-2018 EXPERIENCE
1876-2018 PLACEMENTS
IOWA 70-R4
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
20
40
60
80
100
120
140

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1876-2018 EXPERIENCE BAND 1939-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,776,013	0	0.0000	1.0000	100.00
0.5	13,590,896	0	0.0000	1.0000	100.00
1.5	15,406,987	320	0.0000	1.0000	100.00
2.5	12,542,323	25	0.0000	1.0000	100.00
3.5	12,547,685	230	0.0000	1.0000	100.00
4.5	13,275,325	1,453	0.0001	0.9999	100.00
5.5	14,346,684	24,072	0.0017	0.9983	99.98
6.5	14,085,409	5,564	0.0004	0.9996	99.82
7.5	14,272,829	1,830	0.0001	0.9999	99.78
8.5	15,763,731	5,006	0.0003	0.9997	99.76
9.5	16,343,771	1,178	0.0001	0.9999	99.73
10.5	16,155,378	20,502	0.0013	0.9987	99.73
11.5	15,884,237	4,294	0.0003	0.9997	99.60
12.5	15,653,746	10,786	0.0007	0.9993	99.57
13.5	14,354,126	20,129	0.0014	0.9986	99.50
14.5	14,412,126	11,122	0.0008	0.9992	99.36
15.5	14,427,277	13,164	0.0009	0.9991	99.29
16.5	14,418,737	2,429	0.0002	0.9998	99.20
17.5	14,473,964	2,676	0.0002	0.9998	99.18
18.5	14,551,590	31,579	0.0022	0.9978	99.16
19.5	14,618,612	3,134	0.0002	0.9998	98.95
20.5	14,524,018	4,386	0.0003	0.9997	98.93
21.5	14,726,303	10,077	0.0007	0.9993	98.90
22.5	13,751,118	1,660	0.0001	0.9999	98.83
23.5	13,200,351	11,320	0.0009	0.9991	98.82
24.5	13,185,663	1,329	0.0001	0.9999	98.73
25.5	12,820,700	6,226	0.0005	0.9995	98.72
26.5	10,309,150	3,285	0.0003	0.9997	98.67
27.5	9,949,053	5,833	0.0006	0.9994	98.64
28.5	9,869,365	4,640	0.0005	0.9995	98.58
29.5	8,460,306	5,015	0.0006	0.9994	98.54
30.5	7,912,698	5,532	0.0007	0.9993	98.48
31.5	7,440,812	8,965	0.0012	0.9988	98.41
32.5	6,711,680	6,619	0.0010	0.9990	98.29
33.5	6,507,936	3,296	0.0005	0.9995	98.20
34.5	6,318,072	5,316	0.0008	0.9992	98.15
35.5	6,301,185	2,785	0.0004	0.9996	98.06
36.5	6,188,874	4,795	0.0008	0.9992	98.02
37.5	6,233,848	3,104	0.0005	0.9995	97.94
38.5	6,260,651	3,610	0.0006	0.9994	97.89

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2018 EXPERIENCE BAND 1939-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,165,027	5,976	0.0010	0.9990	97.84
40.5	6,084,231	8,358	0.0014	0.9986	97.74
41.5	5,999,095	16,298	0.0027	0.9973	97.61
42.5	5,831,547	2,600	0.0004	0.9996	97.34
43.5	5,485,439	6,997	0.0013	0.9987	97.30
44.5	5,353,758	7,662	0.0014	0.9986	97.18
45.5	5,122,622	7,616	0.0015	0.9985	97.04
46.5	4,824,578	1,199	0.0002	0.9998	96.89
47.5	4,241,387	3,109	0.0007	0.9993	96.87
48.5	3,679,813	3,592	0.0010	0.9990	96.80
49.5	3,167,258	2,381	0.0008	0.9992	96.70
50.5	2,761,522	3,512	0.0013	0.9987	96.63
51.5	2,486,695	2,924	0.0012	0.9988	96.51
52.5	2,193,418	4,556	0.0021	0.9979	96.39
53.5	2,043,742	1,134	0.0006	0.9994	96.19
54.5	1,846,858	2,269	0.0012	0.9988	96.14
55.5	1,740,349	1,712	0.0010	0.9990	96.02
56.5	1,561,679	801	0.0005	0.9995	95.93
57.5	1,463,008	267	0.0002	0.9998	95.88
58.5	1,332,844	1,059	0.0008	0.9992	95.86
59.5	1,215,728	1,673	0.0014	0.9986	95.79
60.5	1,095,113	2,017	0.0018	0.9982	95.65
61.5	994,368	220	0.0002	0.9998	95.48
62.5	805,083	2,257	0.0028	0.9972	95.46
63.5	652,162	32	0.0000	1.0000	95.19
64.5	602,858	308	0.0005	0.9995	95.18
65.5	510,858	945	0.0018	0.9982	95.14
66.5	456,966	5,101	0.0112	0.9888	94.96
67.5	377,418	384	0.0010	0.9990	93.90
68.5	250,017	198	0.0008	0.9992	93.80
69.5	361,734	1,099	0.0030	0.9970	93.73
70.5	373,604	4,991	0.0134	0.9866	93.45
71.5	333,923	352	0.0011	0.9989	92.20
72.5	331,934	589	0.0018	0.9982	92.10
73.5	407,008	1,149	0.0028	0.9972	91.94
74.5	410,038	3,844	0.0094	0.9906	91.68
75.5	399,441	1,154	0.0029	0.9971	90.82
76.5	392,757	265	0.0007	0.9993	90.55
77.5	393,610	797	0.0020	0.9980	90.49
78.5	376,946	73	0.0002	0.9998	90.31

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2018 EXPERIENCE BAND 1939-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	393,374	4,128	0.0105	0.9895	90.29
80.5	387,653	4,108	0.0106	0.9894	89.35
81.5	382,863	16	0.0000	1.0000	88.40
82.5	382,684	3	0.0000	1.0000	88.39
83.5	382,573	3	0.0000	1.0000	88.39
84.5	382,494		0.0000	1.0000	88.39
85.5	381,438	3	0.0000	1.0000	88.39
86.5	377,834	130	0.0003	0.9997	88.39
87.5	352,040	14	0.0000	1.0000	88.36
88.5	228,040	711	0.0031	0.9969	88.36
89.5	223,394	18	0.0001	0.9999	88.08
90.5	211,241	272	0.0013	0.9987	88.08
91.5	190,379		0.0000	1.0000	87.96
92.5	105,631		0.0000	1.0000	87.96
93.5	83,482	412	0.0049	0.9951	87.96
94.5	77,965	38	0.0005	0.9995	87.53
95.5	61,778	2,278	0.0369	0.9631	87.49
96.5	60,754		0.0000	1.0000	84.26
97.5	60,451	42	0.0007	0.9993	84.26
98.5	60,227	4	0.0001	0.9999	84.20
99.5	66,057	802	0.0121	0.9879	84.20
100.5	66,382	112	0.0017	0.9983	83.17
101.5	66,203		0.0000	1.0000	83.03
102.5	66,201	302	0.0046	0.9954	83.03
103.5	65,858	28	0.0004	0.9996	82.66
104.5	65,779	1,885	0.0287	0.9713	82.62
105.5	63,877		0.0000	1.0000	80.25
106.5	54,307		0.0000	1.0000	80.25
107.5	54,127		0.0000	1.0000	80.25
108.5	50,447		0.0000	1.0000	80.25
109.5	50,447		0.0000	1.0000	80.25
110.5	50,447		0.0000	1.0000	80.25
111.5	52,688		0.0000	1.0000	80.25
112.5	52,688		0.0000	1.0000	80.25
113.5	26,579		0.0000	1.0000	80.25
114.5	26,579		0.0000	1.0000	80.25
115.5	26,579		0.0000	1.0000	80.25
116.5	26,579		0.0000	1.0000	80.25
117.5	18,606		0.0000	1.0000	80.25
118.5	17,539		0.0000	1.0000	80.25

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2018 EXPERIENCE BAND 1939-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	17,539		0.0000	1.0000	80.25
120.5	17,539		0.0000	1.0000	80.25
121.5	17,539		0.0000	1.0000	80.25
122.5	2,240	57	0.0254	0.9746	80.25
123.5	2,183	5	0.0023	0.9977	78.22
124.5	2,178	955	0.4383	0.5617	78.03
125.5	1,222		0.0000	1.0000	43.83
126.5	1,218		0.0000	1.0000	43.83
127.5	1,217		0.0000	1.0000	43.83
128.5	1,217		0.0000	1.0000	43.83
129.5	1,217		0.0000	1.0000	43.83
130.5	1,217		0.0000	1.0000	43.83
131.5	1,217		0.0000	1.0000	43.83
132.5	1,217		0.0000	1.0000	43.83
133.5	1,217		0.0000	1.0000	43.83
134.5	1,217		0.0000	1.0000	43.83
135.5	1,217		0.0000	1.0000	43.83
136.5	1,217		0.0000	1.0000	43.83
137.5	1,217		0.0000	1.0000	43.83
138.5	1,217		0.0000	1.0000	43.83
139.5	1,217		0.0000	1.0000	43.83
140.5	1,217		0.0000	1.0000	43.83
141.5	1,217		0.0000	1.0000	43.83
142.5					43.83

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1876-2018 EXPERIENCE BAND 1964-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,235,328	0	0.0000	1.0000	100.00
0.5	13,037,382	0	0.0000	1.0000	100.00
1.5	14,817,589		0.0000	1.0000	100.00
2.5	11,884,961	25	0.0000	1.0000	100.00
3.5	11,897,855	230	0.0000	1.0000	100.00
4.5	12,631,956	1,430	0.0001	0.9999	100.00
5.5	13,761,936	22,972	0.0017	0.9983	99.99
6.5	13,503,114	3,070	0.0002	0.9998	99.82
7.5	13,822,265	530	0.0000	1.0000	99.80
8.5	15,343,480	4,268	0.0003	0.9997	99.79
9.5	15,941,301	726	0.0000	1.0000	99.77
10.5	15,841,027	19,643	0.0012	0.9988	99.76
11.5	15,627,449	3,500	0.0002	0.9998	99.64
12.5	15,469,767	10,291	0.0007	0.9993	99.61
13.5	14,234,655	20,089	0.0014	0.9986	99.55
14.5	14,297,934	11,122	0.0008	0.9992	99.41
15.5	14,330,580	13,164	0.0009	0.9991	99.33
16.5	14,358,365	2,253	0.0002	0.9998	99.24
17.5	14,412,398	2,676	0.0002	0.9998	99.22
18.5	14,482,975	31,333	0.0022	0.9978	99.21
19.5	14,533,243	1,865	0.0001	0.9999	98.99
20.5	14,443,901	4,386	0.0003	0.9997	98.98
21.5	14,651,684	9,954	0.0007	0.9993	98.95
22.5	13,682,633	1,660	0.0001	0.9999	98.88
23.5	13,132,656	11,320	0.0009	0.9991	98.87
24.5	13,126,089	1,329	0.0001	0.9999	98.78
25.5	12,761,168	6,070	0.0005	0.9995	98.77
26.5	10,244,447	3,285	0.0003	0.9997	98.73
27.5	9,880,709	5,691	0.0006	0.9994	98.70
28.5	9,797,023	4,099	0.0004	0.9996	98.64
29.5	8,384,993	4,621	0.0006	0.9994	98.60
30.5	7,816,529	4,956	0.0006	0.9994	98.54
31.5	7,346,821	6,127	0.0008	0.9992	98.48
32.5	6,625,683	5,464	0.0008	0.9992	98.40
33.5	6,420,727	3,296	0.0005	0.9995	98.32
34.5	6,229,951	4,975	0.0008	0.9992	98.27
35.5	6,220,173	2,627	0.0004	0.9996	98.19
36.5	6,127,414	4,207	0.0007	0.9993	98.15
37.5	6,185,413	3,089	0.0005	0.9995	98.08
38.5	6,216,398	3,610	0.0006	0.9994	98.03

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2018 EXPERIENCE BAND 1964-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,126,774	5,976	0.0010	0.9990	97.97
40.5	6,062,965	8,263	0.0014	0.9986	97.88
41.5	5,987,601	14,032	0.0023	0.9977	97.74
42.5	5,822,692	2,600	0.0004	0.9996	97.52
43.5	5,476,584	6,997	0.0013	0.9987	97.47
44.5	5,344,903	7,662	0.0014	0.9986	97.35
45.5	5,113,767	7,616	0.0015	0.9985	97.21
46.5	4,811,707	1,199	0.0002	0.9998	97.06
47.5	4,228,517	3,109	0.0007	0.9993	97.04
48.5	3,666,943	3,592	0.0010	0.9990	96.97
49.5	3,154,388	1,936	0.0006	0.9994	96.87
50.5	2,749,097	3,512	0.0013	0.9987	96.81
51.5	2,478,384	2,924	0.0012	0.9988	96.69
52.5	2,185,581	4,556	0.0021	0.9979	96.57
53.5	2,039,920	1,134	0.0006	0.9994	96.37
54.5	1,843,036	2,269	0.0012	0.9988	96.32
55.5	1,736,528	1,712	0.0010	0.9990	96.20
56.5	1,557,858	801	0.0005	0.9995	96.11
57.5	1,459,187	267	0.0002	0.9998	96.06
58.5	1,329,023	1,059	0.0008	0.9992	96.04
59.5	1,211,907	1,673	0.0014	0.9986	95.96
60.5	1,091,292	2,017	0.0018	0.9982	95.83
61.5	994,368	220	0.0002	0.9998	95.65
62.5	805,083	2,257	0.0028	0.9972	95.63
63.5	652,162	32	0.0000	1.0000	95.36
64.5	602,858	308	0.0005	0.9995	95.36
65.5	510,858	945	0.0018	0.9982	95.31
66.5	456,966	5,101	0.0112	0.9888	95.13
67.5	377,418	384	0.0010	0.9990	94.07
68.5	250,017	198	0.0008	0.9992	93.98
69.5	361,734	1,099	0.0030	0.9970	93.90
70.5	373,604	4,991	0.0134	0.9866	93.62
71.5	333,923	352	0.0011	0.9989	92.37
72.5	331,934	589	0.0018	0.9982	92.27
73.5	407,008	1,149	0.0028	0.9972	92.11
74.5	410,038	3,844	0.0094	0.9906	91.85
75.5	399,441	1,154	0.0029	0.9971	90.98
76.5	392,757	265	0.0007	0.9993	90.72
77.5	393,610	797	0.0020	0.9980	90.66
78.5	376,946	73	0.0002	0.9998	90.48

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2018 EXPERIENCE BAND 1964-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	393,374	4,128	0.0105	0.9895	90.46
80.5	387,653	4,108	0.0106	0.9894	89.51
81.5	382,863	16	0.0000	1.0000	88.56
82.5	382,684	3	0.0000	1.0000	88.56
83.5	382,573	3	0.0000	1.0000	88.56
84.5	382,494		0.0000	1.0000	88.56
85.5	381,438	3	0.0000	1.0000	88.56
86.5	377,834	130	0.0003	0.9997	88.56
87.5	352,040	14	0.0000	1.0000	88.53
88.5	228,040	711	0.0031	0.9969	88.52
89.5	223,394	18	0.0001	0.9999	88.25
90.5	211,241	272	0.0013	0.9987	88.24
91.5	190,379		0.0000	1.0000	88.13
92.5	105,631		0.0000	1.0000	88.13
93.5	83,482	412	0.0049	0.9951	88.13
94.5	77,965	38	0.0005	0.9995	87.69
95.5	61,778	2,278	0.0369	0.9631	87.65
96.5	60,754		0.0000	1.0000	84.42
97.5	60,451	42	0.0007	0.9993	84.42
98.5	60,227	4	0.0001	0.9999	84.36
99.5	66,057	802	0.0121	0.9879	84.35
100.5	66,382	112	0.0017	0.9983	83.33
101.5	66,203		0.0000	1.0000	83.19
102.5	66,201	302	0.0046	0.9954	83.19
103.5	65,858	28	0.0004	0.9996	82.81
104.5	65,779	1,885	0.0287	0.9713	82.77
105.5	63,877		0.0000	1.0000	80.40
106.5	54,307		0.0000	1.0000	80.40
107.5	54,127		0.0000	1.0000	80.40
108.5	50,447		0.0000	1.0000	80.40
109.5	50,447		0.0000	1.0000	80.40
110.5	50,447		0.0000	1.0000	80.40
111.5	52,688		0.0000	1.0000	80.40
112.5	52,688		0.0000	1.0000	80.40
113.5	26,579		0.0000	1.0000	80.40
114.5	26,579		0.0000	1.0000	80.40
115.5	26,579		0.0000	1.0000	80.40
116.5	26,579		0.0000	1.0000	80.40
117.5	18,606		0.0000	1.0000	80.40
118.5	17,539		0.0000	1.0000	80.40

JERSEY CENTRAL POWER & LIGHT COMPANY

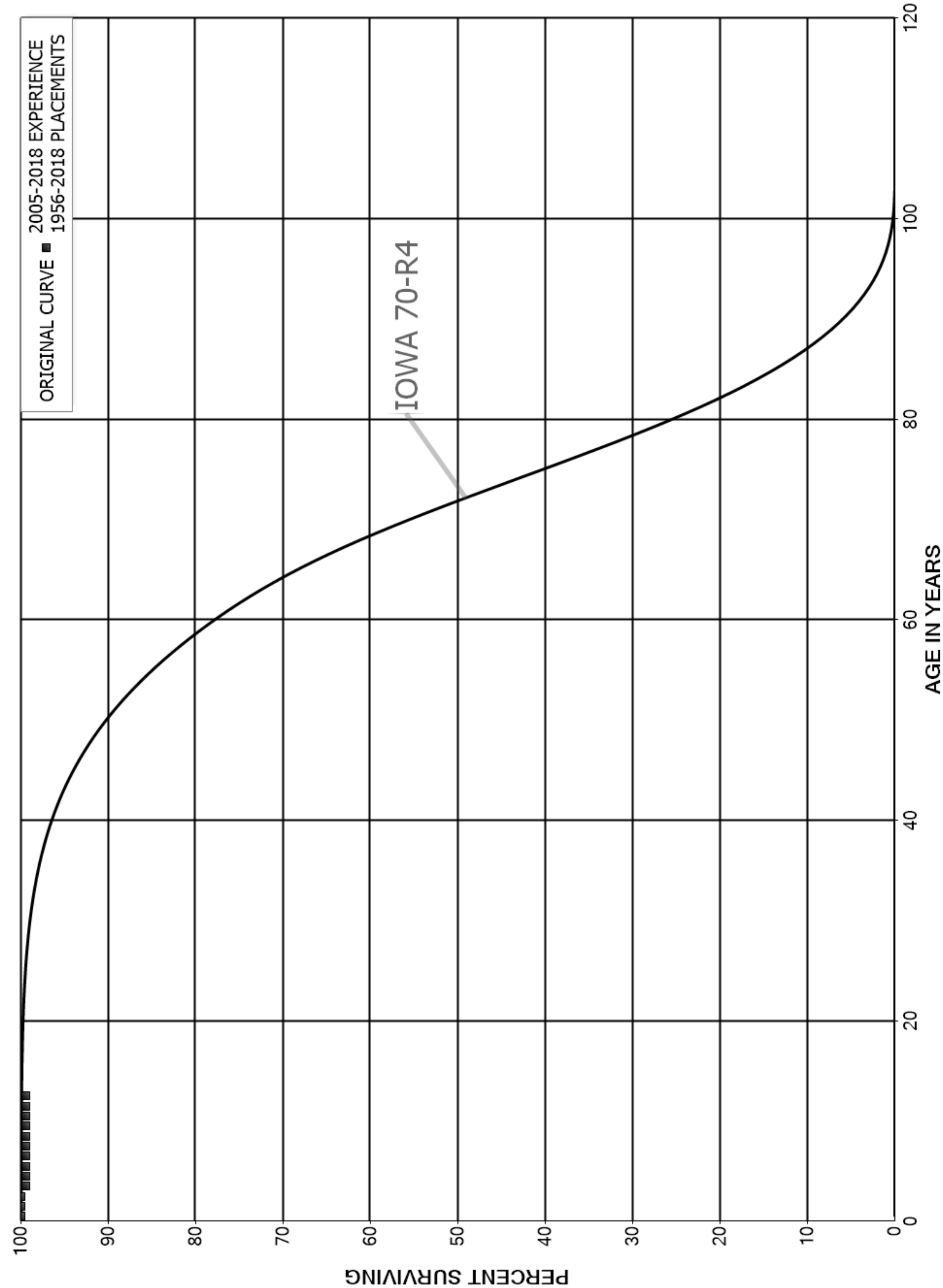
ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2018 EXPERIENCE BAND 1964-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	17,539		0.0000	1.0000	80.40
120.5	17,539		0.0000	1.0000	80.40
121.5	17,539		0.0000	1.0000	80.40
122.5	2,240	57	0.0254	0.9746	80.40
123.5	2,183	5	0.0023	0.9977	78.36
124.5	2,178	955	0.4383	0.5617	78.18
125.5	1,222		0.0000	1.0000	43.91
126.5	1,218		0.0000	1.0000	43.91
127.5	1,217		0.0000	1.0000	43.91
128.5	1,217		0.0000	1.0000	43.91
129.5	1,217		0.0000	1.0000	43.91
130.5	1,217		0.0000	1.0000	43.91
131.5	1,217		0.0000	1.0000	43.91
132.5	1,217		0.0000	1.0000	43.91
133.5	1,217		0.0000	1.0000	43.91
134.5	1,217		0.0000	1.0000	43.91
135.5	1,217		0.0000	1.0000	43.91
136.5	1,217		0.0000	1.0000	43.91
137.5	1,217		0.0000	1.0000	43.91
138.5	1,217		0.0000	1.0000	43.91
139.5	1,217		0.0000	1.0000	43.91
140.5	1,217		0.0000	1.0000	43.91
141.5	1,217		0.0000	1.0000	43.91
142.5					43.91

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 361.20 STRUCTURES AND IMPROVEMENTS - CLEARING
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.20 STRUCTURES AND IMPROVEMENTS - CLEARING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2018 EXPERIENCE BAND 2005-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,881,113		0.0000	1.0000	100.00
0.5	13,796,676		0.0000	1.0000	100.00
1.5	13,754,601		0.0000	1.0000	100.00
2.5	4,330,446	26,402	0.0061	0.9939	100.00
3.5	4,304,044		0.0000	1.0000	99.39
4.5	1,986,062		0.0000	1.0000	99.39
5.5	1,986,062		0.0000	1.0000	99.39
6.5	1,412,175		0.0000	1.0000	99.39
7.5	1,412,175		0.0000	1.0000	99.39
8.5	1,246,482		0.0000	1.0000	99.39
9.5	1,056,674		0.0000	1.0000	99.39
10.5	991,549		0.0000	1.0000	99.39
11.5	66,893		0.0000	1.0000	99.39
12.5					99.39
13.5					
14.5					
15.5					
16.5					
17.5					
18.5					
19.5					
20.5					
21.5					
22.5					
23.5					
24.5					
25.5					
26.5					
27.5					
28.5					
29.5					
30.5					
31.5					
32.5					
33.5					
34.5					
35.5					
36.5					
37.5					
38.5					

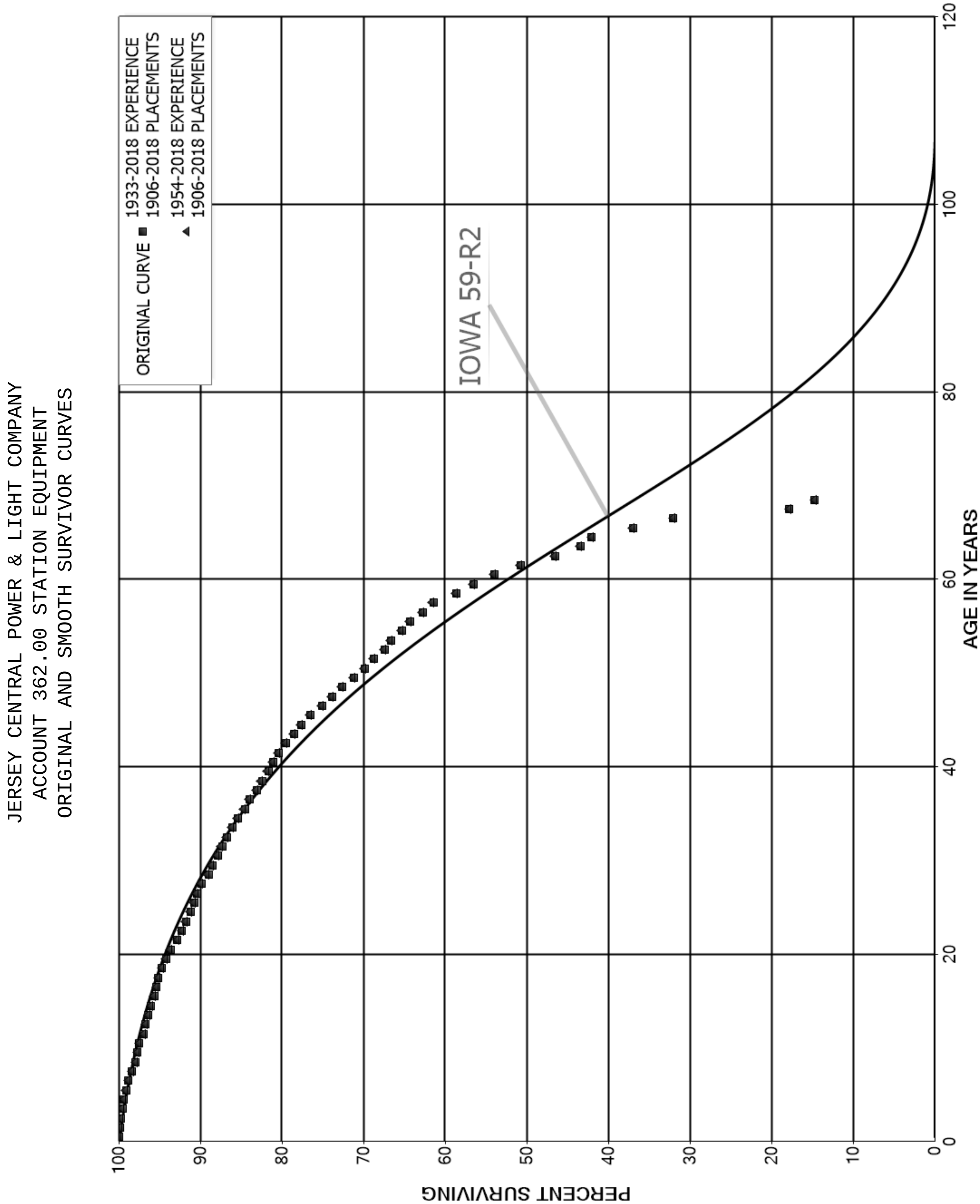
JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.20 STRUCTURES AND IMPROVEMENTS - CLEARING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2018 EXPERIENCE BAND 2005-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5					
40.5					
41.5					
42.5					
43.5					
44.5					
45.5					
46.5					
47.5					
48.5					
49.5					
50.5					
51.5					
52.5					
53.5					
54.5					
55.5					
56.5					
57.5					
58.5					
59.5	16,369		0.0000		
60.5	16,369		0.0000		
61.5	16,369		0.0000		
62.5					


JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 362.00 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE
■ 1933-2018 EXPERIENCE 1906-2018 PLACEMENTS
▲ 1954-2018 EXPERIENCE 1906-2018 PLACEMENTS
IOWA 59-R2
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
120

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1933-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	557,012,800	388,867	0.0007	0.9993	100.00
0.5	547,636,671	803,543	0.0015	0.9985	99.93
1.5	540,994,724	472,066	0.0009	0.9991	99.78
2.5	523,312,907	724,354	0.0014	0.9986	99.70
3.5	507,315,390	971,189	0.0019	0.9981	99.56
4.5	493,660,503	1,242,469	0.0025	0.9975	99.37
5.5	474,916,971	1,126,983	0.0024	0.9976	99.12
6.5	450,320,153	2,140,274	0.0048	0.9952	98.88
7.5	431,518,530	2,038,740	0.0047	0.9953	98.41
8.5	419,004,121	845,579	0.0020	0.9980	97.95
9.5	407,320,724	1,140,935	0.0028	0.9972	97.75
10.5	386,582,797	2,003,652	0.0052	0.9948	97.48
11.5	364,834,476	1,083,222	0.0030	0.9970	96.97
12.5	351,730,571	915,776	0.0026	0.9974	96.68
13.5	326,639,275	1,223,156	0.0037	0.9963	96.43
14.5	316,213,759	1,332,527	0.0042	0.9958	96.07
15.5	308,071,532	902,592	0.0029	0.9971	95.67
16.5	280,431,984	650,703	0.0023	0.9977	95.39
17.5	261,326,270	1,298,978	0.0050	0.9950	95.16
18.5	248,455,573	1,254,247	0.0050	0.9950	94.69
19.5	245,946,380	1,437,583	0.0058	0.9942	94.21
20.5	218,056,818	1,984,319	0.0091	0.9909	93.66
21.5	212,546,559	1,249,557	0.0059	0.9941	92.81
22.5	197,917,203	1,152,691	0.0058	0.9942	92.26
23.5	188,161,597	1,156,303	0.0061	0.9939	91.73
24.5	184,289,810	868,721	0.0047	0.9953	91.16
25.5	164,979,451	679,733	0.0041	0.9959	90.73
26.5	141,561,754	801,853	0.0057	0.9943	90.36
27.5	133,096,602	1,247,132	0.0094	0.9906	89.85
28.5	128,332,812	750,274	0.0058	0.9942	89.01
29.5	119,124,373	850,471	0.0071	0.9929	88.49
30.5	105,807,714	663,697	0.0063	0.9937	87.85
31.5	100,422,883	673,348	0.0067	0.9933	87.30
32.5	97,514,589	723,415	0.0074	0.9926	86.72
33.5	92,464,873	772,639	0.0084	0.9916	86.07
34.5	90,716,209	872,935	0.0096	0.9904	85.35
35.5	88,736,331	602,067	0.0068	0.9932	84.53
36.5	83,655,708	886,795	0.0106	0.9894	83.96
37.5	82,622,546	648,026	0.0078	0.9922	83.07
38.5	80,498,400	755,334	0.0094	0.9906	82.42

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1933-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	74,805,408	570,297	0.0076	0.9924	81.64
40.5	73,088,600	600,835	0.0082	0.9918	81.02
41.5	72,335,886	795,880	0.0110	0.9890	80.36
42.5	70,441,914	868,345	0.0123	0.9877	79.47
43.5	66,571,908	734,125	0.0110	0.9890	78.49
44.5	63,488,407	923,448	0.0145	0.9855	77.63
45.5	58,245,549	1,077,889	0.0185	0.9815	76.50
46.5	51,982,314	878,089	0.0169	0.9831	75.08
47.5	45,493,010	761,896	0.0167	0.9833	73.81
48.5	38,819,854	756,615	0.0195	0.9805	72.58
49.5	32,563,623	588,995	0.0181	0.9819	71.16
50.5	28,796,771	480,761	0.0167	0.9833	69.88
51.5	24,432,075	458,863	0.0188	0.9812	68.71
52.5	21,307,317	258,868	0.0121	0.9879	67.42
53.5	19,389,996	375,274	0.0194	0.9806	66.60
54.5	17,330,751	282,342	0.0163	0.9837	65.31
55.5	16,089,286	378,959	0.0236	0.9764	64.25
56.5	14,487,629	297,140	0.0205	0.9795	62.73
57.5	13,208,998	614,451	0.0465	0.9535	61.45
58.5	11,678,373	425,170	0.0364	0.9636	58.59
59.5	10,329,130	456,073	0.0442	0.9558	56.46
60.5	8,178,968	493,400	0.0603	0.9397	53.96
61.5	6,760,512	561,250	0.0830	0.9170	50.71
62.5	5,167,363	341,468	0.0661	0.9339	46.50
63.5	3,904,690	124,701	0.0319	0.9681	43.43
64.5	2,899,650	351,124	0.1211	0.8789	42.04
65.5	2,119,214	281,288	0.1327	0.8673	36.95
66.5	1,724,340	764,962	0.4436	0.5564	32.04
67.5	823,539	145,397	0.1766	0.8234	17.83
68.5	632,317	102,811	0.1626	0.8374	14.68
69.5	1,098,203	9,897	0.0090	0.9910	12.29
70.5	1,085,823	74,003	0.0682	0.9318	12.18
71.5	989,424	12,850	0.0130	0.9870	11.35
72.5	761,465	67,161	0.0882	0.9118	11.21
73.5	762,212	53,849	0.0706	0.9294	10.22
74.5	693,316	68,686	0.0991	0.9009	9.50
75.5	613,749	39,779	0.0648	0.9352	8.55
76.5	506,799	12,653	0.0250	0.9750	8.00
77.5	490,046	7,936	0.0162	0.9838	7.80
78.5	481,461	45,515	0.0945	0.9055	7.67

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1933-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	435,637	10,147	0.0233	0.9767	6.95
80.5	425,271	11,732	0.0276	0.9724	6.79
81.5	413,192	1,032	0.0025	0.9975	6.60
82.5	408,960	8,951	0.0219	0.9781	6.58
83.5	346,491	7,425	0.0214	0.9786	6.44
84.5	339,066	39,414	0.1162	0.8838	6.30
85.5	299,615	268,525	0.8962	0.1038	5.57
86.5	31,028	6,493	0.2093	0.7907	0.58
87.5	24,472	6,993	0.2858	0.7142	0.46
88.5	17,479	5,806	0.3322	0.6678	0.33
89.5	11,345	11,345	1.0000		0.22
90.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1954-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	553,890,110	387,593	0.0007	0.9993	100.00
0.5	544,867,079	791,464	0.0015	0.9985	99.93
1.5	538,614,518	465,942	0.0009	0.9991	99.78
2.5	521,784,292	719,090	0.0014	0.9986	99.70
3.5	506,112,852	963,582	0.0019	0.9981	99.56
4.5	492,561,113	1,238,806	0.0025	0.9975	99.37
5.5	474,095,974	1,124,066	0.0024	0.9976	99.12
6.5	449,599,696	2,132,885	0.0047	0.9953	98.89
7.5	430,583,351	2,028,751	0.0047	0.9953	98.42
8.5	418,006,270	842,096	0.0020	0.9980	97.95
9.5	406,182,645	1,133,361	0.0028	0.9972	97.76
10.5	385,358,082	1,991,659	0.0052	0.9948	97.48
11.5	363,778,361	1,068,483	0.0029	0.9971	96.98
12.5	350,898,860	908,240	0.0026	0.9974	96.70
13.5	325,891,539	1,220,115	0.0037	0.9963	96.44
14.5	315,551,355	1,329,415	0.0042	0.9958	96.08
15.5	307,089,498	895,142	0.0029	0.9971	95.68
16.5	279,345,572	637,757	0.0023	0.9977	95.40
17.5	260,150,604	1,274,506	0.0049	0.9951	95.18
18.5	247,051,231	1,219,959	0.0049	0.9951	94.72
19.5	244,291,095	1,425,841	0.0058	0.9942	94.25
20.5	216,184,063	1,958,080	0.0091	0.9909	93.70
21.5	210,592,591	1,179,972	0.0056	0.9944	92.85
22.5	196,324,654	1,112,156	0.0057	0.9943	92.33
23.5	186,816,840	1,126,257	0.0060	0.9940	91.81
24.5	183,212,952	841,515	0.0046	0.9954	91.25
25.5	164,181,493	652,631	0.0040	0.9960	90.83
26.5	140,921,885	787,338	0.0056	0.9944	90.47
27.5	132,705,517	1,219,577	0.0092	0.9908	89.97
28.5	128,081,232	734,907	0.0057	0.9943	89.14
29.5	118,933,763	837,005	0.0070	0.9930	88.63
30.5	105,727,960	659,703	0.0062	0.9938	88.00
31.5	100,356,237	671,752	0.0067	0.9933	87.46
32.5	97,457,080	719,971	0.0074	0.9926	86.87
33.5	92,413,748	768,503	0.0083	0.9917	86.23
34.5	90,656,568	867,953	0.0096	0.9904	85.51
35.5	88,688,801	601,962	0.0068	0.9932	84.69
36.5	83,630,982	886,029	0.0106	0.9894	84.12
37.5	82,616,140	647,488	0.0078	0.9922	83.23
38.5	80,497,685	755,334	0.0094	0.9906	82.57

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1954-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	74,804,736	570,297	0.0076	0.9924	81.80
40.5	73,088,064	600,595	0.0082	0.9918	81.18
41.5	72,335,692	795,880	0.0110	0.9890	80.51
42.5	70,441,843	868,320	0.0123	0.9877	79.62
43.5	66,571,861	734,125	0.0110	0.9890	78.64
44.5	63,488,360	923,448	0.0145	0.9855	77.77
45.5	58,245,503	1,077,889	0.0185	0.9815	76.64
46.5	51,982,268	878,089	0.0169	0.9831	75.22
47.5	45,493,010	761,896	0.0167	0.9833	73.95
48.5	38,819,854	756,615	0.0195	0.9805	72.72
49.5	32,563,623	588,995	0.0181	0.9819	71.30
50.5	28,796,771	480,761	0.0167	0.9833	70.01
51.5	24,432,075	458,863	0.0188	0.9812	68.84
52.5	21,307,317	258,868	0.0121	0.9879	67.55
53.5	19,389,996	375,274	0.0194	0.9806	66.73
54.5	17,330,751	282,342	0.0163	0.9837	65.44
55.5	16,089,286	378,959	0.0236	0.9764	64.37
56.5	14,487,629	297,140	0.0205	0.9795	62.85
57.5	13,208,998	614,451	0.0465	0.9535	61.56
58.5	11,678,373	425,170	0.0364	0.9636	58.70
59.5	10,329,130	456,073	0.0442	0.9558	56.56
60.5	8,178,968	493,400	0.0603	0.9397	54.07
61.5	6,760,512	561,250	0.0830	0.9170	50.80
62.5	5,167,363	341,468	0.0661	0.9339	46.59
63.5	3,904,690	124,701	0.0319	0.9681	43.51
64.5	2,899,650	351,124	0.1211	0.8789	42.12
65.5	2,119,214	281,288	0.1327	0.8673	37.02
66.5	1,724,340	764,962	0.4436	0.5564	32.10
67.5	823,539	145,397	0.1766	0.8234	17.86
68.5	632,317	102,811	0.1626	0.8374	14.71
69.5	1,098,203	9,897	0.0090	0.9910	12.32
70.5	1,085,823	74,003	0.0682	0.9318	12.21
71.5	989,424	12,850	0.0130	0.9870	11.37
72.5	761,465	67,161	0.0882	0.9118	11.23
73.5	762,212	53,849	0.0706	0.9294	10.24
74.5	693,316	68,686	0.0991	0.9009	9.51
75.5	613,749	39,779	0.0648	0.9352	8.57
76.5	506,799	12,653	0.0250	0.9750	8.02
77.5	490,046	7,936	0.0162	0.9838	7.82
78.5	481,461	45,515	0.0945	0.9055	7.69

JERSEY CENTRAL POWER & LIGHT COMPANY

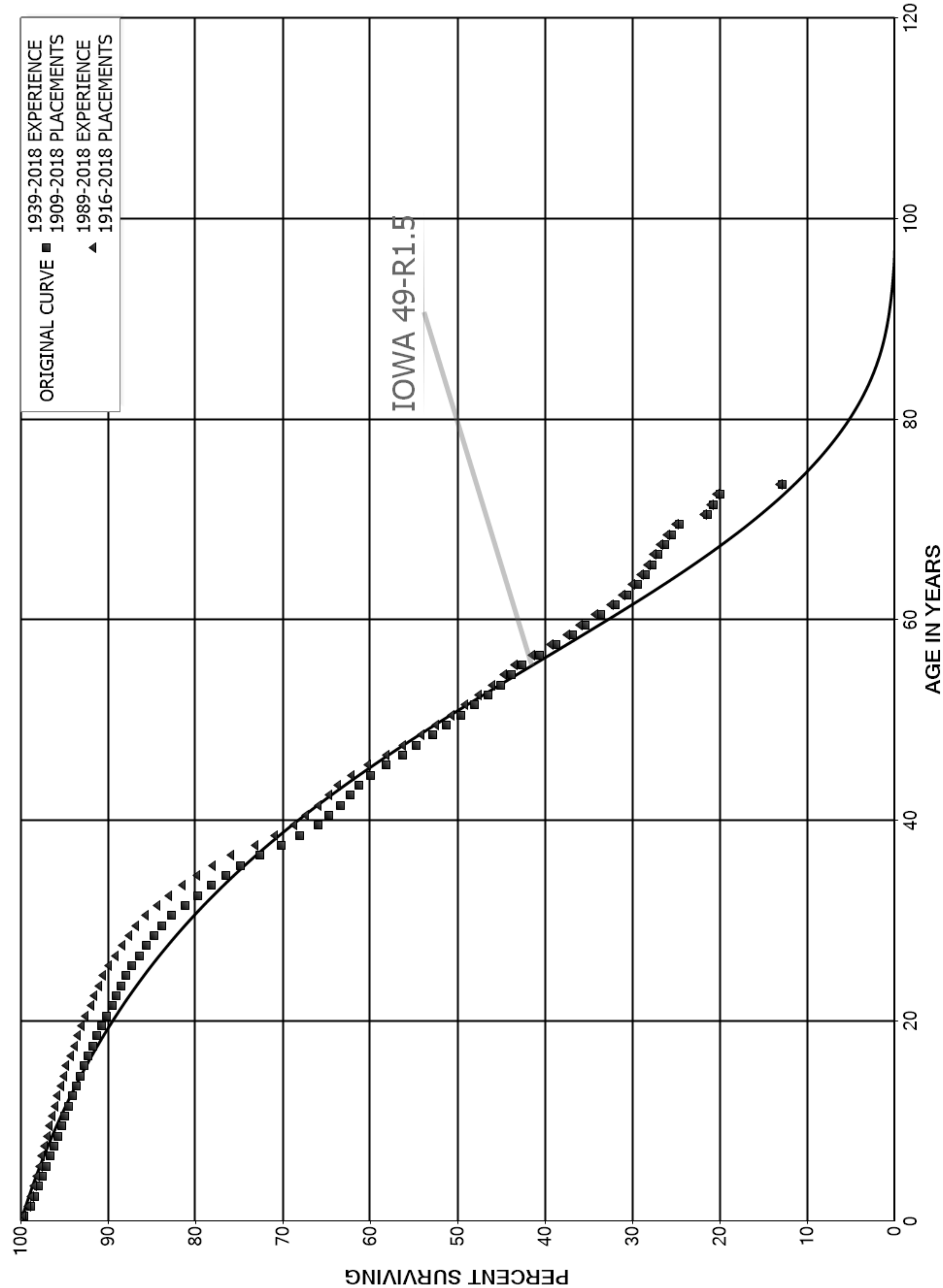
ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1954-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	435,637	10,147	0.0233	0.9767	6.96
80.5	425,271	11,732	0.0276	0.9724	6.80
81.5	413,192	1,032	0.0025	0.9975	6.61
82.5	408,960	8,951	0.0219	0.9781	6.60
83.5	346,491	7,425	0.0214	0.9786	6.45
84.5	339,066	39,414	0.1162	0.8838	6.31
85.5	299,615	268,525	0.8962	0.1038	5.58
86.5	31,028	6,493	0.2093	0.7907	0.58
87.5	24,472	6,993	0.2858	0.7142	0.46
88.5	17,479	5,806	0.3322	0.6678	0.33
89.5	11,345	11,345	1.0000		0.22
90.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1909-2018 EXPERIENCE BAND 1939-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	791,158,589	2,795,789	0.0035	0.9965	100.00
0.5	733,714,099	5,695,994	0.0078	0.9922	99.65
1.5	714,532,677	3,450,930	0.0048	0.9952	98.87
2.5	689,314,413	3,000,413	0.0044	0.9956	98.40
3.5	637,999,123	3,110,571	0.0049	0.9951	97.97
4.5	630,082,782	2,917,311	0.0046	0.9954	97.49
5.5	623,732,906	2,608,760	0.0042	0.9958	97.04
6.5	534,469,658	2,465,350	0.0046	0.9954	96.63
7.5	518,276,564	2,366,523	0.0046	0.9954	96.19
8.5	498,948,341	2,229,179	0.0045	0.9955	95.75
9.5	481,914,359	2,014,695	0.0042	0.9958	95.32
10.5	462,280,545	2,142,557	0.0046	0.9954	94.92
11.5	452,246,216	1,828,517	0.0040	0.9960	94.48
12.5	430,983,970	2,397,973	0.0056	0.9944	94.10
13.5	413,619,622	1,751,816	0.0042	0.9958	93.58
14.5	393,933,156	1,691,034	0.0043	0.9957	93.18
15.5	382,264,523	2,254,047	0.0059	0.9941	92.78
16.5	367,342,041	2,077,780	0.0057	0.9943	92.23
17.5	342,323,577	1,564,009	0.0046	0.9954	91.71
18.5	326,208,698	1,959,421	0.0060	0.9940	91.29
19.5	318,850,409	1,804,837	0.0057	0.9943	90.74
20.5	282,496,609	2,135,408	0.0076	0.9924	90.23
21.5	262,109,080	1,416,820	0.0054	0.9946	89.55
22.5	243,137,081	1,430,862	0.0059	0.9941	89.06
23.5	227,360,442	1,469,117	0.0065	0.9935	88.54
24.5	214,193,298	1,753,802	0.0082	0.9918	87.97
25.5	199,986,138	1,902,187	0.0095	0.9905	87.25
26.5	185,560,380	1,816,302	0.0098	0.9902	86.42
27.5	168,630,637	1,674,360	0.0099	0.9901	85.57
28.5	155,856,024	1,626,284	0.0104	0.9896	84.72
29.5	144,433,226	1,940,062	0.0134	0.9866	83.84
30.5	130,417,876	2,383,509	0.0183	0.9817	82.71
31.5	119,611,325	2,097,055	0.0175	0.9825	81.20
32.5	110,156,180	2,161,604	0.0196	0.9804	79.78
33.5	100,919,705	2,187,474	0.0217	0.9783	78.21
34.5	93,866,035	2,114,239	0.0225	0.9775	76.52
35.5	87,964,681	2,499,948	0.0284	0.9716	74.79
36.5	82,237,502	2,865,898	0.0348	0.9652	72.67
37.5	74,896,783	2,240,976	0.0299	0.9701	70.13
38.5	68,484,258	2,064,526	0.0301	0.9699	68.04

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2018 EXPERIENCE BAND 1939-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	62,251,960	1,170,485	0.0188	0.9812	65.98
40.5	57,901,203	1,232,417	0.0213	0.9787	64.74
41.5	53,736,705	914,957	0.0170	0.9830	63.37
42.5	49,586,003	769,938	0.0155	0.9845	62.29
43.5	46,141,800	1,057,232	0.0229	0.9771	61.32
44.5	40,506,508	1,179,398	0.0291	0.9709	59.91
45.5	35,451,977	1,148,047	0.0324	0.9676	58.17
46.5	31,119,964	888,212	0.0285	0.9715	56.29
47.5	27,990,611	923,549	0.0330	0.9670	54.68
48.5	25,197,966	755,928	0.0300	0.9700	52.88
49.5	21,759,779	728,635	0.0335	0.9665	51.29
50.5	18,416,735	559,256	0.0304	0.9696	49.57
51.5	15,548,479	509,713	0.0328	0.9672	48.07
52.5	13,126,799	405,194	0.0309	0.9691	46.49
53.5	11,137,217	308,166	0.0277	0.9723	45.06
54.5	9,727,311	270,393	0.0278	0.9722	43.81
55.5	8,786,081	399,861	0.0455	0.9545	42.59
56.5	8,781,699	427,150	0.0486	0.9514	40.65
57.5	8,284,967	400,800	0.0484	0.9516	38.68
58.5	7,863,719	312,453	0.0397	0.9603	36.80
59.5	7,104,318	337,682	0.0475	0.9525	35.34
60.5	6,537,087	342,610	0.0524	0.9476	33.66
61.5	5,609,426	227,767	0.0406	0.9594	31.90
62.5	5,170,888	197,040	0.0381	0.9619	30.60
63.5	4,794,835	158,299	0.0330	0.9670	29.44
64.5	4,580,221	114,066	0.0249	0.9751	28.47
65.5	4,460,721	113,549	0.0255	0.9745	27.76
66.5	4,308,363	120,155	0.0279	0.9721	27.05
67.5	3,970,079	114,278	0.0288	0.9712	26.30
68.5	3,784,585	140,011	0.0370	0.9630	25.54
69.5	3,621,288	469,124	0.1295	0.8705	24.59
70.5	2,943,157	100,358	0.0341	0.9659	21.41
71.5	2,664,847	91,589	0.0344	0.9656	20.68
72.5	2,446,739	876,036	0.3580	0.6420	19.97
73.5	220,165	52,951	0.2405	0.7595	12.82
74.5	134,536	60,942	0.4530	0.5470	9.74
75.5	6,324	1,154	0.1826	0.8174	5.33
76.5	5,170	3,840	0.7429	0.2571	4.35
77.5	1,329	60	0.0455	0.9545	1.12
78.5	1,269	474	0.3733	0.6267	1.07

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2018 EXPERIENCE BAND 1939-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	795		0.0000	1.0000	0.67
80.5	795		0.0000	1.0000	0.67
81.5	795	130	0.1635	0.8365	0.67
82.5	665	665	1.0000		0.56
83.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1916-2018 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	590,043,702	2,157,197	0.0037	0.9963	100.00
0.5	556,881,385	3,394,844	0.0061	0.9939	99.63
1.5	549,678,415	1,866,655	0.0034	0.9966	99.03
2.5	552,025,412	1,592,711	0.0029	0.9971	98.69
3.5	510,402,943	1,836,868	0.0036	0.9964	98.41
4.5	509,238,608	1,617,400	0.0032	0.9968	98.05
5.5	508,904,338	1,434,985	0.0028	0.9972	97.74
6.5	425,003,768	1,322,856	0.0031	0.9969	97.46
7.5	415,098,282	1,288,868	0.0031	0.9969	97.16
8.5	402,592,008	1,228,113	0.0031	0.9969	96.86
9.5	391,883,779	1,096,168	0.0028	0.9972	96.56
10.5	377,171,934	1,267,090	0.0034	0.9966	96.29
11.5	371,091,545	1,006,360	0.0027	0.9973	95.97
12.5	354,063,695	1,662,592	0.0047	0.9953	95.71
13.5	340,928,557	1,035,369	0.0030	0.9970	95.26
14.5	326,639,675	1,006,170	0.0031	0.9969	94.97
15.5	320,284,928	1,647,208	0.0051	0.9949	94.68
16.5	310,033,672	1,476,202	0.0048	0.9952	94.19
17.5	288,735,521	1,021,931	0.0035	0.9965	93.74
18.5	275,744,163	1,400,440	0.0051	0.9949	93.41
19.5	272,726,551	1,306,347	0.0048	0.9952	92.94
20.5	240,344,886	1,686,528	0.0070	0.9930	92.49
21.5	223,539,500	952,349	0.0043	0.9957	91.84
22.5	207,647,486	1,027,409	0.0049	0.9951	91.45
23.5	195,015,137	1,071,527	0.0055	0.9945	91.00
24.5	184,733,163	1,333,453	0.0072	0.9928	90.50
25.5	173,304,779	1,464,827	0.0085	0.9915	89.85
26.5	161,716,622	1,379,116	0.0085	0.9915	89.09
27.5	147,060,097	1,286,671	0.0087	0.9913	88.33
28.5	136,336,396	1,263,043	0.0093	0.9907	87.55
29.5	126,847,100	1,614,741	0.0127	0.9873	86.74
30.5	114,758,475	1,756,474	0.0153	0.9847	85.64
31.5	106,005,441	1,751,054	0.0165	0.9835	84.33
32.5	97,782,592	1,807,048	0.0185	0.9815	82.94
33.5	90,040,024	1,901,593	0.0211	0.9789	81.40
34.5	84,231,816	1,843,980	0.0219	0.9781	79.68
35.5	79,455,707	2,188,047	0.0275	0.9725	77.94
36.5	74,711,633	2,692,742	0.0360	0.9640	75.79
37.5	68,076,009	2,109,829	0.0310	0.9690	73.06
38.5	62,193,306	1,937,004	0.0311	0.9689	70.80

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2018 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	56,488,359	1,066,950	0.0189	0.9811	68.59
40.5	52,561,684	1,162,333	0.0221	0.9779	67.30
41.5	48,747,223	845,560	0.0173	0.9827	65.81
42.5	45,007,395	713,490	0.0159	0.9841	64.67
43.5	41,779,590	1,007,333	0.0241	0.9759	63.64
44.5	36,263,430	1,138,282	0.0314	0.9686	62.11
45.5	31,322,644	1,114,188	0.0356	0.9644	60.16
46.5	27,113,809	856,546	0.0316	0.9684	58.02
47.5	24,176,765	897,046	0.0371	0.9629	56.18
48.5	24,004,220	733,831	0.0306	0.9694	54.10
49.5	20,743,618	706,470	0.0341	0.9659	52.45
50.5	17,532,057	543,908	0.0310	0.9690	50.66
51.5	14,799,641	492,623	0.0333	0.9667	49.09
52.5	12,481,346	396,238	0.0317	0.9683	47.45
53.5	10,555,065	296,867	0.0281	0.9719	45.95
54.5	9,223,703	261,902	0.0284	0.9716	44.66
55.5	8,354,058	389,249	0.0466	0.9534	43.39
56.5	8,433,947	419,015	0.0497	0.9503	41.37
57.5	8,021,747	390,283	0.0487	0.9513	39.31
58.5	7,722,435	307,434	0.0398	0.9602	37.40
59.5	7,074,720	336,591	0.0476	0.9524	35.91
60.5	6,521,049	342,550	0.0525	0.9475	34.20
61.5	5,598,128	227,714	0.0407	0.9593	32.40
62.5	5,163,086	197,000	0.0382	0.9618	31.09
63.5	4,788,028	158,218	0.0330	0.9670	29.90
64.5	4,573,744	113,956	0.0249	0.9751	28.91
65.5	4,455,509	113,549	0.0255	0.9745	28.19
66.5	4,306,991	120,155	0.0279	0.9721	27.47
67.5	3,968,810	114,278	0.0288	0.9712	26.71
68.5	3,783,789	140,011	0.0370	0.9630	25.94
69.5	3,620,493	469,124	0.1296	0.8704	24.98
70.5	2,942,362	100,358	0.0341	0.9659	21.74
71.5	2,664,182	91,589	0.0344	0.9656	21.00
72.5	2,446,739	876,036	0.3580	0.6420	20.28
73.5	220,165	52,951	0.2405	0.7595	13.02
74.5	134,536	60,942	0.4530	0.5470	9.89
75.5	6,324	1,154	0.1826	0.8174	5.41
76.5	5,170	3,840	0.7429	0.2571	4.42
77.5	1,329	60	0.0455	0.9545	1.14
78.5	1,269	474	0.3733	0.6267	1.09

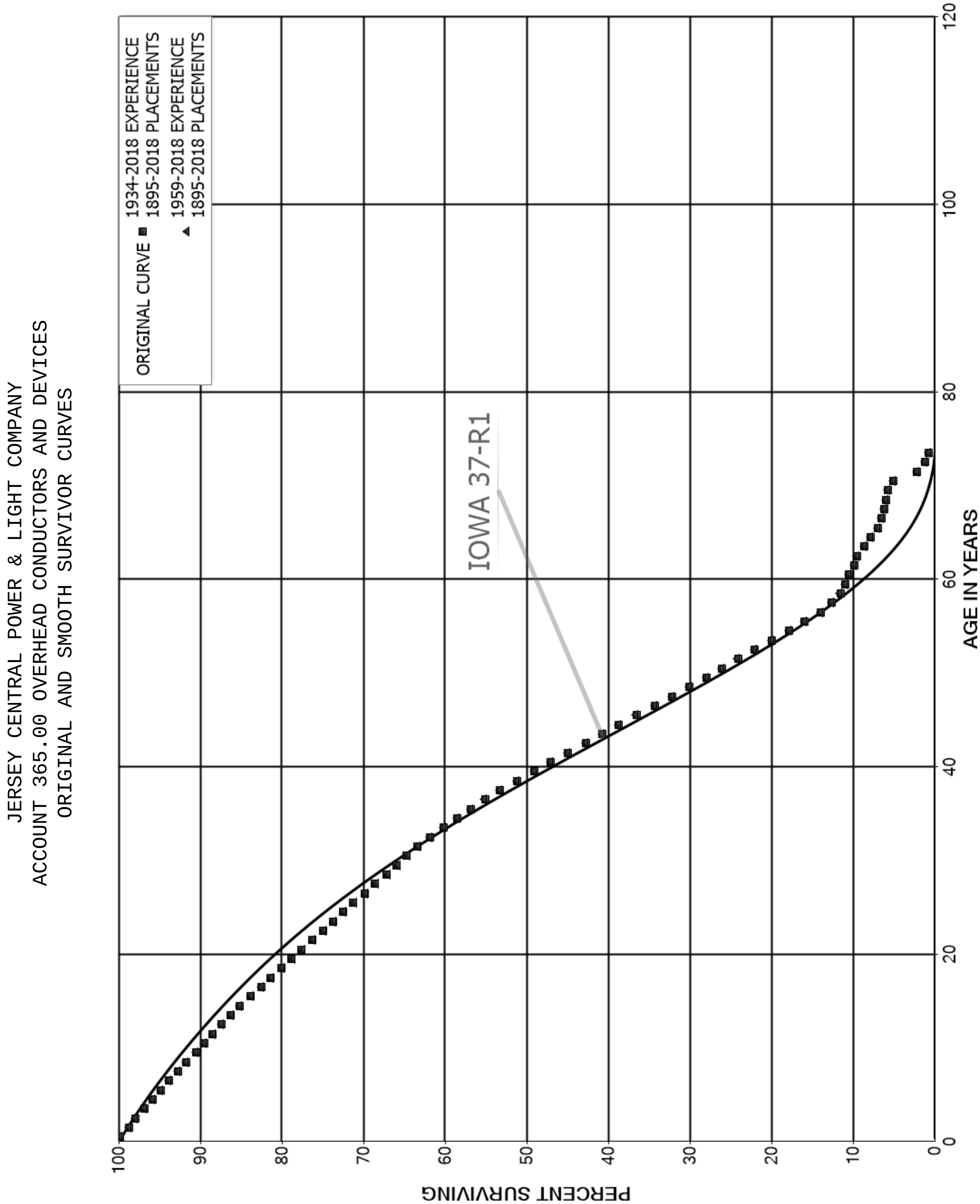
JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2018 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	795		0.0000	1.0000	0.68
80.5	795		0.0000	1.0000	0.68
81.5	795	130	0.1635	0.8365	0.68
82.5	665	665	1.0000		0.57
83.5					


JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE
1934-2018 EXPERIENCE
1895-2018 PLACEMENTS
1959-2018 EXPERIENCE
1895-2018 PLACEMENTS
IOWA 37-R1
PERCENT SURVIVING
AGE IN YEARS
0
20
40
60
80
100
120
10
30
50
70
90

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1934-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,134,125,682	2,450,303	0.0022	0.9978	100.00
0.5	1,068,583,424	11,033,415	0.0103	0.9897	99.78
1.5	1,028,289,729	8,861,020	0.0086	0.9914	98.75
2.5	970,918,229	10,222,446	0.0105	0.9895	97.90
3.5	904,833,018	9,209,058	0.0102	0.9898	96.87
4.5	866,375,337	9,136,400	0.0105	0.9895	95.89
5.5	839,095,117	9,277,774	0.0111	0.9889	94.87
6.5	651,263,842	7,372,676	0.0113	0.9887	93.83
7.5	620,429,250	7,080,508	0.0114	0.9886	92.76
8.5	586,415,109	7,441,485	0.0127	0.9873	91.70
9.5	552,639,978	6,303,071	0.0114	0.9886	90.54
10.5	523,545,586	6,050,416	0.0116	0.9884	89.51
11.5	500,060,166	6,033,086	0.0121	0.9879	88.47
12.5	463,623,856	6,183,660	0.0133	0.9867	87.41
13.5	440,947,873	5,191,442	0.0118	0.9882	86.24
14.5	417,890,392	6,837,708	0.0164	0.9836	85.23
15.5	397,197,616	6,062,596	0.0153	0.9847	83.83
16.5	376,384,215	5,418,589	0.0144	0.9856	82.55
17.5	351,116,687	5,629,688	0.0160	0.9840	81.36
18.5	330,838,328	5,271,985	0.0159	0.9841	80.06
19.5	319,865,895	4,907,939	0.0153	0.9847	78.78
20.5	282,620,208	4,551,230	0.0161	0.9839	77.57
21.5	267,691,254	4,664,560	0.0174	0.9826	76.32
22.5	254,167,650	4,259,501	0.0168	0.9832	74.99
23.5	239,865,610	3,960,800	0.0165	0.9835	73.74
24.5	227,750,470	3,983,724	0.0175	0.9825	72.52
25.5	215,909,649	4,195,371	0.0194	0.9806	71.25
26.5	202,668,487	3,738,433	0.0184	0.9816	69.87
27.5	187,592,666	3,857,335	0.0206	0.9794	68.58
28.5	176,782,059	3,225,244	0.0182	0.9818	67.17
29.5	165,709,308	3,149,856	0.0190	0.9810	65.94
30.5	154,877,899	3,025,186	0.0195	0.9805	64.69
31.5	146,459,808	3,560,888	0.0243	0.9757	63.43
32.5	139,093,433	3,818,148	0.0275	0.9725	61.88
33.5	132,916,463	3,697,789	0.0278	0.9722	60.19
34.5	127,116,060	3,637,654	0.0286	0.9714	58.51
35.5	121,342,084	3,728,567	0.0307	0.9693	56.84
36.5	116,252,178	3,877,762	0.0334	0.9666	55.09
37.5	110,404,917	4,340,661	0.0393	0.9607	53.25
38.5	103,547,493	4,219,434	0.0407	0.9593	51.16

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1934-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	96,567,788	4,031,135	0.0417	0.9583	49.07
40.5	90,258,722	4,079,222	0.0452	0.9548	47.03
41.5	84,233,397	4,103,207	0.0487	0.9513	44.90
42.5	78,075,562	3,649,727	0.0467	0.9533	42.71
43.5	72,784,499	3,599,073	0.0494	0.9506	40.72
44.5	65,793,908	3,657,757	0.0556	0.9444	38.70
45.5	59,088,715	3,619,108	0.0612	0.9388	36.55
46.5	52,731,494	3,338,582	0.0633	0.9367	34.31
47.5	47,199,207	3,126,105	0.0662	0.9338	32.14
48.5	42,058,553	2,843,544	0.0676	0.9324	30.01
49.5	36,087,433	2,440,940	0.0676	0.9324	27.98
50.5	31,274,106	2,374,595	0.0759	0.9241	26.09
51.5	26,074,130	2,201,446	0.0844	0.9156	24.11
52.5	21,471,284	2,094,503	0.0975	0.9025	22.07
53.5	17,559,876	1,830,057	0.1042	0.8958	19.92
54.5	14,415,175	1,533,953	0.1064	0.8936	17.84
55.5	11,551,011	1,453,098	0.1258	0.8742	15.95
56.5	11,398,642	1,095,633	0.0961	0.9039	13.94
57.5	10,302,956	854,368	0.0829	0.9171	12.60
58.5	9,448,559	512,614	0.0543	0.9457	11.55
59.5	8,935,776	326,007	0.0365	0.9635	10.93
60.5	8,609,678	539,279	0.0626	0.9374	10.53
61.5	8,070,020	312,697	0.0387	0.9613	9.87
62.5	7,757,211	750,192	0.0967	0.9033	9.49
63.5	7,006,854	565,080	0.0806	0.9194	8.57
64.5	6,441,655	742,853	0.1153	0.8847	7.88
65.5	5,698,667	357,160	0.0627	0.9373	6.97
66.5	5,341,415	292,293	0.0547	0.9453	6.53
67.5	5,049,055	198,039	0.0392	0.9608	6.18
68.5	4,850,865	171,256	0.0353	0.9647	5.93
69.5	4,679,482	550,392	0.1176	0.8824	5.72
70.5	4,128,985	2,361,263	0.5719	0.4281	5.05
71.5	1,767,687	841,386	0.4760	0.5240	2.16
72.5	926,290	323,092	0.3488	0.6512	1.13
73.5	68,328	20,621	0.3018	0.6982	0.74
74.5	47,687	20,451	0.4289	0.5711	0.52
75.5	27,235	21,030	0.7722	0.2278	0.29
76.5	6,205	1,116	0.1799	0.8201	0.07
77.5	5,086	490	0.0964	0.9036	0.05
78.5	4,595	2,261	0.4920	0.5080	0.05

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1934-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	2,334	464	0.1987	0.8013	0.03
80.5	1,870	28	0.0148	0.9852	0.02
81.5	1,843	26	0.0140	0.9860	0.02
82.5	1,817	13	0.0071	0.9929	0.02
83.5	1,804	253	0.1401	0.8599	0.02
84.5	1,551		0.0000	1.0000	0.02
85.5	1,551		0.0000	1.0000	0.02
86.5	1,551		0.0000	1.0000	0.02
87.5	1,551		0.0000	1.0000	0.02
88.5	1,551		0.0000	1.0000	0.02
89.5	1,551		0.0000	1.0000	0.02
90.5	1,551		0.0000	1.0000	0.02
91.5	1,551		0.0000	1.0000	0.02
92.5	1,551	0	0.0003	0.9997	0.02
93.5	1,551	0	0.0001	0.9999	0.02
94.5	1,550	0	0.0001	0.9999	0.02
95.5	1,550	2	0.0013	0.9987	0.02
96.5	1,548		0.0000	1.0000	0.02
97.5	2,020		0.0000	1.0000	0.02
98.5	2,020		0.0000	1.0000	0.02
99.5	2,020		0.0000	1.0000	0.02
100.5	2,020		0.0000	1.0000	0.02
101.5	2,020		0.0000	1.0000	0.02
102.5	2,020		0.0000	1.0000	0.02
103.5	2,020	542	0.2684	0.7316	0.02
104.5	1,477	87	0.0587	0.9413	0.01
105.5	1,383	306	0.2215	0.7785	0.01
106.5	1,077		0.0000	1.0000	0.01
107.5	1,077		0.0000	1.0000	0.01
108.5	1,077		0.0000	1.0000	0.01
109.5	1,077		0.0000	1.0000	0.01
110.5	1,077		0.0000	1.0000	0.01
111.5	1,077		0.0000	1.0000	0.01
112.5	1,077	1,077	1.0000		0.01
113.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1959-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,117,550,765	2,428,324	0.0022	0.9978	100.00
0.5	1,053,446,418	10,960,236	0.0104	0.9896	99.78
1.5	1,015,425,096	8,781,013	0.0086	0.9914	98.74
2.5	959,590,491	10,144,840	0.0106	0.9894	97.89
3.5	894,828,326	9,114,398	0.0102	0.9898	96.86
4.5	857,539,021	9,064,435	0.0106	0.9894	95.87
5.5	831,069,700	9,214,776	0.0111	0.9889	94.86
6.5	643,830,492	7,312,209	0.0114	0.9886	93.80
7.5	613,678,454	7,031,278	0.0115	0.9885	92.74
8.5	580,087,196	7,403,595	0.0128	0.9872	91.68
9.5	546,894,320	6,268,461	0.0115	0.9885	90.51
10.5	518,156,625	6,028,024	0.0116	0.9884	89.47
11.5	494,995,854	6,017,761	0.0122	0.9878	88.43
12.5	458,636,957	6,172,513	0.0135	0.9865	87.35
13.5	435,823,522	5,177,772	0.0119	0.9881	86.18
14.5	412,520,184	6,822,726	0.0165	0.9835	85.15
15.5	391,636,633	6,048,975	0.0154	0.9846	83.75
16.5	370,666,892	5,407,401	0.0146	0.9854	82.45
17.5	345,447,558	5,626,589	0.0163	0.9837	81.25
18.5	329,203,547	5,269,654	0.0160	0.9840	79.93
19.5	318,147,367	4,906,715	0.0154	0.9846	78.65
20.5	280,695,372	4,550,740	0.0162	0.9838	77.43
21.5	265,835,050	4,663,709	0.0175	0.9825	76.18
22.5	252,336,026	4,257,439	0.0169	0.9831	74.84
23.5	238,072,298	3,956,505	0.0166	0.9834	73.58
24.5	225,843,371	3,972,335	0.0176	0.9824	72.36
25.5	213,923,190	4,188,690	0.0196	0.9804	71.08
26.5	200,820,419	3,727,208	0.0186	0.9814	69.69
27.5	185,965,964	3,833,174	0.0206	0.9794	68.40
28.5	175,478,928	3,204,245	0.0183	0.9817	66.99
29.5	164,718,899	3,111,671	0.0189	0.9811	65.76
30.5	154,078,040	2,976,389	0.0193	0.9807	64.52
31.5	145,859,481	3,329,650	0.0228	0.9772	63.28
32.5	138,823,778	3,666,902	0.0264	0.9736	61.83
33.5	132,843,412	3,664,326	0.0276	0.9724	60.20
34.5	127,071,316	3,617,849	0.0285	0.9715	58.54
35.5	121,326,781	3,718,766	0.0307	0.9693	56.87
36.5	116,247,718	3,874,558	0.0333	0.9667	55.13
37.5	110,403,661	4,340,661	0.0393	0.9607	53.29
38.5	103,545,917	4,219,434	0.0407	0.9593	51.20

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1959-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	96,566,228	4,031,123	0.0417	0.9583	49.11
40.5	90,257,174	4,079,222	0.0452	0.9548	47.06
41.5	84,231,849	4,103,207	0.0487	0.9513	44.93
42.5	78,074,014	3,649,727	0.0467	0.9533	42.74
43.5	72,782,951	3,599,073	0.0494	0.9506	40.75
44.5	65,792,360	3,657,757	0.0556	0.9444	38.73
45.5	59,087,167	3,619,108	0.0613	0.9387	36.58
46.5	52,729,946	3,338,582	0.0633	0.9367	34.34
47.5	47,197,659	3,126,105	0.0662	0.9338	32.16
48.5	42,057,005	2,843,544	0.0676	0.9324	30.03
49.5	36,085,885	2,440,940	0.0676	0.9324	28.00
50.5	31,272,558	2,374,595	0.0759	0.9241	26.11
51.5	26,072,581	2,201,446	0.0844	0.9156	24.13
52.5	21,469,736	2,094,503	0.0976	0.9024	22.09
53.5	17,558,328	1,830,057	0.1042	0.8958	19.93
54.5	14,413,627	1,533,953	0.1064	0.8936	17.86
55.5	11,549,463	1,453,098	0.1258	0.8742	15.96
56.5	11,397,094	1,095,633	0.0961	0.9039	13.95
57.5	10,301,408	854,368	0.0829	0.9171	12.61
58.5	9,448,088	512,614	0.0543	0.9457	11.56
59.5	8,935,305	326,007	0.0365	0.9635	10.93
60.5	8,609,206	539,279	0.0626	0.9374	10.54
61.5	8,069,549	312,697	0.0388	0.9612	9.88
62.5	7,756,740	750,192	0.0967	0.9033	9.49
63.5	7,006,854	565,080	0.0806	0.9194	8.57
64.5	6,441,655	742,853	0.1153	0.8847	7.88
65.5	5,698,667	357,160	0.0627	0.9373	6.97
66.5	5,341,415	292,293	0.0547	0.9453	6.54
67.5	5,049,055	198,039	0.0392	0.9608	6.18
68.5	4,850,865	171,256	0.0353	0.9647	5.94
69.5	4,679,482	550,392	0.1176	0.8824	5.73
70.5	4,128,985	2,361,263	0.5719	0.4281	5.05
71.5	1,767,687	841,386	0.4760	0.5240	2.16
72.5	926,290	323,092	0.3488	0.6512	1.13
73.5	68,328	20,621	0.3018	0.6982	0.74
74.5	47,687	20,451	0.4289	0.5711	0.52
75.5	27,235	21,030	0.7722	0.2278	0.29
76.5	6,205	1,116	0.1799	0.8201	0.07
77.5	5,086	490	0.0964	0.9036	0.06
78.5	4,595	2,261	0.4920	0.5080	0.05

JERSEY CENTRAL POWER & LIGHT COMPANY

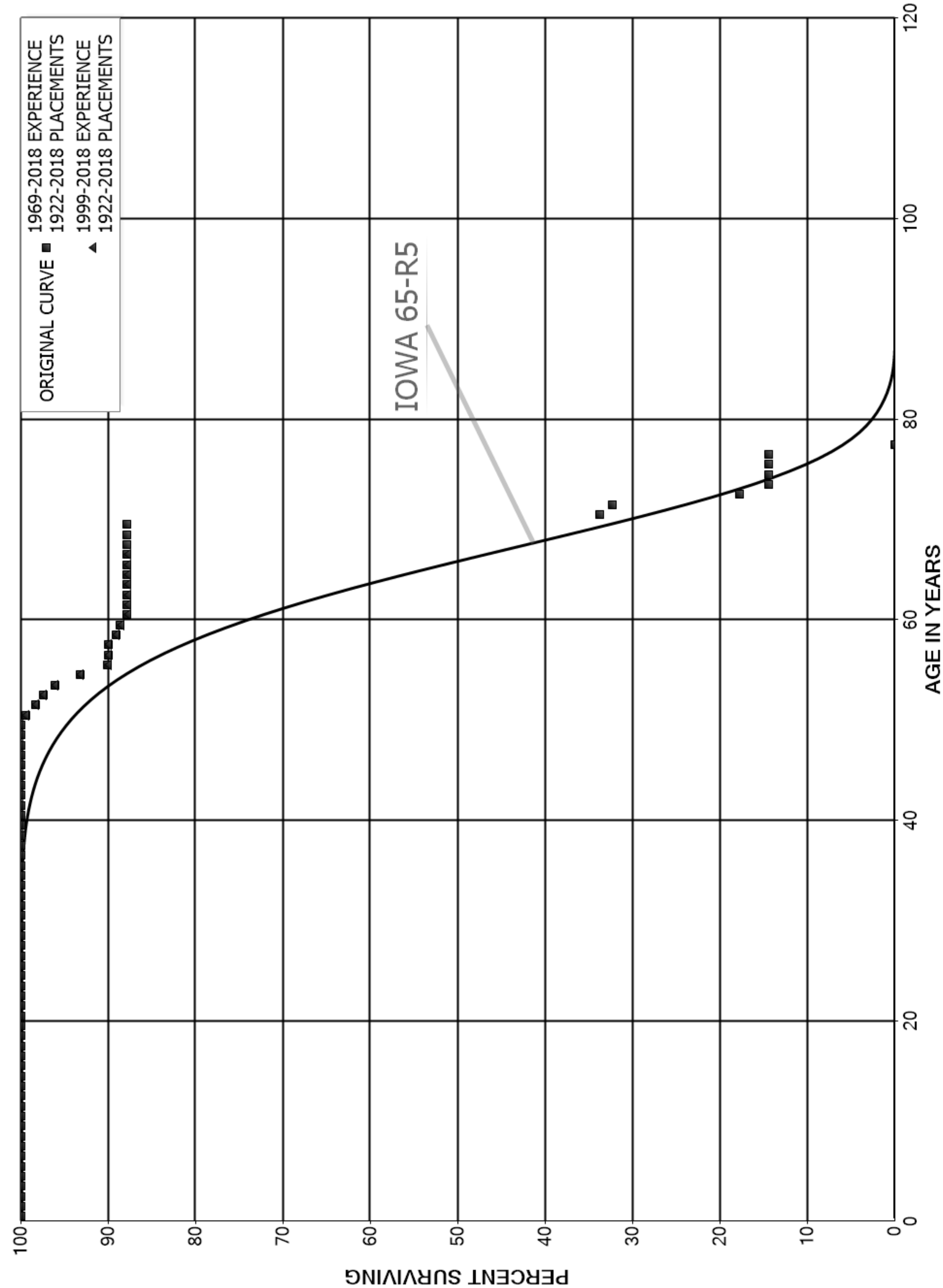
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1959-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	2,334	464	0.1987	0.8013	0.03
80.5	1,870	28	0.0148	0.9852	0.02
81.5	1,843	26	0.0140	0.9860	0.02
82.5	1,817	13	0.0071	0.9929	0.02
83.5	1,804	253	0.1401	0.8599	0.02
84.5	1,551		0.0000	1.0000	0.02
85.5	1,551		0.0000	1.0000	0.02
86.5	1,551		0.0000	1.0000	0.02
87.5	1,551		0.0000	1.0000	0.02
88.5	1,551		0.0000	1.0000	0.02
89.5	1,551		0.0000	1.0000	0.02
90.5	1,551		0.0000	1.0000	0.02
91.5	1,551		0.0000	1.0000	0.02
92.5	1,551	0	0.0003	0.9997	0.02
93.5	1,551	0	0.0001	0.9999	0.02
94.5	1,550	0	0.0001	0.9999	0.02
95.5	1,550	2	0.0013	0.9987	0.02
96.5	1,548		0.0000	1.0000	0.02
97.5	2,020		0.0000	1.0000	0.02
98.5	2,020		0.0000	1.0000	0.02
99.5	2,020		0.0000	1.0000	0.02
100.5	2,020		0.0000	1.0000	0.02
101.5	2,020		0.0000	1.0000	0.02
102.5	2,020		0.0000	1.0000	0.02
103.5	2,020	542	0.2684	0.7316	0.02
104.5	1,477	87	0.0587	0.9413	0.01
105.5	1,383	306	0.2215	0.7785	0.01
106.5	1,077		0.0000	1.0000	0.01
107.5	1,077		0.0000	1.0000	0.01
108.5	1,077		0.0000	1.0000	0.01
109.5	1,077		0.0000	1.0000	0.01
110.5	1,077		0.0000	1.0000	0.01
111.5	1,077		0.0000	1.0000	0.01
112.5	1,077	1,077	1.0000		0.01
113.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1922-2018 EXPERIENCE BAND 1969-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	173,398,073		0.0000	1.0000	100.00
0.5	155,130,662	220	0.0000	1.0000	100.00
1.5	136,851,013		0.0000	1.0000	100.00
2.5	136,372,458		0.0000	1.0000	100.00
3.5	129,029,456		0.0000	1.0000	100.00
4.5	118,396,432		0.0000	1.0000	100.00
5.5	80,618,057		0.0000	1.0000	100.00
6.5	81,126,090		0.0000	1.0000	100.00
7.5	71,781,035		0.0000	1.0000	100.00
8.5	66,020,843		0.0000	1.0000	100.00
9.5	45,610,769		0.0000	1.0000	100.00
10.5	40,996,424		0.0000	1.0000	100.00
11.5	40,235,341		0.0000	1.0000	100.00
12.5	37,447,644		0.0000	1.0000	100.00
13.5	37,537,369		0.0000	1.0000	100.00
14.5	32,830,694		0.0000	1.0000	100.00
15.5	32,536,374		0.0000	1.0000	100.00
16.5	31,913,906		0.0000	1.0000	100.00
17.5	30,879,449		0.0000	1.0000	100.00
18.5	30,117,930		0.0000	1.0000	100.00
19.5	29,586,702		0.0000	1.0000	100.00
20.5	27,334,381		0.0000	1.0000	100.00
21.5	26,562,157		0.0000	1.0000	100.00
22.5	25,316,861		0.0000	1.0000	100.00
23.5	24,543,937		0.0000	1.0000	100.00
24.5	23,837,345		0.0000	1.0000	100.00
25.5	22,876,441		0.0000	1.0000	100.00
26.5	21,694,652		0.0000	1.0000	100.00
27.5	20,906,123		0.0000	1.0000	100.00
28.5	20,450,641		0.0000	1.0000	100.00
29.5	19,717,948		0.0000	1.0000	100.00
30.5	18,875,910		0.0000	1.0000	100.00
31.5	18,266,878		0.0000	1.0000	100.00
32.5	17,302,367		0.0000	1.0000	100.00
33.5	16,847,001		0.0000	1.0000	100.00
34.5	16,307,146		0.0000	1.0000	100.00
35.5	15,847,524		0.0000	1.0000	100.00
36.5	15,378,804		0.0000	1.0000	100.00
37.5	14,800,002		0.0000	1.0000	100.00
38.5	13,903,006		0.0000	1.0000	100.00

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2018 EXPERIENCE BAND 1969-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,827,797		0.0000	1.0000	100.00
40.5	12,378,424		0.0000	1.0000	100.00
41.5	11,997,938		0.0000	1.0000	100.00
42.5	11,624,587		0.0000	1.0000	100.00
43.5	11,252,714		0.0000	1.0000	100.00
44.5	10,524,036		0.0000	1.0000	100.00
45.5	9,655,773		0.0000	1.0000	100.00
46.5	8,782,419		0.0000	1.0000	100.00
47.5	8,044,947		0.0000	1.0000	100.00
48.5	7,261,260		0.0000	1.0000	100.00
49.5	6,095,072	39,072	0.0064	0.9936	100.00
50.5	5,296,846	58,996	0.0111	0.9889	99.36
51.5	4,412,806	40,509	0.0092	0.9908	98.25
52.5	3,891,457	52,446	0.0135	0.9865	97.35
53.5	3,442,051	101,857	0.0296	0.9704	96.04
54.5	2,611,288	89,159	0.0341	0.9659	93.20
55.5	2,079,040	323	0.0002	0.9998	90.01
56.5	1,570,684	872	0.0006	0.9994	90.00
57.5	1,246,946	11,883	0.0095	0.9905	89.95
58.5	956,089	5,297	0.0055	0.9945	89.09
59.5	590,744	5,286	0.0089	0.9911	88.60
60.5	385,716		0.0000	1.0000	87.81
61.5	315,410		0.0000	1.0000	87.81
62.5	245,838		0.0000	1.0000	87.81
63.5	156,113		0.0000	1.0000	87.81
64.5	94,984		0.0000	1.0000	87.81
65.5	18,648		0.0000	1.0000	87.81
66.5	1,685		0.0000	1.0000	87.81
67.5	1,685		0.0000	1.0000	87.81
68.5	1,685		0.0000	1.0000	87.81
69.5	1,685	1,038	0.6161	0.3839	87.81
70.5	647	27	0.0417	0.9583	33.71
71.5	620	280	0.4513	0.5487	32.30
72.5	340	63	0.1849	0.8151	17.72
73.5	277		0.0000	1.0000	14.45
74.5	277		0.0000	1.0000	14.45
75.5	277		0.0000	1.0000	14.45
76.5	277	277	1.0000		14.45
77.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1922-2018 EXPERIENCE BAND 1999-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	149,139,203		0.0000	1.0000	100.00
0.5	132,966,563		0.0000	1.0000	100.00
1.5	114,694,810		0.0000	1.0000	100.00
2.5	115,035,945		0.0000	1.0000	100.00
3.5	108,088,878		0.0000	1.0000	100.00
4.5	97,436,653		0.0000	1.0000	100.00
5.5	60,177,671		0.0000	1.0000	100.00
6.5	61,360,333		0.0000	1.0000	100.00
7.5	52,492,825		0.0000	1.0000	100.00
8.5	46,914,491		0.0000	1.0000	100.00
9.5	26,882,294		0.0000	1.0000	100.00
10.5	22,910,246		0.0000	1.0000	100.00
11.5	22,687,888		0.0000	1.0000	100.00
12.5	20,750,093		0.0000	1.0000	100.00
13.5	21,205,459		0.0000	1.0000	100.00
14.5	16,977,510		0.0000	1.0000	100.00
15.5	17,066,475		0.0000	1.0000	100.00
16.5	16,851,770		0.0000	1.0000	100.00
17.5	16,387,078		0.0000	1.0000	100.00
18.5	16,482,046		0.0000	1.0000	100.00
19.5	16,974,619		0.0000	1.0000	100.00
20.5	15,118,839		0.0000	1.0000	100.00
21.5	14,667,509		0.0000	1.0000	100.00
22.5	13,740,320		0.0000	1.0000	100.00
23.5	13,319,403		0.0000	1.0000	100.00
24.5	13,338,378		0.0000	1.0000	100.00
25.5	13,245,413		0.0000	1.0000	100.00
26.5	12,938,818		0.0000	1.0000	100.00
27.5	12,873,443		0.0000	1.0000	100.00
28.5	13,196,351		0.0000	1.0000	100.00
29.5	13,624,561		0.0000	1.0000	100.00
30.5	13,541,677		0.0000	1.0000	100.00
31.5	13,757,688		0.0000	1.0000	100.00
32.5	13,274,017		0.0000	1.0000	100.00
33.5	13,215,611		0.0000	1.0000	100.00
34.5	13,404,662		0.0000	1.0000	100.00
35.5	13,388,130		0.0000	1.0000	100.00
36.5	13,427,443		0.0000	1.0000	100.00
37.5	13,171,507		0.0000	1.0000	100.00
38.5	12,553,485		0.0000	1.0000	100.00

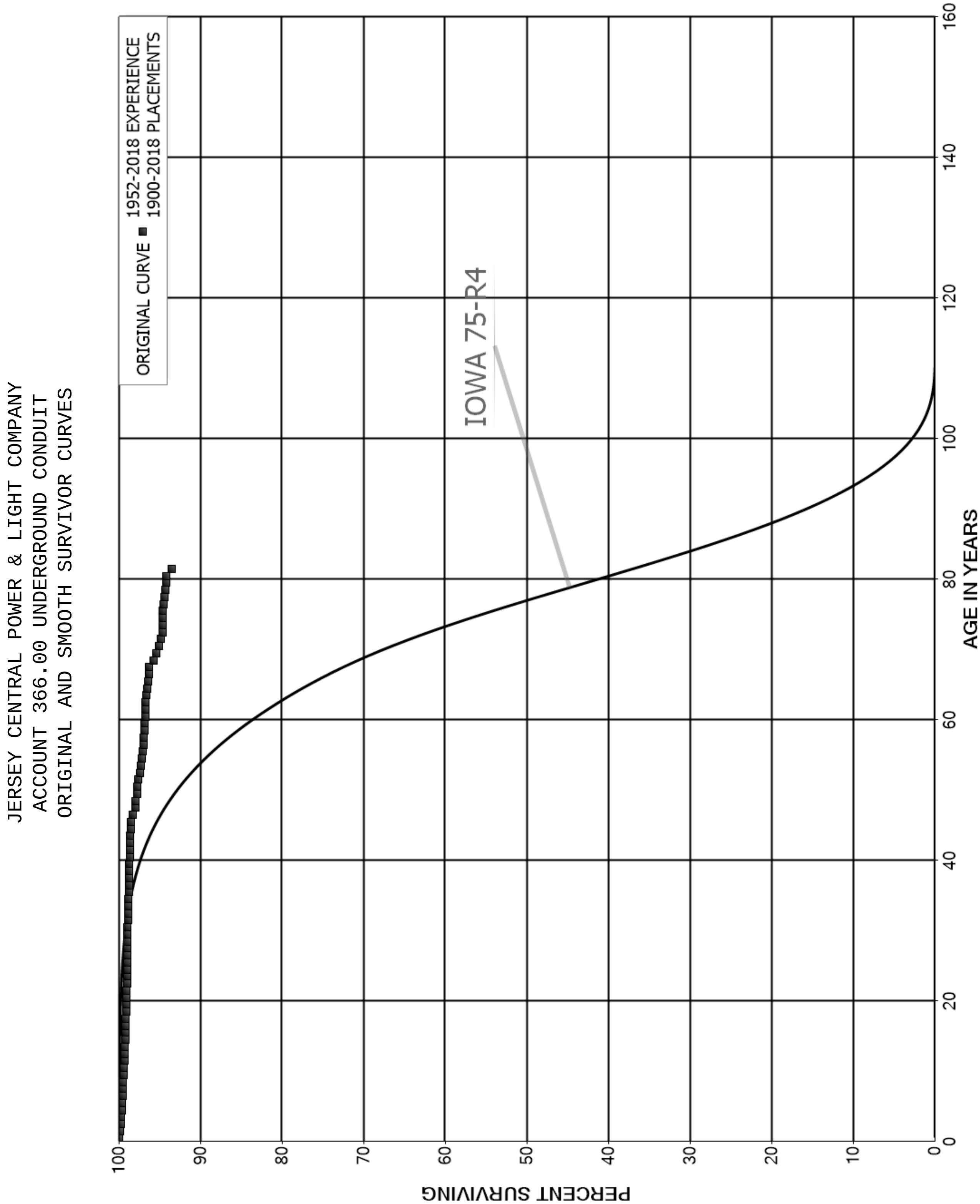
JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2018 EXPERIENCE BAND 1999-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	11,837,285		0.0000	1.0000	100.00
40.5	11,587,628		0.0000	1.0000	100.00
41.5	11,277,169		0.0000	1.0000	100.00
42.5	10,973,326		0.0000	1.0000	100.00
43.5	10,691,179		0.0000	1.0000	100.00
44.5	10,023,629		0.0000	1.0000	100.00
45.5	9,231,703		0.0000	1.0000	100.00
46.5	8,416,594		0.0000	1.0000	100.00
47.5	7,735,632		0.0000	1.0000	100.00
48.5	6,992,454		0.0000	1.0000	100.00
49.5	5,878,711	39,072	0.0066	0.9934	100.00
50.5	5,133,344	58,996	0.0115	0.9885	99.34
51.5	4,309,176	40,509	0.0094	0.9906	98.19
52.5	3,843,134	52,446	0.0136	0.9864	97.27
53.5	3,413,594	101,857	0.0298	0.9702	95.94
54.5	2,585,943	89,159	0.0345	0.9655	93.08
55.5	2,054,018	323	0.0002	0.9998	89.87
56.5	1,546,533	872	0.0006	0.9994	89.86
57.5	1,234,678	11,883	0.0096	0.9904	89.81
58.5	949,118	5,297	0.0056	0.9944	88.94
59.5	589,060	5,286	0.0090	0.9910	88.45
60.5	384,032		0.0000	1.0000	87.65
61.5	313,725		0.0000	1.0000	87.65
62.5	244,153		0.0000	1.0000	87.65
63.5	154,428		0.0000	1.0000	87.65
64.5	93,300		0.0000	1.0000	87.65
65.5	16,963		0.0000	1.0000	87.65
66.5					87.65
67.5					
68.5					
69.5	1,038	1,038	1.0000		
70.5	27	27	1.0000		
71.5	280	280	1.0000		
72.5	63	63	1.0000		
73.5					
74.5					
75.5					
76.5	277	277	1.0000		
77.5					


JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 366.00 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1952-2018 EXPERIENCE
1900-2018 PLACEMENTS
IOWA 75-R4
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
20
40
60
80
100
120
140
160

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1952-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	115,160,786	41,987	0.0004	0.9996	100.00
0.5	114,177,995	151,100	0.0013	0.9987	99.96
1.5	113,013,820	63,224	0.0006	0.9994	99.83
2.5	112,268,058	83,560	0.0007	0.9993	99.78
3.5	111,918,821	35,337	0.0003	0.9997	99.70
4.5	111,542,401	54,437	0.0005	0.9995	99.67
5.5	111,532,736	84,507	0.0008	0.9992	99.62
6.5	110,955,061	35,444	0.0003	0.9997	99.55
7.5	110,225,802	41,158	0.0004	0.9996	99.51
8.5	110,037,554	62,118	0.0006	0.9994	99.48
9.5	109,276,450	46,636	0.0004	0.9996	99.42
10.5	108,931,094	45,535	0.0004	0.9996	99.38
11.5	108,781,425	69,486	0.0006	0.9994	99.34
12.5	108,427,114	37,034	0.0003	0.9997	99.27
13.5	108,159,112	31,965	0.0003	0.9997	99.24
14.5	108,010,276	26,895	0.0002	0.9998	99.21
15.5	106,788,612	24,636	0.0002	0.9998	99.19
16.5	100,744,145	30,490	0.0003	0.9997	99.16
17.5	95,961,018	16,583	0.0002	0.9998	99.13
18.5	93,771,585	36,603	0.0004	0.9996	99.12
19.5	93,182,745	11,357	0.0001	0.9999	99.08
20.5	86,595,252	45,775	0.0005	0.9995	99.06
21.5	81,674,742	18,606	0.0002	0.9998	99.01
22.5	75,436,534	4,810	0.0001	0.9999	98.99
23.5	63,250,754	6,627	0.0001	0.9999	98.98
24.5	56,646,090	14,830	0.0003	0.9997	98.97
25.5	52,513,521	3,681	0.0001	0.9999	98.95
26.5	48,772,227	5,391	0.0001	0.9999	98.94
27.5	44,598,949	6,633	0.0001	0.9999	98.93
28.5	41,824,087	2,828	0.0001	0.9999	98.91
29.5	38,166,501	2,247	0.0001	0.9999	98.91
30.5	33,955,941	5,233	0.0002	0.9998	98.90
31.5	31,243,940	14,637	0.0005	0.9995	98.89
32.5	28,446,690	13,354	0.0005	0.9995	98.84
33.5	25,865,309	1,862	0.0001	0.9999	98.79
34.5	24,382,674	2,128	0.0001	0.9999	98.79
35.5	23,207,994	2,734	0.0001	0.9999	98.78
36.5	21,958,135	11,072	0.0005	0.9995	98.77
37.5	20,552,214	4,335	0.0002	0.9998	98.72
38.5	19,387,624	4,420	0.0002	0.9998	98.70

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1952-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	17,604,891	1,027	0.0001	0.9999	98.67
40.5	16,355,612	3,084	0.0002	0.9998	98.67
41.5	15,432,372	2,547	0.0002	0.9998	98.65
42.5	13,489,978	9,334	0.0007	0.9993	98.63
43.5	12,135,290	4,996	0.0004	0.9996	98.56
44.5	10,127,444	6,591	0.0007	0.9993	98.52
45.5	7,769,811	11,663	0.0015	0.9985	98.46
46.5	7,399,820	30,315	0.0041	0.9959	98.31
47.5	6,792,044	1,267	0.0002	0.9998	97.91
48.5	6,150,506	7,364	0.0012	0.9988	97.89
49.5	5,600,370	3,560	0.0006	0.9994	97.77
50.5	4,857,239	3,509	0.0007	0.9993	97.71
51.5	4,448,054	8,783	0.0020	0.9980	97.64
52.5	3,970,997	6,337	0.0016	0.9984	97.45
53.5	3,795,382	3,576	0.0009	0.9991	97.29
54.5	3,641,870	6,784	0.0019	0.9981	97.20
55.5	3,311,843	1,426	0.0004	0.9996	97.02
56.5	2,979,454	376	0.0001	0.9999	96.98
57.5	2,743,079	2,630	0.0010	0.9990	96.97
58.5	2,504,418	1,235	0.0005	0.9995	96.87
59.5	2,276,013	1,479	0.0006	0.9994	96.83
60.5	2,030,200	399	0.0002	0.9998	96.76
61.5	1,418,794	347	0.0002	0.9998	96.74
62.5	1,250,079	641	0.0005	0.9995	96.72
63.5	1,119,232	1,289	0.0012	0.9988	96.67
64.5	1,009,190	2,199	0.0022	0.9978	96.56
65.5	960,867	334	0.0003	0.9997	96.35
66.5	939,895	234	0.0002	0.9998	96.31
67.5	896,682	5,694	0.0064	0.9936	96.29
68.5	890,969	2,181	0.0024	0.9976	95.68
69.5	871,633	3,492	0.0040	0.9960	95.44
70.5	861,977	2,510	0.0029	0.9971	95.06
71.5	852,148	1,432	0.0017	0.9983	94.79
72.5	847,508	80	0.0001	0.9999	94.63
73.5	846,666	16	0.0000	1.0000	94.62
74.5	845,533	1	0.0000	1.0000	94.62
75.5	845,370	1,348	0.0016	0.9984	94.62
76.5	835,522	208	0.0002	0.9998	94.46
77.5	822,259	1,763	0.0021	0.9979	94.44
78.5	801,218	342	0.0004	0.9996	94.24

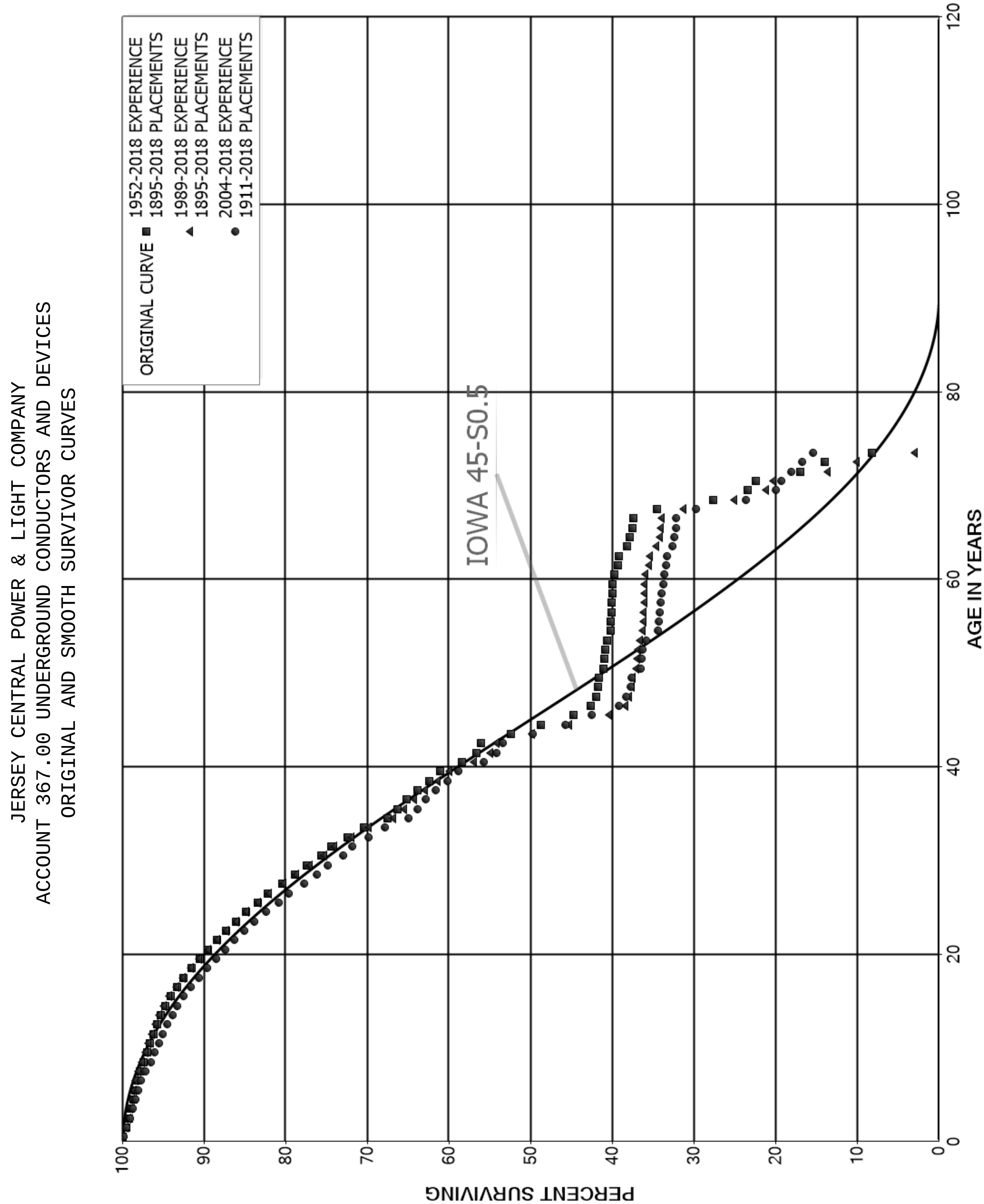
JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1952-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	781,801	327	0.0004	0.9996	94.20
80.5	763,976	5,042	0.0066	0.9934	94.16
81.5	736,704		0.0000	1.0000	93.54
82.5	677,620		0.0000	1.0000	93.54
83.5	654,008		0.0000	1.0000	93.54
84.5	642,525		0.0000	1.0000	93.54
85.5	634,556	6,028	0.0095	0.9905	93.54
86.5	620,802	5,647	0.0091	0.9909	92.65
87.5	504,234	5,395	0.0107	0.9893	91.81
88.5	386,021	109	0.0003	0.9997	90.82
89.5	248,751	101	0.0004	0.9996	90.80
90.5	242,514	7,503	0.0309	0.9691	90.76
91.5	233,635		0.0000	1.0000	87.95
92.5	233,558		0.0000	1.0000	87.95
93.5	233,558		0.0000	1.0000	87.95
94.5	233,558		0.0000	1.0000	87.95
95.5	223,856		0.0000	1.0000	87.95
96.5	223,856	1,025	0.0046	0.9954	87.95
97.5	204,202		0.0000	1.0000	87.55
98.5	201,730	21	0.0001	0.9999	87.55
99.5	201,710	24	0.0001	0.9999	87.54
100.5	201,685	14	0.0001	0.9999	87.53
101.5	201,671		0.0000	1.0000	87.53
102.5	201,671		0.0000	1.0000	87.53
103.5	201,671		0.0000	1.0000	87.53
104.5	201,671		0.0000	1.0000	87.53
105.5	5,462		0.0000	1.0000	87.53
106.5	5,462		0.0000	1.0000	87.53
107.5	2,069		0.0000	1.0000	87.53
108.5	2,069		0.0000	1.0000	87.53
109.5	2,069	1,172	0.5666	0.4334	87.53
110.5	897	897	1.0000		37.93
111.5					


JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE
1952-2018 EXPERIENCE
1895-2018 PLACEMENTS
1989-2018 EXPERIENCE
1895-2018 PLACEMENTS
2004-2018 EXPERIENCE
1911-2018 PLACEMENTS
IOWA 45-S0.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
120

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1952-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	654,380,406	681,035	0.0010	0.9990	100.00
0.5	625,344,089	2,696,759	0.0043	0.9957	99.90
1.5	592,993,011	1,632,661	0.0028	0.9972	99.47
2.5	553,683,122	1,345,945	0.0024	0.9976	99.19
3.5	498,921,266	1,421,781	0.0028	0.9972	98.95
4.5	475,611,494	1,177,328	0.0025	0.9975	98.67
5.5	458,802,276	1,077,471	0.0023	0.9977	98.42
6.5	413,958,379	1,470,415	0.0036	0.9964	98.19
7.5	396,128,285	1,912,498	0.0048	0.9952	97.84
8.5	379,191,331	1,555,865	0.0041	0.9959	97.37
9.5	357,065,022	1,424,391	0.0040	0.9960	96.97
10.5	331,787,781	1,318,085	0.0040	0.9960	96.59
11.5	323,168,067	1,499,189	0.0046	0.9954	96.20
12.5	302,343,771	1,519,387	0.0050	0.9950	95.76
13.5	281,237,607	1,595,101	0.0057	0.9943	95.27
14.5	269,132,885	1,862,529	0.0069	0.9931	94.73
15.5	256,974,532	2,205,932	0.0086	0.9914	94.08
16.5	244,719,936	2,144,305	0.0088	0.9912	93.27
17.5	229,587,712	2,340,208	0.0102	0.9898	92.45
18.5	216,511,263	2,317,494	0.0107	0.9893	91.51
19.5	203,023,601	2,397,474	0.0118	0.9882	90.53
20.5	183,221,304	2,260,685	0.0123	0.9877	89.46
21.5	168,808,076	2,031,788	0.0120	0.9880	88.36
22.5	157,023,914	2,120,952	0.0135	0.9865	87.29
23.5	146,855,252	2,180,986	0.0149	0.9851	86.12
24.5	137,279,818	2,265,402	0.0165	0.9835	84.84
25.5	121,813,838	1,870,719	0.0154	0.9846	83.44
26.5	108,015,015	2,251,486	0.0208	0.9792	82.16
27.5	90,683,004	1,760,079	0.0194	0.9806	80.44
28.5	80,483,851	1,533,987	0.0191	0.9809	78.88
29.5	69,371,658	1,535,805	0.0221	0.9779	77.38
30.5	56,527,881	959,353	0.0170	0.9830	75.67
31.5	49,406,238	1,327,172	0.0269	0.9731	74.38
32.5	43,034,980	1,210,304	0.0281	0.9719	72.38
33.5	36,148,741	1,433,377	0.0397	0.9603	70.35
34.5	32,532,997	615,481	0.0189	0.9811	67.56
35.5	29,924,436	488,427	0.0163	0.9837	66.28
36.5	27,022,346	566,637	0.0210	0.9790	65.20
37.5	24,027,641	543,396	0.0226	0.9774	63.83
38.5	21,570,838	453,859	0.0210	0.9790	62.39

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1952-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	19,006,491	839,545	0.0442	0.9558	61.07
40.5	16,193,645	477,671	0.0295	0.9705	58.38
41.5	14,128,297	156,013	0.0110	0.9890	56.65
42.5	12,662,556	826,590	0.0653	0.9347	56.03
43.5	11,113,345	778,428	0.0700	0.9300	52.37
44.5	9,115,962	734,606	0.0806	0.9194	48.70
45.5	7,296,228	355,329	0.0487	0.9513	44.78
46.5	6,618,025	91,992	0.0139	0.9861	42.60
47.5	5,534,959	41,165	0.0074	0.9926	42.01
48.5	5,348,873	13,961	0.0026	0.9974	41.69
49.5	5,037,073	68,664	0.0136	0.9864	41.58
50.5	4,340,656	7,822	0.0018	0.9982	41.02
51.5	3,986,000	15,314	0.0038	0.9962	40.94
52.5	3,718,313	14,130	0.0038	0.9962	40.79
53.5	3,555,541	39,370	0.0111	0.9889	40.63
54.5	3,360,653	3,143	0.0009	0.9991	40.18
55.5	3,226,677	7,062	0.0022	0.9978	40.14
56.5	3,110,591	2,846	0.0009	0.9991	40.06
57.5	2,968,231	3,318	0.0011	0.9989	40.02
58.5	2,938,284	4,653	0.0016	0.9984	39.97
59.5	2,972,528	16,195	0.0054	0.9946	39.91
60.5	2,930,607	31,900	0.0109	0.9891	39.69
61.5	2,882,675	9,187	0.0032	0.9968	39.26
62.5	2,828,723	68,046	0.0241	0.9759	39.14
63.5	2,689,932	28,136	0.0105	0.9895	38.20
64.5	2,601,379	16,431	0.0063	0.9937	37.80
65.5	2,553,250	9,655	0.0038	0.9962	37.56
66.5	2,528,083	197,234	0.0780	0.9220	37.42
67.5	2,299,219	457,593	0.1990	0.8010	34.50
68.5	1,841,861	283,635	0.1540	0.8460	27.63
69.5	1,546,755	63,007	0.0407	0.9593	23.38
70.5	61,581	15,045	0.2443	0.7557	22.42
71.5	45,933	8,030	0.1748	0.8252	16.95
72.5	37,991	15,759	0.4148	0.5852	13.98
73.5	22,331	5,063	0.2267	0.7733	8.18
74.5	16,420	616	0.0375	0.9625	6.33
75.5	15,805	128	0.0081	0.9919	6.09
76.5	15,789	1	0.0000	1.0000	6.04
77.5	15,791	3	0.0002	0.9998	6.04
78.5	15,788	177	0.0112	0.9888	6.04

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1952-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	15,781	144	0.0091	0.9909	5.97
80.5	15,705	121	0.0077	0.9923	5.92
81.5	15,584	8	0.0005	0.9995	5.87
82.5	15,576	45	0.0029	0.9971	5.87
83.5	15,532	0	0.0000	1.0000	5.85
84.5	15,532		0.0000	1.0000	5.85
85.5	15,532	7,558	0.4866	0.5134	5.85
86.5	7,974	3,187	0.3997	0.6003	3.00
87.5	4,786	1,598	0.3339	0.6661	1.80
88.5	3,188	3,188	1.0000		1.20
89.5					
90.5					
91.5					
92.5					
93.5					
94.5					
95.5					
96.5					
97.5					
98.5					
99.5					
100.5					
101.5					
102.5					
103.5					
104.5					
105.5	7	7	1.0000		
106.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	567,177,954	608,251	0.0011	0.9989	100.00
0.5	553,578,645	2,151,295	0.0039	0.9961	99.89
1.5	532,057,847	1,492,729	0.0028	0.9972	99.50
2.5	501,192,260	1,176,494	0.0023	0.9977	99.23
3.5	453,044,846	1,227,619	0.0027	0.9973	98.99
4.5	433,379,202	980,226	0.0023	0.9977	98.72
5.5	419,680,331	976,529	0.0023	0.9977	98.50
6.5	377,780,656	1,335,282	0.0035	0.9965	98.27
7.5	362,823,891	1,713,026	0.0047	0.9953	97.92
8.5	346,562,489	1,343,572	0.0039	0.9961	97.46
9.5	328,084,856	1,285,235	0.0039	0.9961	97.08
10.5	305,184,582	1,200,901	0.0039	0.9961	96.70
11.5	298,450,394	1,422,520	0.0048	0.9952	96.32
12.5	280,525,290	1,414,002	0.0050	0.9950	95.86
13.5	261,502,983	1,531,395	0.0059	0.9941	95.38
14.5	252,286,482	1,794,171	0.0071	0.9929	94.82
15.5	243,707,129	2,114,585	0.0087	0.9913	94.15
16.5	232,947,602	2,075,373	0.0089	0.9911	93.33
17.5	219,188,879	2,296,993	0.0105	0.9895	92.50
18.5	207,255,532	2,289,842	0.0110	0.9890	91.53
19.5	195,112,654	2,381,869	0.0122	0.9878	90.52
20.5	176,532,829	2,204,501	0.0125	0.9875	89.41
21.5	162,937,528	2,007,976	0.0123	0.9877	88.30
22.5	151,555,565	2,108,417	0.0139	0.9861	87.21
23.5	141,600,356	2,166,933	0.0153	0.9847	86.00
24.5	132,270,818	2,251,619	0.0170	0.9830	84.68
25.5	117,026,348	1,844,991	0.0158	0.9842	83.24
26.5	103,448,002	2,214,523	0.0214	0.9786	81.93
27.5	86,428,204	1,737,899	0.0201	0.9799	80.17
28.5	76,488,775	1,515,836	0.0198	0.9802	78.56
29.5	65,740,155	1,527,666	0.0232	0.9768	77.00
30.5	53,108,345	919,120	0.0173	0.9827	75.21
31.5	46,375,337	1,308,922	0.0282	0.9718	73.91
32.5	40,071,536	1,188,563	0.0297	0.9703	71.83
33.5	33,279,117	1,421,302	0.0427	0.9573	69.70
34.5	29,740,521	613,175	0.0206	0.9794	66.72
35.5	27,191,530	476,218	0.0175	0.9825	65.34
36.5	24,325,195	503,994	0.0207	0.9793	64.20
37.5	21,435,865	538,489	0.0251	0.9749	62.87
38.5	18,997,526	448,276	0.0236	0.9764	61.29

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,452,254	834,024	0.0507	0.9493	59.84
40.5	13,663,443	472,529	0.0346	0.9654	56.81
41.5	11,622,370	154,900	0.0133	0.9867	54.85
42.5	10,132,131	823,297	0.0813	0.9187	54.11
43.5	8,581,593	775,202	0.0903	0.9097	49.72
44.5	6,564,833	710,963	0.1083	0.8917	45.23
45.5	7,149,534	354,835	0.0496	0.9504	40.33
46.5	6,476,579	89,775	0.0139	0.9861	38.33
47.5	5,404,027	40,346	0.0075	0.9925	37.80
48.5	5,221,460	13,946	0.0027	0.9973	37.51
49.5	4,930,104	68,477	0.0139	0.9861	37.41
50.5	4,235,859	7,622	0.0018	0.9982	36.89
51.5	3,884,093	14,092	0.0036	0.9964	36.83
52.5	3,621,246	13,809	0.0038	0.9962	36.69
53.5	3,471,414	39,337	0.0113	0.9887	36.55
54.5	3,281,856	3,143	0.0010	0.9990	36.14
55.5	3,160,462	6,466	0.0020	0.9980	36.10
56.5	3,057,352	2,846	0.0009	0.9991	36.03
57.5	2,930,427	2,903	0.0010	0.9990	36.00
58.5	2,907,579	3,908	0.0013	0.9987	35.96
59.5	2,955,816	7,459	0.0025	0.9975	35.91
60.5	2,911,083	31,082	0.0107	0.9893	35.82
61.5	2,864,700	8,803	0.0031	0.9969	35.44
62.5	2,811,132	67,770	0.0241	0.9759	35.33
63.5	2,672,616	28,136	0.0105	0.9895	34.48
64.5	2,584,064	16,145	0.0062	0.9938	34.12
65.5	2,536,220	8,702	0.0034	0.9966	33.90
66.5	2,512,006	197,234	0.0785	0.9215	33.79
67.5	2,283,155	457,503	0.2004	0.7996	31.13
68.5	1,825,902	283,635	0.1553	0.8447	24.90
69.5	1,530,796	63,007	0.0412	0.9588	21.03
70.5	45,621	15,045	0.3298	0.6702	20.16
71.5	29,974	8,030	0.2679	0.7321	13.51
72.5	22,032	15,759	0.7153	0.2847	9.89
73.5	6,371	4,992	0.7835	0.2165	2.82
74.5	531	488	0.9185	0.0815	0.61
75.5	15,805	128	0.0081	0.9919	0.05
76.5	15,789	1	0.0000	1.0000	0.05
77.5	15,791	3	0.0002	0.9998	0.05
78.5	15,788	177	0.0112	0.9888	0.05

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2018 EXPERIENCE BAND 1989-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	15,781	144	0.0091	0.9909	0.05
80.5	15,705	121	0.0077	0.9923	0.05
81.5	15,584	8	0.0005	0.9995	0.05
82.5	15,576	45	0.0029	0.9971	0.05
83.5	15,532	0	0.0000	1.0000	0.05
84.5	15,532		0.0000	1.0000	0.05
85.5	15,532	7,558	0.4866	0.5134	0.05
86.5	7,974	3,187	0.3997	0.6003	0.02
87.5	4,786	1,598	0.3339	0.6661	0.01
88.5	3,188	3,188	1.0000		0.01
89.5					
90.5					
91.5					
92.5					
93.5					
94.5					
95.5					
96.5					
97.5					
98.5					
99.5					
100.5					
101.5					
102.5					
103.5					
104.5					
105.5	7	7	1.0000		
106.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 2004-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	374,759,719	489,297	0.0013	0.9987	100.00
0.5	352,838,162	1,382,230	0.0039	0.9961	99.87
1.5	334,090,059	1,281,412	0.0038	0.9962	99.48
2.5	310,323,416	1,075,557	0.0035	0.9965	99.10
3.5	268,318,725	1,081,681	0.0040	0.9960	98.75
4.5	258,239,970	841,202	0.0033	0.9967	98.36
5.5	261,530,272	840,809	0.0032	0.9968	98.03
6.5	230,720,073	1,204,963	0.0052	0.9948	97.72
7.5	224,476,455	1,539,578	0.0069	0.9931	97.21
8.5	214,835,540	1,128,440	0.0053	0.9947	96.54
9.5	201,658,729	1,052,274	0.0052	0.9948	96.04
10.5	192,219,359	976,452	0.0051	0.9949	95.53
11.5	198,305,785	1,230,492	0.0062	0.9938	95.05
12.5	196,356,073	1,189,997	0.0061	0.9939	94.46
13.5	186,119,281	1,282,789	0.0069	0.9931	93.89
14.5	186,663,428	1,580,402	0.0085	0.9915	93.24
15.5	189,363,869	1,796,526	0.0095	0.9905	92.45
16.5	185,736,027	1,879,965	0.0101	0.9899	91.57
17.5	177,807,146	2,113,359	0.0119	0.9881	90.65
18.5	170,674,993	2,063,817	0.0121	0.9879	89.57
19.5	160,536,459	2,033,236	0.0127	0.9873	88.49
20.5	143,789,377	1,823,973	0.0127	0.9873	87.37
21.5	132,335,736	1,768,528	0.0134	0.9866	86.26
22.5	123,082,459	1,840,139	0.0150	0.9850	85.10
23.5	115,864,418	1,958,807	0.0169	0.9831	83.83
24.5	109,922,275	2,053,007	0.0187	0.9813	82.41
25.5	96,672,919	1,569,662	0.0162	0.9838	80.88
26.5	84,782,680	1,955,171	0.0231	0.9769	79.56
27.5	70,264,170	1,413,643	0.0201	0.9799	77.73
28.5	62,176,247	1,107,190	0.0178	0.9822	76.16
29.5	53,879,153	1,308,361	0.0243	0.9757	74.81
30.5	44,112,835	709,149	0.0161	0.9839	72.99
31.5	38,372,485	1,081,157	0.0282	0.9718	71.82
32.5	33,250,355	926,695	0.0279	0.9721	69.79
33.5	27,528,797	1,161,208	0.0422	0.9578	67.85
34.5	25,228,619	434,576	0.0172	0.9828	64.99
35.5	23,761,794	368,090	0.0155	0.9845	63.87
36.5	21,561,473	434,849	0.0202	0.9798	62.88
37.5	19,003,987	458,150	0.0241	0.9759	61.61
38.5	16,787,855	368,365	0.0219	0.9781	60.12

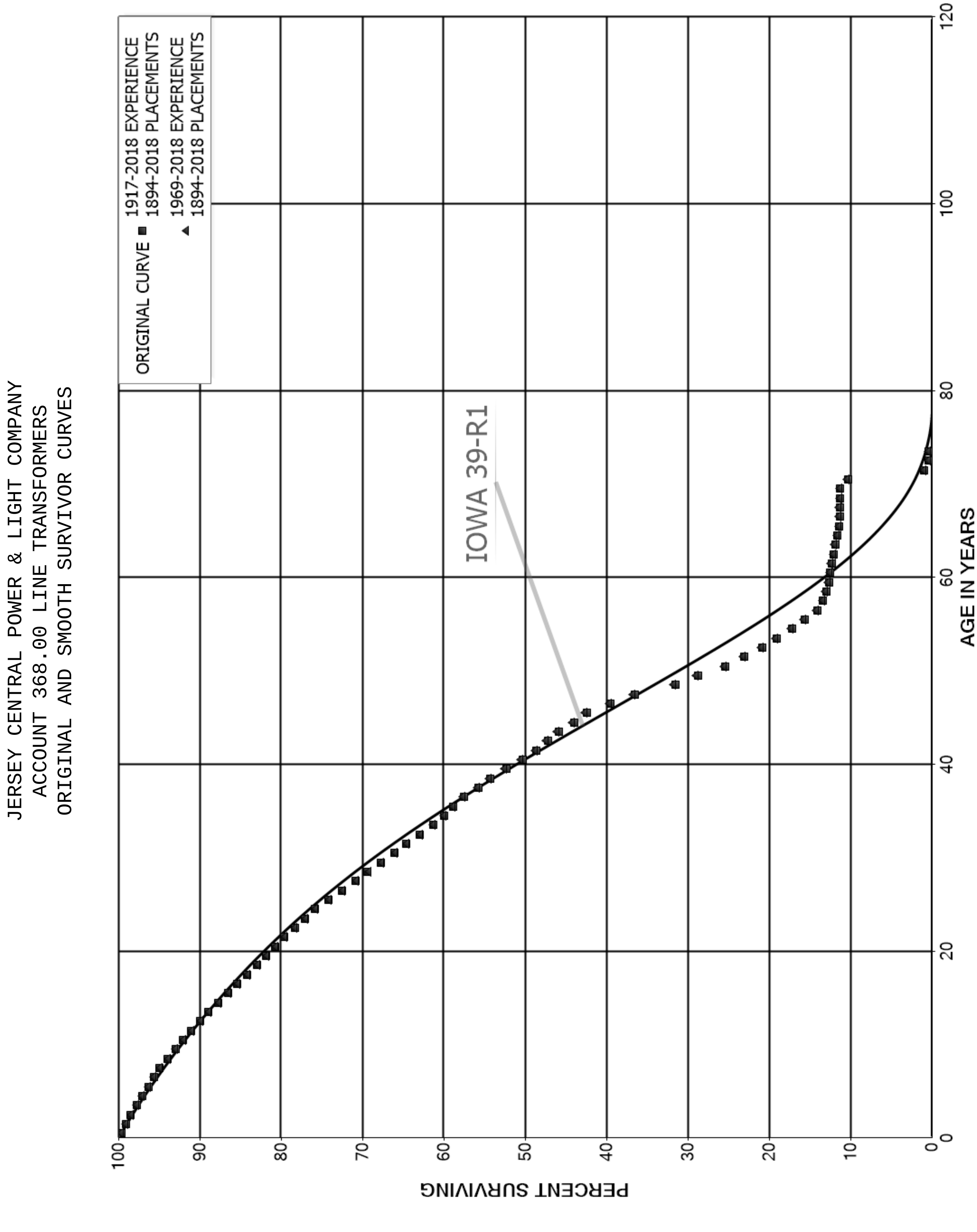
JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 2004-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	14,466,752	745,954	0.0516	0.9484	58.81
40.5	11,895,954	346,944	0.0292	0.9708	55.77
41.5	10,089,944	139,163	0.0138	0.9862	54.15
42.5	8,754,731	603,723	0.0690	0.9310	53.40
43.5	7,643,224	621,715	0.0813	0.9187	49.72
44.5	5,902,972	406,234	0.0688	0.9312	45.67
45.5	4,454,983	350,984	0.0788	0.9212	42.53
46.5	3,800,775	87,195	0.0229	0.9771	39.18
47.5	2,768,778	37,700	0.0136	0.9864	38.28
48.5	2,658,408	12,608	0.0047	0.9953	37.76
49.5	2,409,420	66,988	0.0278	0.9722	37.58
50.5	1,746,797	6,480	0.0037	0.9963	36.54
51.5	1,408,008	5,500	0.0039	0.9961	36.40
52.5	1,173,325	13,593	0.0116	0.9884	36.26
53.5	1,010,988	39,196	0.0388	0.9612	35.84
54.5	828,036	2,789	0.0034	0.9966	34.45
55.5	696,531	3,010	0.0043	0.9957	34.33
56.5	585,300	1,699	0.0029	0.9971	34.18
57.5	443,924	2,097	0.0047	0.9953	34.08
58.5	414,429	2,091	0.0050	0.9950	33.92
59.5	327,382	1,317	0.0040	0.9960	33.75
60.5	2,780,178	22,783	0.0082	0.9918	33.62
61.5	2,741,250	4,926	0.0018	0.9982	33.34
62.5	2,691,457	50,684	0.0188	0.9812	33.28
63.5	2,569,877	24,668	0.0096	0.9904	32.65
64.5	2,484,684	12,163	0.0049	0.9951	32.34
65.5	2,440,700	3,192	0.0013	0.9987	32.18
66.5	2,421,911	184,681	0.0763	0.9237	32.14
67.5	2,205,540	449,718	0.2039	0.7961	29.69
68.5	1,755,920	271,004	0.1543	0.8457	23.64
69.5	1,473,329	49,248	0.0334	0.9666	19.99
70.5	1,819	117	0.0646	0.9354	19.32
71.5	1,063	78	0.0736	0.9264	18.07
72.5	1,063	88	0.0832	0.9168	16.74
73.5	1,062	196	0.1843	0.8157	15.35
74.5					12.52


JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 368.00 LINE TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE
1917-2018 EXPERIENCE
1894-2018 PLACEMENTS
1969-2018 EXPERIENCE
1894-2018 PLACEMENTS
IOWA 39-R1
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
0
20
40
60
80
100
120

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1894-2018 EXPERIENCE BAND 1917-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,050,868,608	4,213,862	0.0040	0.9960	100.00
0.5	1,021,299,226	5,118,490	0.0050	0.9950	99.60
1.5	991,034,825	6,435,158	0.0065	0.9935	99.10
2.5	952,229,946	6,614,736	0.0069	0.9931	98.46
3.5	850,031,944	5,995,868	0.0071	0.9929	97.77
4.5	854,187,332	6,664,387	0.0078	0.9922	97.08
5.5	854,893,912	6,073,097	0.0071	0.9929	96.33
6.5	778,542,640	5,931,767	0.0076	0.9924	95.64
7.5	749,350,774	7,443,613	0.0099	0.9901	94.91
8.5	710,492,832	7,299,620	0.0103	0.9897	93.97
9.5	672,068,869	7,130,629	0.0106	0.9894	93.00
10.5	617,357,760	6,169,234	0.0100	0.9900	92.02
11.5	590,267,010	7,165,281	0.0121	0.9879	91.10
12.5	549,262,604	6,611,692	0.0120	0.9880	89.99
13.5	491,761,959	6,539,544	0.0133	0.9867	88.91
14.5	441,049,128	6,082,516	0.0138	0.9862	87.73
15.5	404,138,192	5,419,989	0.0134	0.9866	86.52
16.5	378,121,625	5,178,525	0.0137	0.9863	85.36
17.5	351,219,254	5,398,714	0.0154	0.9846	84.19
18.5	328,719,295	4,216,259	0.0128	0.9872	82.89
19.5	317,516,454	4,276,031	0.0135	0.9865	81.83
20.5	300,482,133	4,233,304	0.0141	0.9859	80.73
21.5	282,192,587	4,478,517	0.0159	0.9841	79.59
22.5	265,348,597	4,364,243	0.0164	0.9836	78.33
23.5	245,934,470	3,991,889	0.0162	0.9838	77.04
24.5	226,989,060	4,788,464	0.0211	0.9789	75.79
25.5	209,110,224	4,733,099	0.0226	0.9774	74.19
26.5	192,822,801	4,310,588	0.0224	0.9776	72.51
27.5	177,433,619	3,847,535	0.0217	0.9783	70.89
28.5	160,327,756	3,725,613	0.0232	0.9768	69.35
29.5	140,289,591	3,398,176	0.0242	0.9758	67.74
30.5	121,934,456	2,797,372	0.0229	0.9771	66.10
31.5	104,813,800	2,701,774	0.0258	0.9742	64.58
32.5	88,068,776	2,233,271	0.0254	0.9746	62.92
33.5	75,896,547	1,661,568	0.0219	0.9781	61.32
34.5	66,999,936	1,296,333	0.0193	0.9807	59.98
35.5	60,598,883	1,358,776	0.0224	0.9776	58.82
36.5	55,859,127	1,731,869	0.0310	0.9690	57.50
37.5	51,853,356	1,368,797	0.0264	0.9736	55.72
38.5	49,105,460	1,752,687	0.0357	0.9643	54.25

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1894-2018 EXPERIENCE BAND 1917-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	44,927,600	1,734,822	0.0386	0.9614	52.31
40.5	40,252,721	1,362,501	0.0338	0.9662	50.29
41.5	36,398,150	1,036,225	0.0285	0.9715	48.59
42.5	32,631,774	971,812	0.0298	0.9702	47.21
43.5	30,618,518	1,199,330	0.0392	0.9608	45.80
44.5	24,903,786	935,500	0.0376	0.9624	44.01
45.5	20,866,958	1,427,297	0.0684	0.9316	42.35
46.5	17,786,135	1,313,213	0.0738	0.9262	39.46
47.5	14,788,586	2,032,053	0.1374	0.8626	36.54
48.5	12,171,375	1,060,218	0.0871	0.9129	31.52
49.5	10,937,411	1,293,478	0.1183	0.8817	28.78
50.5	9,635,706	882,838	0.0916	0.9084	25.37
51.5	8,754,233	823,480	0.0941	0.9059	23.05
52.5	7,936,381	694,742	0.0875	0.9125	20.88
53.5	7,245,516	706,339	0.0975	0.9025	19.05
54.5	6,562,712	598,849	0.0913	0.9087	17.19
55.5	5,967,197	592,822	0.0993	0.9007	15.63
56.5	5,644,737	282,049	0.0500	0.9500	14.07
57.5	5,363,298	153,363	0.0286	0.9714	13.37
58.5	5,214,261	140,403	0.0269	0.9731	12.99
59.5	5,072,576	74,234	0.0146	0.9854	12.64
60.5	5,004,381	58,896	0.0118	0.9882	12.45
61.5	4,956,702	112,313	0.0227	0.9773	12.31
62.5	4,847,151	71,292	0.0147	0.9853	12.03
63.5	4,779,224	103,505	0.0217	0.9783	11.85
64.5	4,677,973	84,798	0.0181	0.9819	11.59
65.5	4,593,244	28,015	0.0061	0.9939	11.38
66.5	4,567,318	8,946	0.0020	0.9980	11.31
67.5	4,559,343	10,082	0.0022	0.9978	11.29
68.5	4,549,431	10,880	0.0024	0.9976	11.27
69.5	4,541,544	366,396	0.0807	0.9193	11.24
70.5	4,176,432	3,814,325	0.9133	0.0867	10.33
71.5	362,174	191,967	0.5300	0.4700	0.90
72.5	170,449	23,566	0.1383	0.8617	0.42
73.5	34,763	9,370	0.2695	0.7305	0.36
74.5	26,048	2,764	0.1061	0.8939	0.27
75.5	23,919	5,185	0.2168	0.7832	0.24
76.5	18,883	4,483	0.2374	0.7626	0.19
77.5	14,615	1,675	0.1146	0.8854	0.14
78.5	13,221	1,566	0.1184	0.8816	0.13

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1894-2018 EXPERIENCE BAND 1917-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	12,481	2,496	0.2000	0.8000	0.11
80.5	10,029	742	0.0740	0.9260	0.09
81.5	9,266	1,519	0.1639	0.8361	0.08
82.5	7,808	1,223	0.1567	0.8433	0.07
83.5	6,632	1,139	0.1717	0.8283	0.06
84.5	5,789	1,223	0.2112	0.7888	0.05
85.5	4,567	645	0.1412	0.8588	0.04
86.5	3,922	1,245	0.3176	0.6824	0.03
87.5	2,676	882	0.3294	0.6706	0.02
88.5	1,795	112	0.0623	0.9377	0.01
89.5	1,683	95	0.0564	0.9436	0.01
90.5	1,588	30	0.0191	0.9809	0.01
91.5	1,557	389	0.2501	0.7499	0.01
92.5	1,168	956	0.8189	0.1811	0.01
93.5	335		0.0000	1.0000	0.00
94.5	335		0.0000	1.0000	0.00
95.5	335	103	0.3066	0.6934	0.00
96.5	232	109	0.4682	0.5318	0.00
97.5	124		0.0000	1.0000	0.00
98.5	124		0.0000	1.0000	0.00
99.5	124		0.0000	1.0000	0.00
100.5	124	124	1.0000		0.00
101.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1894-2018 EXPERIENCE BAND 1969-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	991,457,098	4,124,460	0.0042	0.9958	100.00
0.5	968,011,465	4,881,160	0.0050	0.9950	99.58
1.5	944,181,217	6,222,058	0.0066	0.9934	99.08
2.5	909,895,936	6,421,072	0.0071	0.9929	98.43
3.5	811,466,664	5,787,976	0.0071	0.9929	97.73
4.5	818,260,775	6,465,222	0.0079	0.9921	97.04
5.5	821,787,223	5,900,716	0.0072	0.9928	96.27
6.5	748,471,933	5,765,511	0.0077	0.9923	95.58
7.5	722,201,672	7,285,764	0.0101	0.9899	94.84
8.5	686,131,092	7,125,973	0.0104	0.9896	93.89
9.5	650,169,131	6,972,029	0.0107	0.9893	92.91
10.5	597,140,153	5,994,215	0.0100	0.9900	91.91
11.5	572,416,319	6,992,334	0.0122	0.9878	90.99
12.5	533,379,369	6,437,599	0.0121	0.9879	89.88
13.5	477,662,697	6,371,287	0.0133	0.9867	88.80
14.5	428,428,549	5,913,931	0.0138	0.9862	87.61
15.5	392,755,155	5,249,383	0.0134	0.9866	86.40
16.5	367,613,397	5,022,039	0.0137	0.9863	85.25
17.5	341,763,278	5,245,729	0.0153	0.9847	84.08
18.5	320,003,218	4,050,617	0.0127	0.9873	82.79
19.5	309,362,043	4,133,430	0.0134	0.9866	81.74
20.5	292,776,774	4,131,467	0.0141	0.9859	80.65
21.5	274,840,927	4,379,277	0.0159	0.9841	79.51
22.5	258,268,198	4,270,859	0.0165	0.9835	78.25
23.5	238,977,672	3,911,910	0.0164	0.9836	76.95
24.5	220,074,516	4,680,889	0.0213	0.9787	75.69
25.5	202,279,119	4,634,186	0.0229	0.9771	74.08
26.5	186,103,466	4,210,808	0.0226	0.9774	72.39
27.5	170,977,159	3,756,903	0.0220	0.9780	70.75
28.5	158,534,917	3,649,226	0.0230	0.9770	69.19
29.5	138,650,242	3,317,026	0.0239	0.9761	67.60
30.5	120,412,344	2,727,118	0.0226	0.9774	65.98
31.5	103,447,328	2,630,607	0.0254	0.9746	64.49
32.5	86,841,724	2,171,572	0.0250	0.9750	62.85
33.5	74,730,988	1,593,506	0.0213	0.9787	61.28
34.5	65,913,448	1,234,783	0.0187	0.9813	59.97
35.5	59,588,638	1,301,791	0.0218	0.9782	58.85
36.5	54,901,660	1,666,003	0.0303	0.9697	57.56
37.5	50,989,424	1,307,439	0.0256	0.9744	55.82
38.5	48,372,292	1,705,781	0.0353	0.9647	54.38

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1894-2018 EXPERIENCE BAND 1969-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	44,308,570	1,690,369	0.0381	0.9619	52.47
40.5	39,760,476	1,329,390	0.0334	0.9666	50.46
41.5	35,999,015	1,008,402	0.0280	0.9720	48.78
42.5	32,341,324	951,360	0.0294	0.9706	47.41
43.5	30,383,297	1,182,235	0.0389	0.9611	46.02
44.5	24,704,425	922,993	0.0374	0.9626	44.23
45.5	20,698,152	1,416,433	0.0684	0.9316	42.57
46.5	17,651,660	1,300,676	0.0737	0.9263	39.66
47.5	14,683,029	2,023,945	0.1378	0.8622	36.74
48.5	12,086,883	1,053,080	0.0871	0.9129	31.67
49.5	10,869,885	1,288,731	0.1186	0.8814	28.91
50.5	9,579,900	879,461	0.0918	0.9082	25.49
51.5	8,714,148	820,299	0.0941	0.9059	23.15
52.5	7,904,225	692,531	0.0876	0.9124	20.97
53.5	7,219,580	703,751	0.0975	0.9025	19.13
54.5	6,542,873	597,912	0.0914	0.9086	17.27
55.5	5,953,601	590,906	0.0993	0.9007	15.69
56.5	5,635,301	281,427	0.0499	0.9501	14.13
57.5	5,356,263	152,890	0.0285	0.9715	13.43
58.5	5,208,993	140,149	0.0269	0.9731	13.04
59.5	5,067,876	73,626	0.0145	0.9855	12.69
60.5	5,000,962	58,533	0.0117	0.9883	12.51
61.5	4,953,645	112,214	0.0227	0.9773	12.36
62.5	4,844,742	71,111	0.0147	0.9853	12.08
63.5	4,777,171	103,381	0.0216	0.9784	11.90
64.5	4,676,222	84,462	0.0181	0.9819	11.65
65.5	4,592,114	28,015	0.0061	0.9939	11.44
66.5	4,566,707	8,946	0.0020	0.9980	11.37
67.5	4,558,804	10,082	0.0022	0.9978	11.34
68.5	4,548,892	10,795	0.0024	0.9976	11.32
69.5	4,541,205	366,396	0.0807	0.9193	11.29
70.5	4,176,166	3,814,325	0.9134	0.0866	10.38
71.5	361,982	191,837	0.5300	0.4700	0.90
72.5	170,425	23,542	0.1381	0.8619	0.42
73.5	34,763	9,370	0.2695	0.7305	0.36
74.5	26,048	2,764	0.1061	0.8939	0.27
75.5	23,919	5,185	0.2168	0.7832	0.24
76.5	18,883	4,483	0.2374	0.7626	0.19
77.5	14,615	1,675	0.1146	0.8854	0.14
78.5	13,221	1,566	0.1184	0.8816	0.13

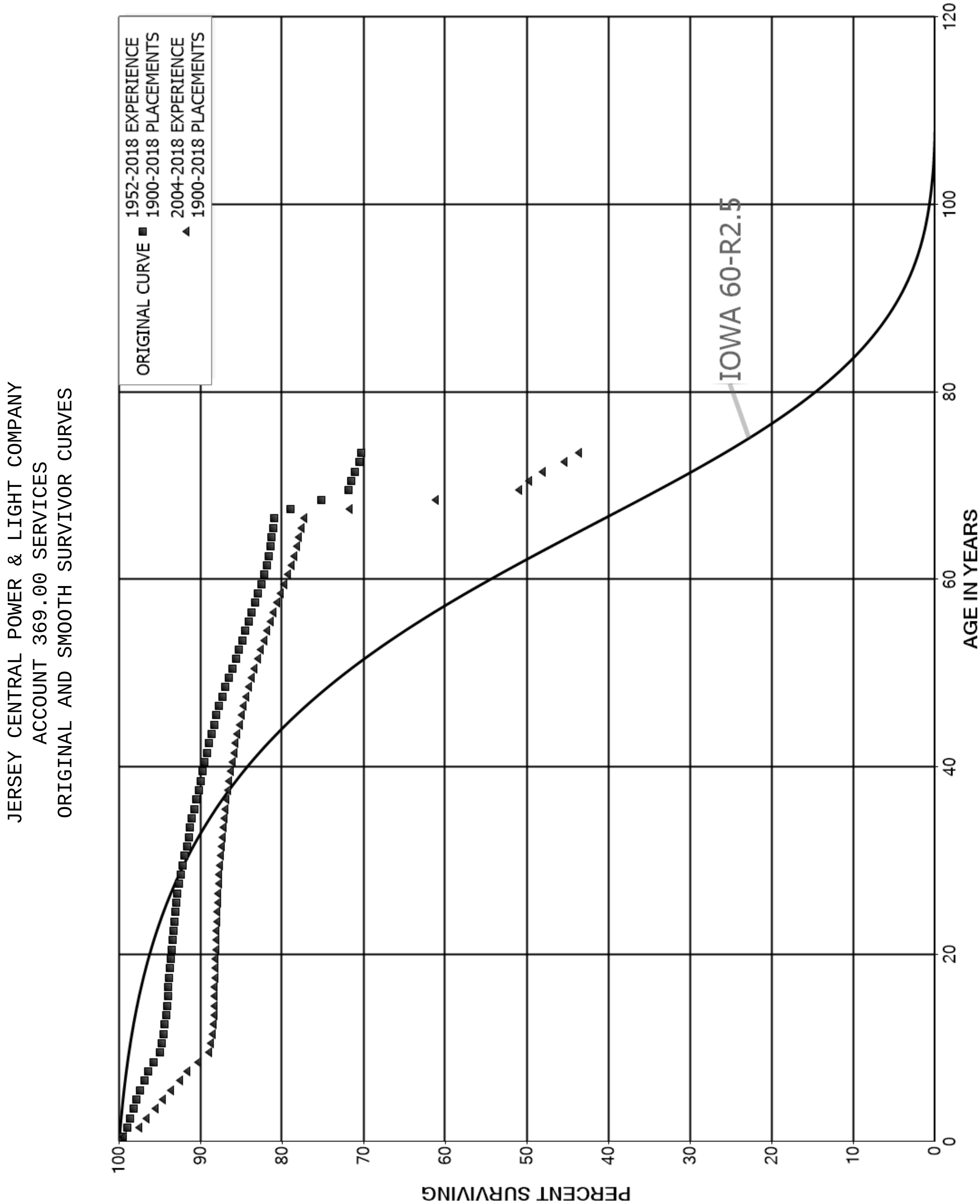
JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1894-2018 EXPERIENCE BAND 1969-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	12,481	2,496	0.2000	0.8000	0.11
80.5	10,029	742	0.0740	0.9260	0.09
81.5	9,266	1,519	0.1639	0.8361	0.08
82.5	7,808	1,223	0.1567	0.8433	0.07
83.5	6,632	1,139	0.1717	0.8283	0.06
84.5	5,789	1,223	0.2112	0.7888	0.05
85.5	4,567	645	0.1412	0.8588	0.04
86.5	3,922	1,245	0.3176	0.6824	0.03
87.5	2,676	882	0.3294	0.6706	0.02
88.5	1,795	112	0.0623	0.9377	0.01
89.5	1,683	95	0.0564	0.9436	0.01
90.5	1,588	30	0.0191	0.9809	0.01
91.5	1,557	389	0.2501	0.7499	0.01
92.5	1,168	956	0.8189	0.1811	0.01
93.5	335		0.0000	1.0000	0.00
94.5	335		0.0000	1.0000	0.00
95.5	335	103	0.3066	0.6934	0.00
96.5	232	109	0.4682	0.5318	0.00
97.5	124		0.0000	1.0000	0.00
98.5	124		0.0000	1.0000	0.00
99.5	124		0.0000	1.0000	0.00
100.5	124	124	1.0000		0.00
101.5					


JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 369.00 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 1952-2018 EXPERIENCE
1900-2018 PLACEMENTS
▲ 2004-2018 EXPERIENCE
1900-2018 PLACEMENTS
IOWA 60-R2.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1952-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	472,096,524	1,720,630	0.0036	0.9964	100.00
0.5	462,065,638	3,300,801	0.0071	0.9929	99.64
1.5	460,123,989	1,641,534	0.0036	0.9964	98.92
2.5	452,290,181	1,851,840	0.0041	0.9959	98.57
3.5	440,041,948	1,730,584	0.0039	0.9961	98.17
4.5	438,803,945	1,926,723	0.0044	0.9956	97.78
5.5	438,039,358	2,357,267	0.0054	0.9946	97.35
6.5	424,414,002	1,973,997	0.0047	0.9953	96.83
7.5	417,789,805	3,060,909	0.0073	0.9927	96.38
8.5	409,072,043	3,171,682	0.0078	0.9922	95.67
9.5	402,194,592	1,083,574	0.0027	0.9973	94.93
10.5	395,415,164	714,634	0.0018	0.9982	94.67
11.5	391,886,049	655,922	0.0017	0.9983	94.50
12.5	388,943,409	599,145	0.0015	0.9985	94.34
13.5	385,617,634	389,901	0.0010	0.9990	94.20
14.5	384,812,418	407,338	0.0011	0.9989	94.10
15.5	377,398,519	413,112	0.0011	0.9989	94.00
16.5	360,444,589	421,305	0.0012	0.9988	93.90
17.5	342,190,864	386,619	0.0011	0.9989	93.79
18.5	325,734,220	369,243	0.0011	0.9989	93.69
19.5	303,860,600	338,422	0.0011	0.9989	93.58
20.5	280,082,847	316,699	0.0011	0.9989	93.48
21.5	262,482,818	290,019	0.0011	0.9989	93.37
22.5	245,140,016	289,226	0.0012	0.9988	93.27
23.5	228,692,168	275,963	0.0012	0.9988	93.16
24.5	213,603,582	270,994	0.0013	0.9987	93.04
25.5	194,415,290	257,965	0.0013	0.9987	92.93
26.5	179,519,422	312,454	0.0017	0.9983	92.80
27.5	168,049,705	534,224	0.0032	0.9968	92.64
28.5	158,121,484	328,117	0.0021	0.9979	92.35
29.5	145,545,227	391,850	0.0027	0.9973	92.16
30.5	132,657,113	386,107	0.0029	0.9971	91.91
31.5	117,247,281	254,958	0.0022	0.9978	91.64
32.5	104,618,716	231,515	0.0022	0.9978	91.44
33.5	92,911,210	229,751	0.0025	0.9975	91.24
34.5	81,521,887	273,688	0.0034	0.9966	91.01
35.5	72,965,362	194,020	0.0027	0.9973	90.71
36.5	67,309,515	179,108	0.0027	0.9973	90.47
37.5	61,870,620	173,579	0.0028	0.9972	90.22
38.5	56,718,755	159,505	0.0028	0.9972	89.97

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1952-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	51,292,905	151,145	0.0029	0.9971	89.72
40.5	46,080,108	143,501	0.0031	0.9969	89.45
41.5	41,365,397	129,855	0.0031	0.9969	89.18
42.5	37,080,257	116,503	0.0031	0.9969	88.90
43.5	33,239,912	114,544	0.0034	0.9966	88.62
44.5	29,215,422	97,484	0.0033	0.9967	88.31
45.5	24,939,541	96,345	0.0039	0.9961	88.02
46.5	21,445,398	88,139	0.0041	0.9959	87.68
47.5	18,660,876	83,531	0.0045	0.9955	87.32
48.5	16,259,223	75,757	0.0047	0.9953	86.93
49.5	13,908,733	68,395	0.0049	0.9951	86.52
50.5	11,820,757	59,454	0.0050	0.9950	86.09
51.5	10,830,300	51,216	0.0047	0.9953	85.66
52.5	9,302,379	42,199	0.0045	0.9955	85.26
53.5	8,037,360	37,216	0.0046	0.9954	84.87
54.5	6,940,838	31,806	0.0046	0.9954	84.48
55.5	5,997,515	28,041	0.0047	0.9953	84.09
56.5	5,189,501	25,080	0.0048	0.9952	83.70
57.5	4,521,638	21,594	0.0048	0.9952	83.29
58.5	3,893,920	18,113	0.0047	0.9953	82.89
59.5	3,379,171	14,261	0.0042	0.9958	82.51
60.5	2,937,220	10,244	0.0035	0.9965	82.16
61.5	2,540,916	7,301	0.0029	0.9971	81.87
62.5	2,252,312	5,382	0.0024	0.9976	81.64
63.5	1,972,401	4,378	0.0022	0.9978	81.44
64.5	1,757,536	3,179	0.0018	0.9982	81.26
65.5	1,620,438	3,151	0.0019	0.9981	81.12
66.5	1,488,994	37,328	0.0251	0.9749	80.96
67.5	1,378,506	64,766	0.0470	0.9530	78.93
68.5	1,241,886	56,577	0.0456	0.9544	75.22
69.5	1,122,753	5,251	0.0047	0.9953	71.79
70.5	1,064,410	5,915	0.0056	0.9944	71.46
71.5	1,020,442	7,268	0.0071	0.9929	71.06
72.5	994,039	4,327	0.0044	0.9956	70.55
73.5	982,265	741	0.0008	0.9992	70.25
74.5	976,322	295	0.0003	0.9997	70.19
75.5	975,625	9	0.0000	1.0000	70.17
76.5	960,955	20	0.0000	1.0000	70.17
77.5	932,095	12	0.0000	1.0000	70.17
78.5	908,533	12	0.0000	1.0000	70.17

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 1952-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	906,967	409	0.0005	0.9995	70.17
80.5	902,869	19	0.0000	1.0000	70.14
81.5	897,058	27	0.0000	1.0000	70.14
82.5	892,108		0.0000	1.0000	70.13
83.5	887,798		0.0000	1.0000	70.13
84.5	886,656		0.0000	1.0000	70.13
85.5	885,540	6	0.0000	1.0000	70.13
86.5	884,969	12	0.0000	1.0000	70.13
87.5	884,295	13	0.0000	1.0000	70.13
88.5	883,514	16	0.0000	1.0000	70.13
89.5	883,261		0.0000	1.0000	70.13
90.5	883,189		0.0000	1.0000	70.13
91.5	883,094		0.0000	1.0000	70.13
92.5	882,925		0.0000	1.0000	70.13
93.5	882,925		0.0000	1.0000	70.13
94.5	882,925		0.0000	1.0000	70.13
95.5	882,925		0.0000	1.0000	70.13
96.5	882,925		0.0000	1.0000	70.13
97.5	882,925		0.0000	1.0000	70.13
98.5	882,925		0.0000	1.0000	70.13
99.5	882,925		0.0000	1.0000	70.13
100.5	882,925		0.0000	1.0000	70.13
101.5	882,925		0.0000	1.0000	70.13
102.5	882,925		0.0000	1.0000	70.13
103.5	882,925		0.0000	1.0000	70.13
104.5	882,925		0.0000	1.0000	70.13
105.5	882,925		0.0000	1.0000	70.13
106.5	882,925		0.0000	1.0000	70.13
107.5	882,925		0.0000	1.0000	70.13
108.5	882,925		0.0000	1.0000	70.13
109.5	882,925	412,568	0.4673	0.5327	70.13
110.5	470,357	470,357	1.0000		37.36
111.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 2004-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	101,917,934	757,690	0.0074	0.9926	100.00
0.5	100,319,921	1,905,063	0.0190	0.9810	99.26
1.5	108,568,225	994,151	0.0092	0.9908	97.37
2.5	118,152,180	1,271,868	0.0108	0.9892	96.48
3.5	118,915,186	1,187,672	0.0100	0.9900	95.44
4.5	136,057,924	1,415,850	0.0104	0.9896	94.49
5.5	156,649,115	1,859,571	0.0119	0.9881	93.51
6.5	159,578,541	1,526,307	0.0096	0.9904	92.40
7.5	169,383,708	2,533,093	0.0150	0.9850	91.51
8.5	177,100,026	2,472,241	0.0140	0.9860	90.14
9.5	185,467,265	660,778	0.0036	0.9964	88.88
10.5	197,922,276	312,133	0.0016	0.9984	88.57
11.5	209,439,084	277,845	0.0013	0.9987	88.43
12.5	217,961,523	234,294	0.0011	0.9989	88.31
13.5	224,315,468	40,007	0.0002	0.9998	88.22
14.5	236,048,242	69,189	0.0003	0.9997	88.20
15.5	241,442,030	80,260	0.0003	0.9997	88.17
16.5	239,842,986	105,798	0.0004	0.9996	88.14
17.5	234,307,629	99,138	0.0004	0.9996	88.11
18.5	229,621,702	112,606	0.0005	0.9995	88.07
19.5	219,222,958	105,921	0.0005	0.9995	88.03
20.5	203,914,179	103,933	0.0005	0.9995	87.98
21.5	191,932,076	88,314	0.0005	0.9995	87.94
22.5	180,007,846	95,082	0.0005	0.9995	87.90
23.5	168,724,553	90,860	0.0005	0.9995	87.85
24.5	159,080,865	94,326	0.0006	0.9994	87.80
25.5	145,083,513	88,037	0.0006	0.9994	87.75
26.5	134,909,160	89,362	0.0007	0.9993	87.70
27.5	127,851,610	95,111	0.0007	0.9993	87.64
28.5	122,142,934	102,145	0.0008	0.9992	87.58
29.5	113,792,943	108,227	0.0010	0.9990	87.50
30.5	105,480,970	118,909	0.0011	0.9989	87.42
31.5	93,840,616	112,918	0.0012	0.9988	87.32
32.5	84,116,502	105,570	0.0013	0.9987	87.22
33.5	74,924,955	114,209	0.0015	0.9985	87.11
34.5	65,998,091	110,076	0.0017	0.9983	86.97
35.5	59,688,634	99,426	0.0017	0.9983	86.83
36.5	56,023,197	103,843	0.0019	0.9981	86.68
37.5	52,248,236	103,305	0.0020	0.9980	86.52
38.5	48,470,384	101,104	0.0021	0.9979	86.35

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 2004-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	44,252,843	97,251	0.0022	0.9978	86.17
40.5	40,089,610	94,731	0.0024	0.9976	85.98
41.5	36,284,395	90,382	0.0025	0.9975	85.78
42.5	32,749,702	81,261	0.0025	0.9975	85.57
43.5	29,622,301	84,846	0.0029	0.9971	85.35
44.5	26,188,174	73,150	0.0028	0.9972	85.11
45.5	22,424,481	75,221	0.0034	0.9966	84.87
46.5	19,396,412	67,971	0.0035	0.9965	84.59
47.5	16,966,530	66,963	0.0039	0.9961	84.29
48.5	14,904,726	62,556	0.0042	0.9958	83.96
49.5	12,818,038	56,393	0.0044	0.9956	83.60
50.5	10,903,478	49,635	0.0046	0.9954	83.24
51.5	9,193,658	42,808	0.0047	0.9953	82.86
52.5	7,769,783	35,077	0.0045	0.9955	82.47
53.5	6,603,509	31,190	0.0047	0.9953	82.10
54.5	5,594,331	26,424	0.0047	0.9953	81.71
55.5	4,727,482	23,908	0.0051	0.9949	81.33
56.5	3,975,823	21,220	0.0053	0.9947	80.91
57.5	3,339,309	18,964	0.0057	0.9943	80.48
58.5	2,725,577	15,635	0.0057	0.9943	80.03
59.5	2,220,425	12,463	0.0056	0.9944	79.57
60.5	1,784,252	8,850	0.0050	0.9950	79.12
61.5	1,404,018	5,877	0.0042	0.9958	78.73
62.5	1,145,532	4,377	0.0038	0.9962	78.40
63.5	901,138	3,526	0.0039	0.9961	78.10
64.5	723,073	2,588	0.0036	0.9964	77.79
65.5	617,731	2,732	0.0044	0.9956	77.51
66.5	517,008	36,944	0.0715	0.9285	77.17
67.5	437,408	64,364	0.1471	0.8529	71.66
68.5	334,681	56,477	0.1687	0.8313	61.11
69.5	221,107	5,175	0.0234	0.9766	50.80
70.5	169,010	5,601	0.0331	0.9669	49.61
71.5	130,742	7,216	0.0552	0.9448	47.97
72.5	109,181	4,299	0.0394	0.9606	45.32
73.5	98,202	736	0.0075	0.9925	43.54
74.5	92,501	292	0.0032	0.9968	43.21
75.5	91,880		0.0000	1.0000	43.07
76.5	77,314		0.0000	1.0000	43.07
77.5	49,040		0.0000	1.0000	43.07
78.5	25,490		0.0000	1.0000	43.07

JERSEY CENTRAL POWER & LIGHT COMPANY

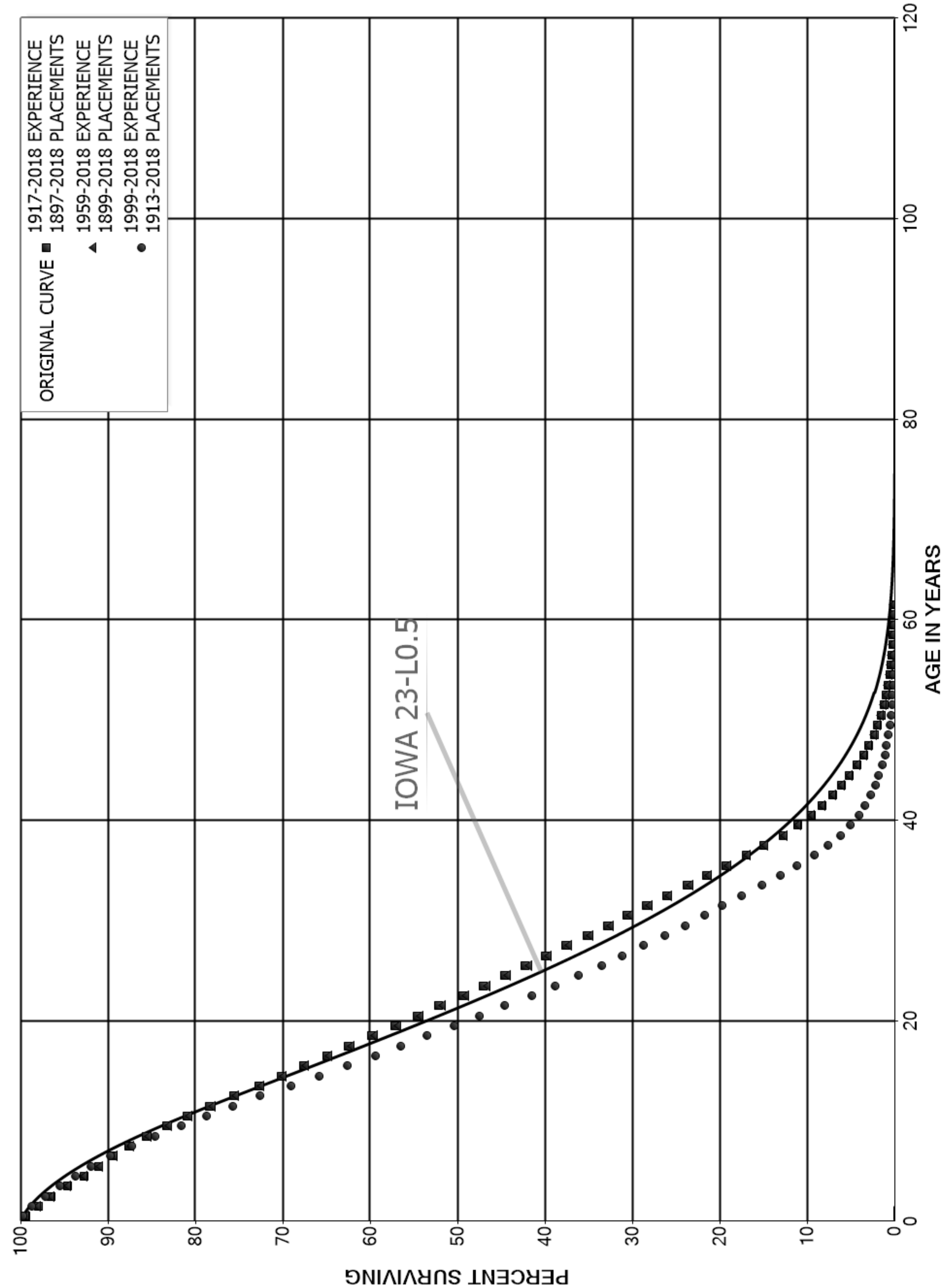
ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2018 EXPERIENCE BAND 2004-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	23,937	396	0.0166	0.9834	43.07
80.5	19,851		0.0000	1.0000	42.36
81.5	14,059		0.0000	1.0000	42.36
82.5	9,136		0.0000	1.0000	42.36
83.5	4,825		0.0000	1.0000	42.36
84.5	3,683		0.0000	1.0000	42.36
85.5	2,568		0.0000	1.0000	42.36
86.5	2,002		0.0000	1.0000	42.36
87.5	1,342		0.0000	1.0000	42.36
88.5	573		0.0000	1.0000	42.36
89.5	336		0.0000	1.0000	42.36
90.5	264		0.0000	1.0000	42.36
91.5	169		0.0000	1.0000	42.36
92.5					42.36
93.5					
94.5					
95.5					
96.5					
97.5					
98.5					
99.5					
100.5					
101.5					
102.5					
103.5	882,925		0.0000		
104.5	882,925		0.0000		
105.5	882,925		0.0000		
106.5	882,925		0.0000		
107.5	882,925		0.0000		
108.5	882,925		0.0000		
109.5	882,925	412,568	0.4673		
110.5	470,357	470,357	1.0000		
111.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 370.00 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1897-2018 EXPERIENCE BAND 1917-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	282,897,690	1,839,331	0.0065	0.9935	100.00
0.5	263,415,993	3,569,400	0.0136	0.9864	99.35
1.5	249,552,328	3,866,697	0.0155	0.9845	98.00
2.5	225,745,579	4,433,522	0.0196	0.9804	96.49
3.5	189,878,789	3,652,764	0.0192	0.9808	94.59
4.5	173,499,908	3,138,664	0.0181	0.9819	92.77
5.5	161,826,911	3,021,624	0.0187	0.9813	91.09
6.5	157,683,552	3,179,360	0.0202	0.9798	89.39
7.5	150,192,614	3,398,752	0.0226	0.9774	87.59
8.5	139,193,168	3,734,287	0.0268	0.9732	85.61
9.5	132,007,753	3,761,683	0.0285	0.9715	83.31
10.5	122,941,319	3,901,364	0.0317	0.9683	80.94
11.5	117,820,576	4,062,160	0.0345	0.9655	78.37
12.5	110,835,210	4,246,775	0.0383	0.9617	75.67
13.5	103,283,936	3,632,497	0.0352	0.9648	72.77
14.5	95,615,390	3,464,621	0.0362	0.9638	70.21
15.5	87,241,728	3,433,595	0.0394	0.9606	67.66
16.5	81,640,400	3,093,805	0.0379	0.9621	65.00
17.5	76,417,524	3,247,983	0.0425	0.9575	62.54
18.5	71,522,381	3,183,435	0.0445	0.9555	59.88
19.5	67,237,096	3,045,570	0.0453	0.9547	57.21
20.5	61,895,219	2,834,635	0.0458	0.9542	54.62
21.5	57,614,570	2,974,116	0.0516	0.9484	52.12
22.5	53,920,690	2,631,120	0.0488	0.9512	49.43
23.5	49,816,952	2,528,172	0.0507	0.9493	47.02
24.5	45,715,390	2,445,918	0.0535	0.9465	44.63
25.5	42,451,140	2,296,157	0.0541	0.9459	42.24
26.5	39,460,865	2,297,707	0.0582	0.9418	39.96
27.5	36,296,649	2,380,142	0.0656	0.9344	37.63
28.5	33,543,433	2,208,180	0.0658	0.9342	35.16
29.5	30,487,012	2,113,093	0.0693	0.9307	32.85
30.5	27,536,726	2,006,555	0.0729	0.9271	30.57
31.5	24,809,491	1,970,025	0.0794	0.9206	28.35
32.5	21,858,050	2,024,395	0.0926	0.9074	26.09
33.5	19,321,546	1,801,655	0.0932	0.9068	23.68
34.5	17,009,001	1,762,680	0.1036	0.8964	21.47
35.5	14,600,208	1,741,825	0.1193	0.8807	19.24
36.5	12,956,870	1,535,278	0.1185	0.8815	16.95
37.5	11,603,274	1,744,442	0.1503	0.8497	14.94
38.5	10,034,064	1,281,832	0.1277	0.8723	12.69

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1897-2018 EXPERIENCE BAND 1917-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,890,552	1,240,522	0.1395	0.8605	11.07
40.5	7,906,693	1,048,957	0.1327	0.8673	9.53
41.5	6,973,846	968,837	0.1389	0.8611	8.26
42.5	6,223,299	896,061	0.1440	0.8560	7.12
43.5	5,563,330	877,822	0.1578	0.8422	6.09
44.5	5,009,443	857,483	0.1712	0.8288	5.13
45.5	4,322,924	784,681	0.1815	0.8185	4.25
46.5	3,650,086	586,860	0.1608	0.8392	3.48
47.5	3,227,775	646,868	0.2004	0.7996	2.92
48.5	2,697,281	501,449	0.1859	0.8141	2.34
49.5	2,294,673	493,478	0.2151	0.7849	1.90
50.5	1,971,155	446,446	0.2265	0.7735	1.49
51.5	1,582,110	336,158	0.2125	0.7875	1.15
52.5	1,270,336	295,319	0.2325	0.7675	0.91
53.5	987,963	224,441	0.2272	0.7728	0.70
54.5	768,506	197,213	0.2566	0.7434	0.54
55.5	575,299	161,545	0.2808	0.7192	0.40
56.5	496,885	154,016	0.3100	0.6900	0.29
57.5	334,739	109,674	0.3276	0.6724	0.20
58.5	279,964	54,739	0.1955	0.8045	0.13
59.5	232,943	33,311	0.1430	0.8570	0.11
60.5	193,926	60,578	0.3124	0.6876	0.09
61.5	133,822	82,439	0.6160	0.3840	0.06
62.5	51,329	9,305	0.1813	0.8187	0.02
63.5	40,497	2,706	0.0668	0.9332	0.02
64.5	37,539	409	0.0109	0.9891	0.02
65.5	34,878	325	0.0093	0.9907	0.02
66.5	30,109	423	0.0140	0.9860	0.02
67.5	24,167	753	0.0311	0.9689	0.02
68.5	20,593	114	0.0055	0.9945	0.02
69.5	19,727	912	0.0462	0.9538	0.02
70.5	18,617	274	0.0147	0.9853	0.02
71.5	17,845	27	0.0015	0.9985	0.02
72.5	17,446	95	0.0054	0.9946	0.02
73.5	17,296	240	0.0139	0.9861	0.02
74.5	16,777	0	0.0000	1.0000	0.02
75.5	16,520		0.0000	1.0000	0.02
76.5	16,520	7	0.0004	0.9996	0.02
77.5	16,572		0.0000	1.0000	0.02
78.5	16,594		0.0000	1.0000	0.02

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1897-2018 EXPERIENCE BAND 1917-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	16,628		0.0000	1.0000	0.02
80.5	16,742		0.0000	1.0000	0.02
81.5	16,719		0.0000	1.0000	0.02
82.5	16,700	29	0.0017	0.9983	0.02
83.5	16,821	11	0.0006	0.9994	0.02
84.5	16,796		0.0000	1.0000	0.02
85.5	16,796	14,106	0.8398	0.1602	0.02
86.5	2,555	23	0.0088	0.9912	0.00
87.5	40,554	11,339	0.2796	0.7204	0.00
88.5	27,905	13,276	0.4758	0.5242	0.00
89.5	14,629		0.0000	1.0000	0.00
90.5	66,332	4,038	0.0609	0.9391	0.00
91.5	62,294	9,416	0.1512	0.8488	0.00
92.5	52,877	2,832	0.0536	0.9464	0.00
93.5	50,045	12,707	0.2539	0.7461	0.00
94.5	37,338	15,605	0.4180	0.5820	0.00
95.5	21,732	11,706	0.5386	0.4614	0.00
96.5	3,795	3,795	1.0000		0.00
97.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1899-2018 EXPERIENCE BAND 1959-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	275,290,136	1,838,961	0.0067	0.9933	100.00
0.5	256,345,112	3,565,746	0.0139	0.9861	99.33
1.5	243,121,143	3,859,972	0.0159	0.9841	97.95
2.5	220,038,015	4,427,537	0.0201	0.9799	96.40
3.5	184,921,828	3,648,498	0.0197	0.9803	94.46
4.5	169,015,689	3,133,129	0.0185	0.9815	92.59
5.5	157,725,949	3,016,647	0.0191	0.9809	90.88
6.5	154,043,401	3,173,387	0.0206	0.9794	89.14
7.5	147,114,896	3,393,286	0.0231	0.9769	87.30
8.5	136,750,558	3,729,410	0.0273	0.9727	85.29
9.5	130,186,051	3,756,342	0.0289	0.9711	82.96
10.5	121,643,459	3,897,428	0.0320	0.9680	80.57
11.5	116,850,357	4,059,841	0.0347	0.9653	77.99
12.5	109,962,523	4,244,648	0.0386	0.9614	75.28
13.5	102,414,122	3,630,712	0.0355	0.9645	72.37
14.5	94,695,001	3,461,890	0.0366	0.9634	69.81
15.5	86,236,846	3,430,246	0.0398	0.9602	67.25
16.5	80,547,685	3,089,059	0.0384	0.9616	64.58
17.5	75,433,293	3,240,411	0.0430	0.9570	62.10
18.5	70,535,368	3,176,601	0.0450	0.9550	59.43
19.5	66,282,799	3,039,196	0.0459	0.9541	56.76
20.5	60,967,061	2,823,414	0.0463	0.9537	54.15
21.5	56,682,783	2,962,497	0.0523	0.9477	51.65
22.5	52,940,756	2,611,779	0.0493	0.9507	48.95
23.5	48,793,400	2,504,080	0.0513	0.9487	46.53
24.5	44,630,557	2,408,899	0.0540	0.9460	44.14
25.5	41,325,950	2,259,735	0.0547	0.9453	41.76
26.5	38,289,860	2,253,201	0.0588	0.9412	39.48
27.5	35,168,066	2,329,667	0.0662	0.9338	37.16
28.5	32,548,645	2,158,947	0.0663	0.9337	34.69
29.5	29,599,291	2,060,946	0.0696	0.9304	32.39
30.5	26,765,875	1,950,417	0.0729	0.9271	30.14
31.5	24,166,962	1,916,680	0.0793	0.9207	27.94
32.5	21,320,662	1,977,688	0.0928	0.9072	25.73
33.5	18,902,539	1,762,996	0.0933	0.9067	23.34
34.5	16,691,293	1,732,197	0.1038	0.8962	21.16
35.5	14,348,660	1,715,333	0.1195	0.8805	18.97
36.5	12,772,176	1,515,609	0.1187	0.8813	16.70
37.5	11,461,004	1,730,604	0.1510	0.8490	14.72
38.5	9,931,424	1,271,004	0.1280	0.8720	12.49

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1899-2018 EXPERIENCE BAND 1959-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,810,233	1,231,796	0.1398	0.8602	10.90
40.5	7,838,499	1,041,942	0.1329	0.8671	9.37
41.5	6,920,772	962,493	0.1391	0.8609	8.13
42.5	6,185,888	890,568	0.1440	0.8560	7.00
43.5	5,538,303	874,131	0.1578	0.8422	5.99
44.5	4,992,027	854,873	0.1712	0.8288	5.04
45.5	4,308,282	782,992	0.1817	0.8183	4.18
46.5	3,636,060	584,178	0.1607	0.8393	3.42
47.5	3,217,723	644,077	0.2002	0.7998	2.87
48.5	2,690,195	500,007	0.1859	0.8141	2.30
49.5	2,289,688	491,031	0.2145	0.7855	1.87
50.5	1,948,441	444,817	0.2283	0.7717	1.47
51.5	1,561,090	335,817	0.2151	0.7849	1.13
52.5	1,249,655	295,016	0.2361	0.7639	0.89
53.5	967,660	224,369	0.2319	0.7681	0.68
54.5	748,358	196,918	0.2631	0.7369	0.52
55.5	555,446	161,312	0.2904	0.7096	0.38
56.5	477,266	153,620	0.3219	0.6781	0.27
57.5	315,515	108,838	0.3450	0.6550	0.19
58.5	279,948	54,723	0.1955	0.8045	0.12
59.5	232,943	33,311	0.1430	0.8570	0.10
60.5	193,926	60,578	0.3124	0.6876	0.08
61.5	133,822	82,439	0.6160	0.3840	0.06
62.5	51,329	9,305	0.1813	0.8187	0.02
63.5	40,497	2,706	0.0668	0.9332	0.02
64.5	37,539	409	0.0109	0.9891	0.02
65.5	34,878	325	0.0093	0.9907	0.02
66.5	30,109	423	0.0140	0.9860	0.02
67.5	24,167	753	0.0311	0.9689	0.02
68.5	20,593	114	0.0055	0.9945	0.02
69.5	19,727	912	0.0462	0.9538	0.02
70.5	18,617	274	0.0147	0.9853	0.01
71.5	17,845	27	0.0015	0.9985	0.01
72.5	17,446	95	0.0054	0.9946	0.01
73.5	17,296	240	0.0139	0.9861	0.01
74.5	16,777	0	0.0000	1.0000	0.01
75.5	16,520		0.0000	1.0000	0.01
76.5	16,520	7	0.0004	0.9996	0.01
77.5	16,572		0.0000	1.0000	0.01
78.5	16,594		0.0000	1.0000	0.01

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1899-2018 EXPERIENCE BAND 1959-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	16,628		0.0000	1.0000	0.01
80.5	16,742		0.0000	1.0000	0.01
81.5	16,719		0.0000	1.0000	0.01
82.5	16,700	29	0.0017	0.9983	0.01
83.5	16,821	11	0.0006	0.9994	0.01
84.5	16,796		0.0000	1.0000	0.01
85.5	16,796	14,106	0.8398	0.1602	0.01
86.5	2,555	23	0.0088	0.9912	0.00
87.5	40,554	11,339	0.2796	0.7204	0.00
88.5	27,905	13,276	0.4758	0.5242	0.00
89.5	14,629		0.0000	1.0000	0.00
90.5	66,332	4,038	0.0609	0.9391	0.00
91.5	62,294	9,416	0.1512	0.8488	0.00
92.5	52,877	2,832	0.0536	0.9464	0.00
93.5	50,045	12,707	0.2539	0.7461	0.00
94.5	37,338	15,605	0.4180	0.5820	0.00
95.5	21,732	11,706	0.5386	0.4614	0.00
96.5	3,795	3,795	1.0000		0.00
97.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1913-2018 EXPERIENCE BAND 1999-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	168,118,140	385,364	0.0023	0.9977	100.00
0.5	154,715,763	1,698,263	0.0110	0.9890	99.77
1.5	146,651,896	2,187,306	0.0149	0.9851	98.68
2.5	128,058,088	2,271,285	0.0177	0.9823	97.20
3.5	105,438,043	1,880,497	0.0178	0.9822	95.48
4.5	94,165,996	1,887,895	0.0200	0.9800	93.78
5.5	86,267,055	2,017,632	0.0234	0.9766	91.90
6.5	85,144,362	2,366,569	0.0278	0.9722	89.75
7.5	81,474,971	2,420,586	0.0297	0.9703	87.25
8.5	74,099,599	2,646,867	0.0357	0.9643	84.66
9.5	68,156,255	2,474,053	0.0363	0.9637	81.64
10.5	63,225,471	2,356,257	0.0373	0.9627	78.67
11.5	63,108,527	2,632,153	0.0417	0.9583	75.74
12.5	61,359,007	2,973,779	0.0485	0.9515	72.58
13.5	57,751,980	2,696,834	0.0467	0.9533	69.06
14.5	54,342,567	2,628,127	0.0484	0.9516	65.84
15.5	50,440,634	2,609,124	0.0517	0.9483	62.66
16.5	47,696,093	2,358,611	0.0495	0.9505	59.41
17.5	43,631,318	2,262,091	0.0518	0.9482	56.48
18.5	40,597,999	2,357,960	0.0581	0.9419	53.55
19.5	37,993,918	2,228,865	0.0587	0.9413	50.44
20.5	34,334,966	2,098,032	0.0611	0.9389	47.48
21.5	31,615,457	2,179,327	0.0689	0.9311	44.58
22.5	29,346,485	1,900,585	0.0648	0.9352	41.51
23.5	26,535,660	1,833,101	0.0691	0.9309	38.82
24.5	23,918,235	1,729,229	0.0723	0.9277	36.14
25.5	22,470,589	1,595,462	0.0710	0.9290	33.52
26.5	20,802,283	1,628,783	0.0783	0.9217	31.14
27.5	18,723,691	1,585,111	0.0847	0.9153	28.70
28.5	17,279,053	1,505,706	0.0871	0.9129	26.27
29.5	15,624,897	1,455,801	0.0932	0.9068	23.98
30.5	14,099,495	1,340,990	0.0951	0.9049	21.75
31.5	12,776,262	1,414,588	0.1107	0.8893	19.68
32.5	11,149,384	1,508,924	0.1353	0.8647	17.50
33.5	9,917,340	1,340,627	0.1352	0.8648	15.13
34.5	8,839,535	1,299,363	0.1470	0.8530	13.09
35.5	7,545,305	1,311,735	0.1738	0.8262	11.16
36.5	6,800,946	1,151,646	0.1693	0.8307	9.22
37.5	6,388,968	1,265,966	0.1981	0.8019	7.66
38.5	5,677,753	1,007,206	0.1774	0.8226	6.14

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-2018 EXPERIENCE BAND 1999-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,291,079	1,020,328	0.1928	0.8072	5.05
40.5	4,776,429	864,834	0.1811	0.8189	4.08
41.5	4,469,581	817,391	0.1829	0.8171	3.34
42.5	4,184,344	772,960	0.1847	0.8153	2.73
43.5	3,984,955	784,125	0.1968	0.8032	2.23
44.5	3,662,642	758,005	0.2070	0.7930	1.79
45.5	3,285,204	707,778	0.2154	0.7846	1.42
46.5	2,792,934	524,453	0.1878	0.8122	1.11
47.5	2,574,151	596,586	0.2318	0.7682	0.90
48.5	2,193,339	472,136	0.2153	0.7847	0.69
49.5	1,906,924	466,887	0.2448	0.7552	0.54
50.5	1,573,583	371,434	0.2360	0.7640	0.41
51.5	1,305,350	321,944	0.2466	0.7534	0.31
52.5	1,044,943	275,148	0.2633	0.7367	0.24
53.5	796,189	213,562	0.2682	0.7318	0.17
54.5	595,194	180,890	0.3039	0.6961	0.13
55.5	425,394	152,370	0.3582	0.6418	0.09
56.5	370,573	132,581	0.3578	0.6422	0.06
57.5	265,781	107,233	0.4035	0.5965	0.04
58.5	167,789	51,701	0.3081	0.6919	0.02
59.5	118,075	21,686	0.1837	0.8163	0.02
60.5	147,845	59,707	0.4038	0.5962	0.01
61.5	88,141	74,751	0.8481	0.1519	0.01
62.5	13,393	8,590	0.6414	0.3586	0.00
63.5	4,805	2,618	0.5448	0.4552	0.00
64.5	2,190	335	0.1529	0.8471	0.00
65.5	1,857	14	0.0076	0.9924	0.00
66.5	1,844	306	0.1658	0.8342	0.00
67.5	1,538	698	0.4536	0.5464	0.00
68.5	841	0	0.0005	0.9995	0.00
69.5	841	841	1.0000		0.00
70.5	0	0	1.0000		
71.5	0	0	1.0000		
72.5	0	0	1.0000		
73.5	0	0	1.0000		
74.5	0	0	1.0000		
75.5					
76.5					
77.5					
78.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

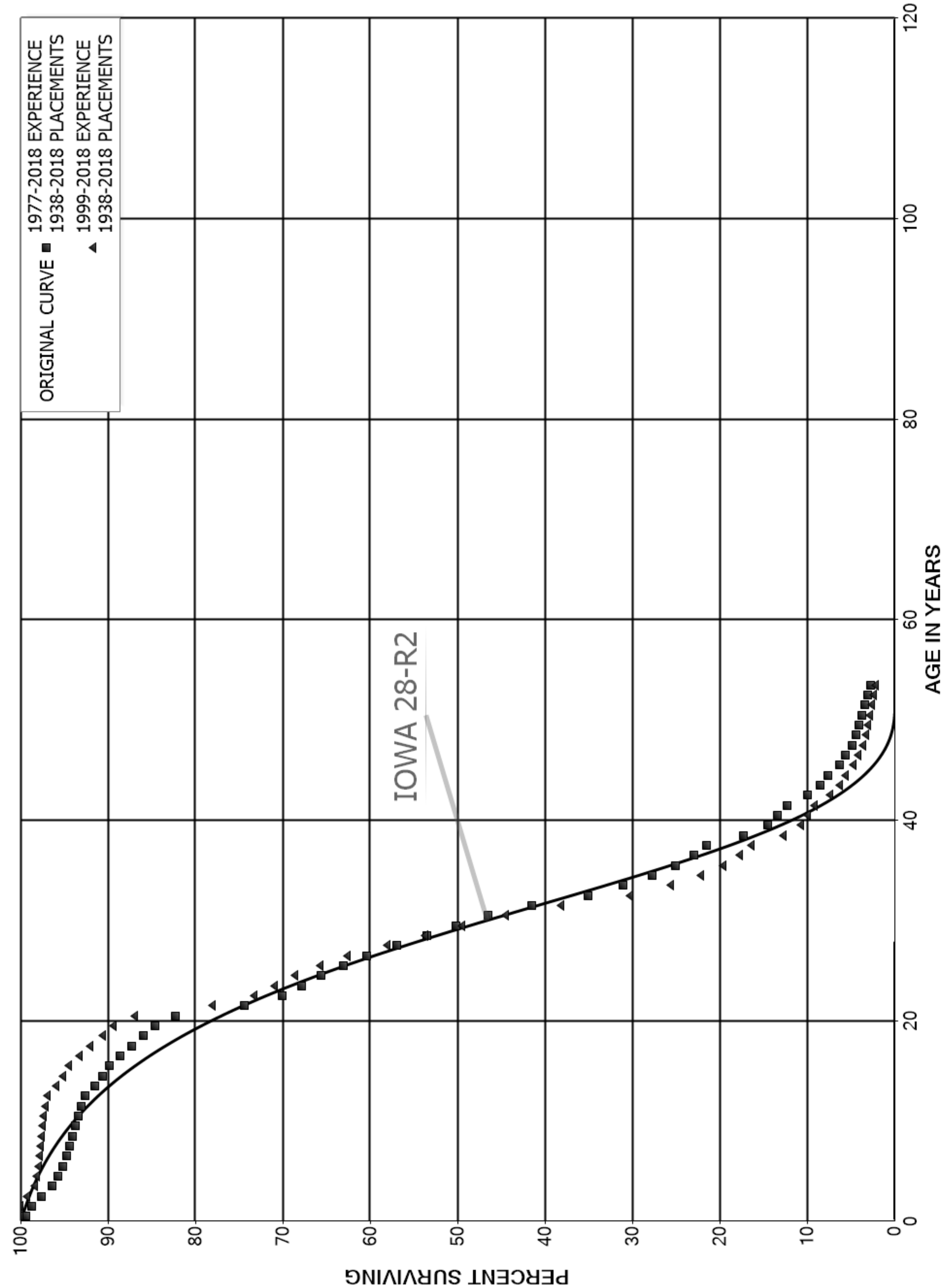
ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-2018 EXPERIENCE BAND 1999-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5					
80.5					
81.5					
82.5					
83.5					
84.5					
85.5					
86.5					
87.5	0	0	1.0000		
88.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1938-2018 EXPERIENCE BAND 1977-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	49,529,572	311,083	0.0063	0.9937	100.00
0.5	48,709,386	331,627	0.0068	0.9932	99.37
1.5	32,084,347	367,467	0.0115	0.9885	98.70
2.5	29,390,506	353,068	0.0120	0.9880	97.57
3.5	26,213,509	169,236	0.0065	0.9935	96.39
4.5	26,481,851	159,274	0.0060	0.9940	95.77
5.5	26,533,556	125,729	0.0047	0.9953	95.19
6.5	25,756,205	90,373	0.0035	0.9965	94.74
7.5	25,133,156	83,025	0.0033	0.9967	94.41
8.5	24,267,042	85,222	0.0035	0.9965	94.10
9.5	23,150,610	86,175	0.0037	0.9963	93.77
10.5	22,037,260	86,576	0.0039	0.9961	93.42
11.5	21,573,593	113,870	0.0053	0.9947	93.05
12.5	20,583,853	241,592	0.0117	0.9883	92.56
13.5	19,376,917	178,621	0.0092	0.9908	91.48
14.5	18,276,084	161,053	0.0088	0.9912	90.63
15.5	17,776,509	251,534	0.0141	0.9859	89.83
16.5	17,398,696	245,730	0.0141	0.9859	88.56
17.5	16,903,288	273,924	0.0162	0.9838	87.31
18.5	16,545,432	243,870	0.0147	0.9853	85.90
19.5	16,154,074	444,217	0.0275	0.9725	84.63
20.5	8,119,859	785,328	0.0967	0.9033	82.30
21.5	7,067,405	409,862	0.0580	0.9420	74.34
22.5	6,559,161	202,386	0.0309	0.9691	70.03
23.5	4,823,336	158,596	0.0329	0.9671	67.87
24.5	3,231,482	126,637	0.0392	0.9608	65.64
25.5	2,149,214	90,336	0.0420	0.9580	63.07
26.5	1,540,802	89,910	0.0584	0.9416	60.42
27.5	1,380,701	81,346	0.0589	0.9411	56.89
28.5	1,159,812	73,128	0.0631	0.9369	53.54
29.5	974,850	71,407	0.0732	0.9268	50.16
30.5	893,875	95,990	0.1074	0.8926	46.49
31.5	760,879	117,178	0.1540	0.8460	41.50
32.5	613,411	70,285	0.1146	0.8854	35.11
33.5	530,372	56,733	0.1070	0.8930	31.08
34.5	445,870	43,555	0.0977	0.9023	27.76
35.5	390,591	32,790	0.0839	0.9161	25.05
36.5	357,802	23,259	0.0650	0.9350	22.94
37.5	334,542	65,180	0.1948	0.8052	21.45
38.5	269,429	42,610	0.1582	0.8418	17.27

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1938-2018 EXPERIENCE BAND 1977-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	226,819	17,797	0.0785	0.9215	14.54
40.5	209,021	16,875	0.0807	0.9193	13.40
41.5	192,147	36,462	0.1898	0.8102	12.32
42.5	155,752	23,686	0.1521	0.8479	9.98
43.5	132,066	13,880	0.1051	0.8949	8.46
44.5	118,186	20,591	0.1742	0.8258	7.57
45.5	97,594	10,678	0.1094	0.8906	6.25
46.5	86,916	11,859	0.1364	0.8636	5.57
47.5	75,057	6,710	0.0894	0.9106	4.81
48.5	68,348	5,764	0.0843	0.9157	4.38
49.5	62,583	4,902	0.0783	0.9217	4.01
50.5	57,681	5,125	0.0889	0.9111	3.70
51.5	52,556	4,321	0.0822	0.9178	3.37
52.5	48,234	5,115	0.1060	0.8940	3.09
53.5	1,015	765	0.7540	0.2460	2.76
54.5	250	37	0.1486	0.8514	0.68
55.5	213	20	0.0924	0.9076	0.58
56.5	193	15	0.0802	0.9198	0.53
57.5	177	20	0.1134	0.8866	0.48
58.5	157		0.0000	1.0000	0.43
59.5	157	5	0.0317	0.9683	0.43
60.5	152	139	0.9092	0.0908	0.41
61.5	14		0.0000	1.0000	0.04
62.5	14	5	0.3591	0.6409	0.04
63.5	9	9	1.0000		0.02
64.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1938-2018 EXPERIENCE BAND 1999-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,845,796	31	0.0000	1.0000	100.00
0.5	36,069,825	17,129	0.0005	0.9995	100.00
1.5	20,877,666	167,127	0.0080	0.9920	99.95
2.5	20,270,210	181,292	0.0089	0.9911	99.15
3.5	19,267,216	41,904	0.0022	0.9978	98.27
4.5	21,457,507	47,959	0.0022	0.9978	98.05
5.5	22,840,300	26,134	0.0011	0.9989	97.83
6.5	23,195,451	28,046	0.0012	0.9988	97.72
7.5	22,884,844	21,915	0.0010	0.9990	97.60
8.5	22,323,863	24,002	0.0011	0.9989	97.51
9.5	21,446,949	31,497	0.0015	0.9985	97.40
10.5	20,387,169	34,075	0.0017	0.9983	97.26
11.5	19,994,610	64,251	0.0032	0.9968	97.10
12.5	19,064,167	196,575	0.0103	0.9897	96.79
13.5	17,912,166	135,784	0.0076	0.9924	95.79
14.5	16,933,769	118,726	0.0070	0.9930	95.06
15.5	16,547,746	212,904	0.0129	0.9871	94.40
16.5	16,237,351	212,832	0.0131	0.9869	93.18
17.5	15,828,491	243,393	0.0154	0.9846	91.96
18.5	15,536,836	210,317	0.0135	0.9865	90.55
19.5	15,223,228	416,261	0.0273	0.9727	89.32
20.5	7,261,236	749,223	0.1032	0.8968	86.88
21.5	6,274,683	385,434	0.0614	0.9386	77.91
22.5	5,825,821	182,679	0.0314	0.9686	73.13
23.5	4,147,405	139,202	0.0336	0.9664	70.83
24.5	2,632,015	107,734	0.0409	0.9591	68.46
25.5	1,624,940	77,773	0.0479	0.9521	65.66
26.5	1,076,292	78,422	0.0729	0.9271	62.51
27.5	963,152	72,216	0.0750	0.9250	57.96
28.5	784,589	61,775	0.0787	0.9213	53.61
29.5	650,737	65,624	0.1008	0.8992	49.39
30.5	623,307	88,627	0.1422	0.8578	44.41
31.5	546,327	112,912	0.2067	0.7933	38.10
32.5	441,203	68,092	0.1543	0.8457	30.22
33.5	410,947	55,929	0.1361	0.8639	25.56
34.5	370,382	43,297	0.1169	0.8831	22.08
35.5	345,771	32,790	0.0948	0.9052	19.50
36.5	312,982	23,259	0.0743	0.9257	17.65
37.5	289,862	65,180	0.2249	0.7751	16.34
38.5	269,323	42,610	0.1582	0.8418	12.66

JERSEY CENTRAL POWER & LIGHT COMPANY

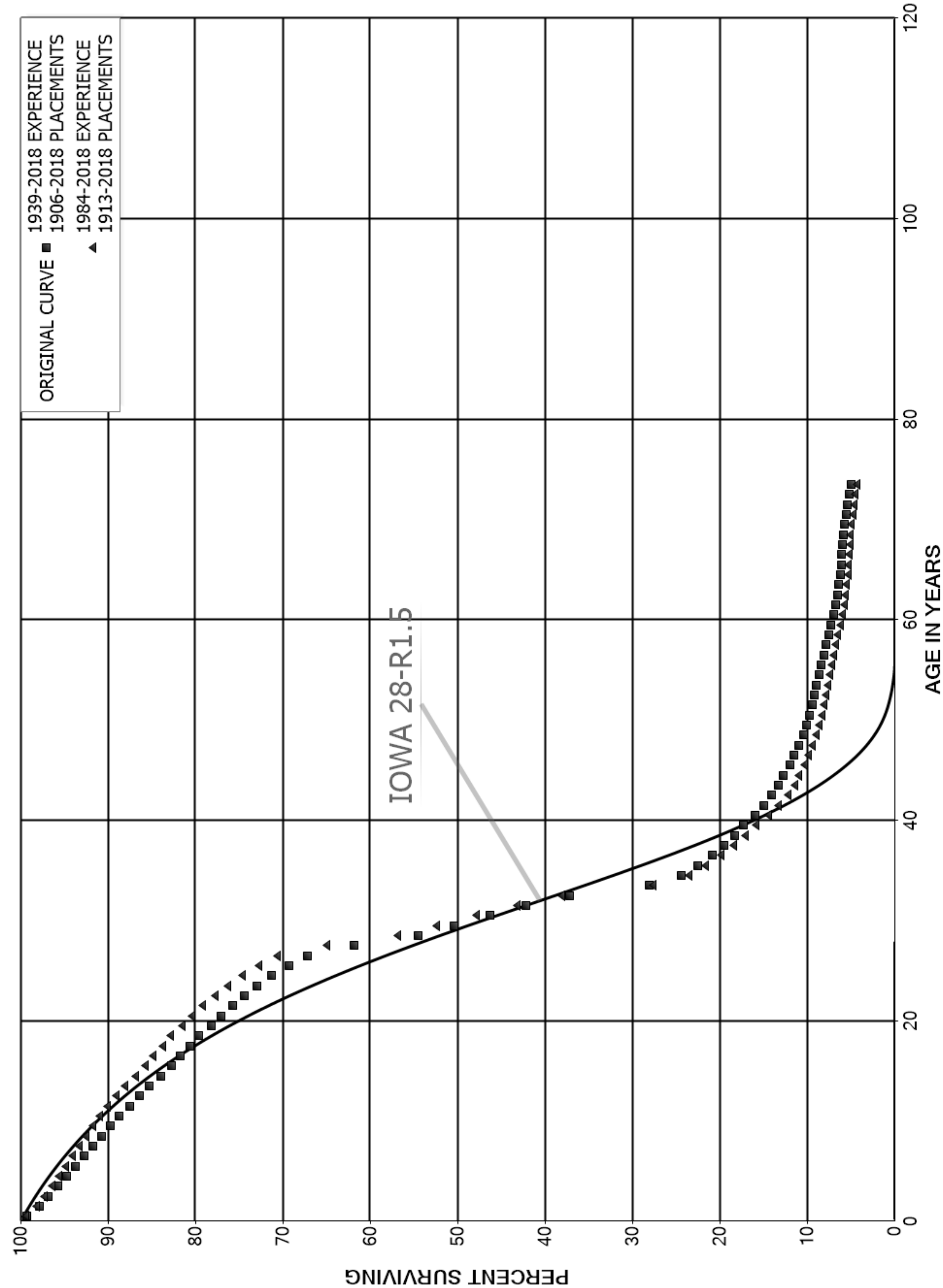
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1938-2018 EXPERIENCE BAND 1999-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	226,712	17,797	0.0785	0.9215	10.66
40.5	208,915	16,875	0.0808	0.9192	9.82
41.5	192,040	36,462	0.1899	0.8101	9.03
42.5	155,579	23,686	0.1522	0.8478	7.32
43.5	131,893	13,880	0.1052	0.8948	6.20
44.5	118,052	20,591	0.1744	0.8256	5.55
45.5	97,461	10,678	0.1096	0.8904	4.58
46.5	86,783	11,859	0.1367	0.8633	4.08
47.5	74,924	6,710	0.0896	0.9104	3.52
48.5	68,214	5,764	0.0845	0.9155	3.21
49.5	62,450	4,902	0.0785	0.9215	2.94
50.5	57,547	5,125	0.0891	0.9109	2.71
51.5	52,422	4,321	0.0824	0.9176	2.46
52.5	48,101	5,115	0.1063	0.8937	2.26
53.5	881	765	0.8682	0.1318	2.02
54.5	116	37	0.3195	0.6805	0.27
55.5	79	20	0.2484	0.7516	0.18
56.5	59	15	0.2606	0.7394	0.14
57.5	44	20	0.4581	0.5419	0.10
58.5	24		0.0000	1.0000	0.05
59.5	24	5	0.2092	0.7908	0.05
60.5	152	139	0.9092	0.0908	0.04
61.5	14		0.0000	1.0000	0.00
62.5	14	5	0.3591	0.6409	0.00
63.5	9	9	1.0000		0.00
64.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1939-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	309,122,534	2,305,298	0.0075	0.9925	100.00
0.5	295,218,192	4,148,909	0.0141	0.9859	99.25
1.5	275,276,268	3,017,026	0.0110	0.9890	97.86
2.5	258,944,219	2,738,369	0.0106	0.9894	96.79
3.5	232,496,083	2,403,672	0.0103	0.9897	95.76
4.5	227,353,064	2,402,410	0.0106	0.9894	94.77
5.5	220,776,350	2,340,325	0.0106	0.9894	93.77
6.5	201,974,296	2,223,572	0.0110	0.9890	92.78
7.5	191,209,368	2,160,577	0.0113	0.9887	91.76
8.5	179,225,310	2,017,191	0.0113	0.9887	90.72
9.5	168,296,531	1,929,593	0.0115	0.9885	89.70
10.5	157,438,054	1,988,496	0.0126	0.9874	88.67
11.5	148,385,646	1,882,685	0.0127	0.9873	87.55
12.5	137,611,693	1,904,285	0.0138	0.9862	86.44
13.5	125,751,171	1,965,457	0.0156	0.9844	85.24
14.5	116,806,373	1,611,252	0.0138	0.9862	83.91
15.5	110,476,668	1,418,124	0.0128	0.9872	82.75
16.5	104,601,535	1,414,350	0.0135	0.9865	81.69
17.5	90,455,100	1,147,307	0.0127	0.9873	80.59
18.5	84,023,351	1,418,582	0.0169	0.9831	79.56
19.5	76,009,398	1,159,272	0.0153	0.9847	78.22
20.5	65,248,914	1,084,776	0.0166	0.9834	77.03
21.5	60,285,197	1,093,751	0.0181	0.9819	75.75
22.5	56,244,759	1,099,886	0.0196	0.9804	74.37
23.5	52,780,828	1,216,556	0.0230	0.9770	72.92
24.5	49,355,781	1,371,138	0.0278	0.9722	71.24
25.5	44,956,254	1,331,112	0.0296	0.9704	69.26
26.5	41,701,497	3,313,456	0.0795	0.9205	67.21
27.5	36,602,137	4,352,887	0.1189	0.8811	61.87
28.5	30,845,922	2,299,625	0.0746	0.9254	54.51
29.5	26,719,566	2,186,896	0.0818	0.9182	50.45
30.5	22,110,566	1,998,497	0.0904	0.9096	46.32
31.5	17,719,818	2,074,318	0.1171	0.8829	42.13
32.5	14,090,634	3,473,402	0.2465	0.7535	37.20
33.5	10,335,396	1,340,314	0.1297	0.8703	28.03
34.5	8,394,461	640,843	0.0763	0.9237	24.39
35.5	7,278,134	546,260	0.0751	0.9249	22.53
36.5	6,389,538	411,402	0.0644	0.9356	20.84
37.5	5,900,852	359,652	0.0609	0.9391	19.50
38.5	5,518,597	323,800	0.0587	0.9413	18.31

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1939-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,293,159	405,651	0.0766	0.9234	17.24
40.5	4,991,174	296,248	0.0594	0.9406	15.92
41.5	4,733,414	295,112	0.0623	0.9377	14.97
42.5	4,573,855	229,092	0.0501	0.9499	14.04
43.5	4,269,330	194,973	0.0457	0.9543	13.33
44.5	4,102,115	241,364	0.0588	0.9412	12.73
45.5	3,739,267	162,178	0.0434	0.9566	11.98
46.5	3,451,103	162,652	0.0471	0.9529	11.46
47.5	3,206,633	143,316	0.0447	0.9553	10.92
48.5	2,973,231	100,619	0.0338	0.9662	10.43
49.5	2,859,853	114,789	0.0401	0.9599	10.08
50.5	2,740,112	78,680	0.0287	0.9713	9.67
51.5	2,607,244	70,578	0.0271	0.9729	9.39
52.5	2,502,612	65,666	0.0262	0.9738	9.14
53.5	2,400,639	73,699	0.0307	0.9693	8.90
54.5	2,270,289	64,355	0.0283	0.9717	8.63
55.5	2,141,831	71,520	0.0334	0.9666	8.38
56.5	2,254,936	68,313	0.0303	0.9697	8.10
57.5	2,164,252	85,901	0.0397	0.9603	7.86
58.5	2,033,122	84,461	0.0415	0.9585	7.55
59.5	1,876,111	73,917	0.0394	0.9606	7.23
60.5	1,759,927	59,148	0.0336	0.9664	6.95
61.5	1,630,456	54,468	0.0334	0.9666	6.71
62.5	1,529,275	32,315	0.0211	0.9789	6.49
63.5	1,471,843	38,990	0.0265	0.9735	6.35
64.5	1,414,669	16,494	0.0117	0.9883	6.18
65.5	1,379,391	10,389	0.0075	0.9925	6.11
66.5	1,362,544	28,754	0.0211	0.9789	6.07
67.5	1,320,299	26,520	0.0201	0.9799	5.94
68.5	1,284,955	9,948	0.0077	0.9923	5.82
69.5	1,266,952	50,099	0.0395	0.9605	5.77
70.5	1,214,469	38,709	0.0319	0.9681	5.54
71.5	1,174,770	44,462	0.0378	0.9622	5.37
72.5	1,128,617	40,117	0.0355	0.9645	5.16
73.5	145,366	24,146	0.1661	0.8339	4.98
74.5	120,336	18,742	0.1557	0.8443	4.15
75.5	10,259	53	0.0052	0.9948	3.51
76.5	8,874		0.0000	1.0000	3.49
77.5	8,874		0.0000	1.0000	3.49
78.5	8,874		0.0000	1.0000	3.49

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1939-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	8,874		0.0000	1.0000	3.49
80.5	8,874		0.0000	1.0000	3.49
81.5	8,874	12	0.0013	0.9987	3.49
82.5	8,863	3	0.0003	0.9997	3.48
83.5	8,860		0.0000	1.0000	3.48
84.5	6,410	278	0.0433	0.9567	3.48
85.5	6,132	6,132	1.0000		3.33
86.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1913-2018 EXPERIENCE BAND 1984-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	265,375,401	1,885,631	0.0071	0.9929	100.00
0.5	254,286,270	3,184,381	0.0125	0.9875	99.29
1.5	237,349,416	2,188,738	0.0092	0.9908	98.05
2.5	223,998,715	1,918,369	0.0086	0.9914	97.14
3.5	200,763,752	1,623,032	0.0081	0.9919	96.31
4.5	198,392,318	1,664,893	0.0084	0.9916	95.53
5.5	193,952,166	1,613,767	0.0083	0.9917	94.73
6.5	177,004,894	1,447,959	0.0082	0.9918	93.94
7.5	168,449,286	1,451,421	0.0086	0.9914	93.17
8.5	158,548,961	1,339,784	0.0085	0.9915	92.37
9.5	149,965,710	1,287,983	0.0086	0.9914	91.59
10.5	141,182,814	1,410,223	0.0100	0.9900	90.80
11.5	133,994,250	1,384,893	0.0103	0.9897	89.90
12.5	124,547,692	1,467,683	0.0118	0.9882	88.97
13.5	113,779,990	1,577,987	0.0139	0.9861	87.92
14.5	105,934,995	1,261,244	0.0119	0.9881	86.70
15.5	100,749,136	1,150,187	0.0114	0.9886	85.67
16.5	95,727,463	1,187,128	0.0124	0.9876	84.69
17.5	82,338,172	920,354	0.0112	0.9888	83.64
18.5	76,732,600	1,198,102	0.0156	0.9844	82.70
19.5	69,539,650	972,416	0.0140	0.9860	81.41
20.5	59,566,656	915,454	0.0154	0.9846	80.27
21.5	55,182,507	966,276	0.0175	0.9825	79.04
22.5	51,504,460	997,400	0.0194	0.9806	77.66
23.5	48,378,117	1,047,356	0.0216	0.9784	76.15
24.5	45,435,160	1,158,474	0.0255	0.9745	74.50
25.5	41,486,304	1,173,479	0.0283	0.9717	72.60
26.5	38,707,808	3,150,814	0.0814	0.9186	70.55
27.5	33,973,091	4,242,830	0.1249	0.8751	64.81
28.5	28,412,107	2,246,266	0.0791	0.9209	56.71
29.5	24,401,201	2,120,760	0.0869	0.9131	52.23
30.5	19,879,229	1,907,082	0.0959	0.9041	47.69
31.5	15,590,650	1,870,981	0.1200	0.8800	43.12
32.5	12,197,323	3,363,342	0.2757	0.7243	37.94
33.5	8,567,411	1,260,147	0.1471	0.8529	27.48
34.5	6,729,525	560,576	0.0833	0.9167	23.44
35.5	5,694,783	462,484	0.0812	0.9188	21.49
36.5	4,890,876	349,303	0.0714	0.9286	19.74
37.5	4,470,010	330,565	0.0740	0.9260	18.33
38.5	4,115,758	299,063	0.0727	0.9273	16.97

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-2018 EXPERIENCE BAND 1984-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,915,375	370,928	0.0947	0.9053	15.74
40.5	3,649,858	267,474	0.0733	0.9267	14.25
41.5	3,425,762	286,732	0.0837	0.9163	13.21
42.5	3,300,315	215,150	0.0652	0.9348	12.10
43.5	4,022,868	181,721	0.0452	0.9548	11.31
44.5	3,890,856	238,652	0.0613	0.9387	10.80
45.5	3,547,913	157,100	0.0443	0.9557	10.14
46.5	3,289,248	154,914	0.0471	0.9529	9.69
47.5	3,063,085	135,273	0.0442	0.9558	9.23
48.5	2,860,421	98,375	0.0344	0.9656	8.83
49.5	2,749,874	113,019	0.0411	0.9589	8.52
50.5	2,632,627	77,863	0.0296	0.9704	8.17
51.5	2,520,514	69,493	0.0276	0.9724	7.93
52.5	2,439,774	64,426	0.0264	0.9736	7.71
53.5	2,347,222	72,890	0.0311	0.9689	7.51
54.5	2,252,972	64,276	0.0285	0.9715	7.27
55.5	2,126,800	71,520	0.0336	0.9664	7.07
56.5	2,240,319	68,313	0.0305	0.9695	6.83
57.5	2,149,760	85,500	0.0398	0.9602	6.62
58.5	2,021,690	84,124	0.0416	0.9584	6.36
59.5	1,865,015	73,917	0.0396	0.9604	6.09
60.5	1,748,884	59,148	0.0338	0.9662	5.85
61.5	1,619,413	54,455	0.0336	0.9664	5.65
62.5	1,519,575	32,315	0.0213	0.9787	5.46
63.5	1,462,143	38,910	0.0266	0.9734	5.35
64.5	1,405,791	16,491	0.0117	0.9883	5.21
65.5	1,370,516	10,389	0.0076	0.9924	5.14
66.5	1,353,682	28,754	0.0212	0.9788	5.11
67.5	1,311,436	26,520	0.0202	0.9798	5.00
68.5	1,276,092	9,948	0.0078	0.9922	4.90
69.5	1,258,370	50,099	0.0398	0.9602	4.86
70.5	1,214,469	38,709	0.0319	0.9681	4.66
71.5	1,174,770	44,462	0.0378	0.9622	4.52
72.5	1,128,617	40,117	0.0355	0.9645	4.34
73.5	145,366	24,146	0.1661	0.8339	4.19
74.5	120,336	18,742	0.1557	0.8443	3.49
75.5	10,259	53	0.0052	0.9948	2.95
76.5	8,874		0.0000	1.0000	2.93
77.5	8,874		0.0000	1.0000	2.93
78.5	8,874		0.0000	1.0000	2.93

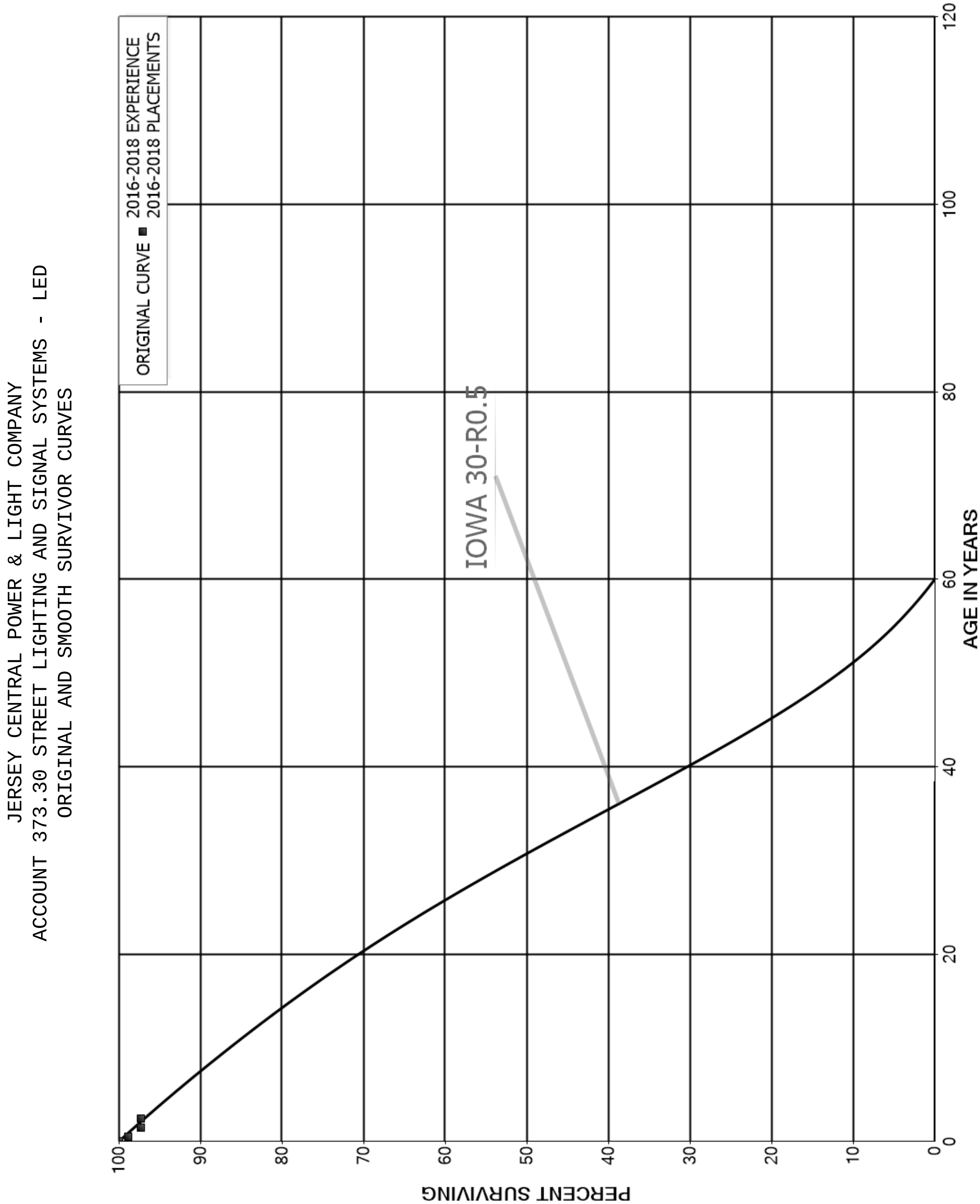
JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-2018 EXPERIENCE BAND 1984-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	8,874		0.0000	1.0000	2.93
80.5	8,874		0.0000	1.0000	2.93
81.5	8,874	12	0.0013	0.9987	2.93
82.5	8,863	3	0.0003	0.9997	2.93
83.5	8,860		0.0000	1.0000	2.93
84.5	6,410	278	0.0433	0.9567	2.93
85.5	6,132	6,132	1.0000		2.80
86.5					


JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 373.30 STREET LIGHTING AND SIGNAL SYSTEMS - LED
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 2016-2018 EXPERIENCE
2016-2018 PLACEMENTS
IOWA 30-R0.5
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
20
40
60
80
100
120

JERSEY CENTRAL POWER & LIGHT COMPANY

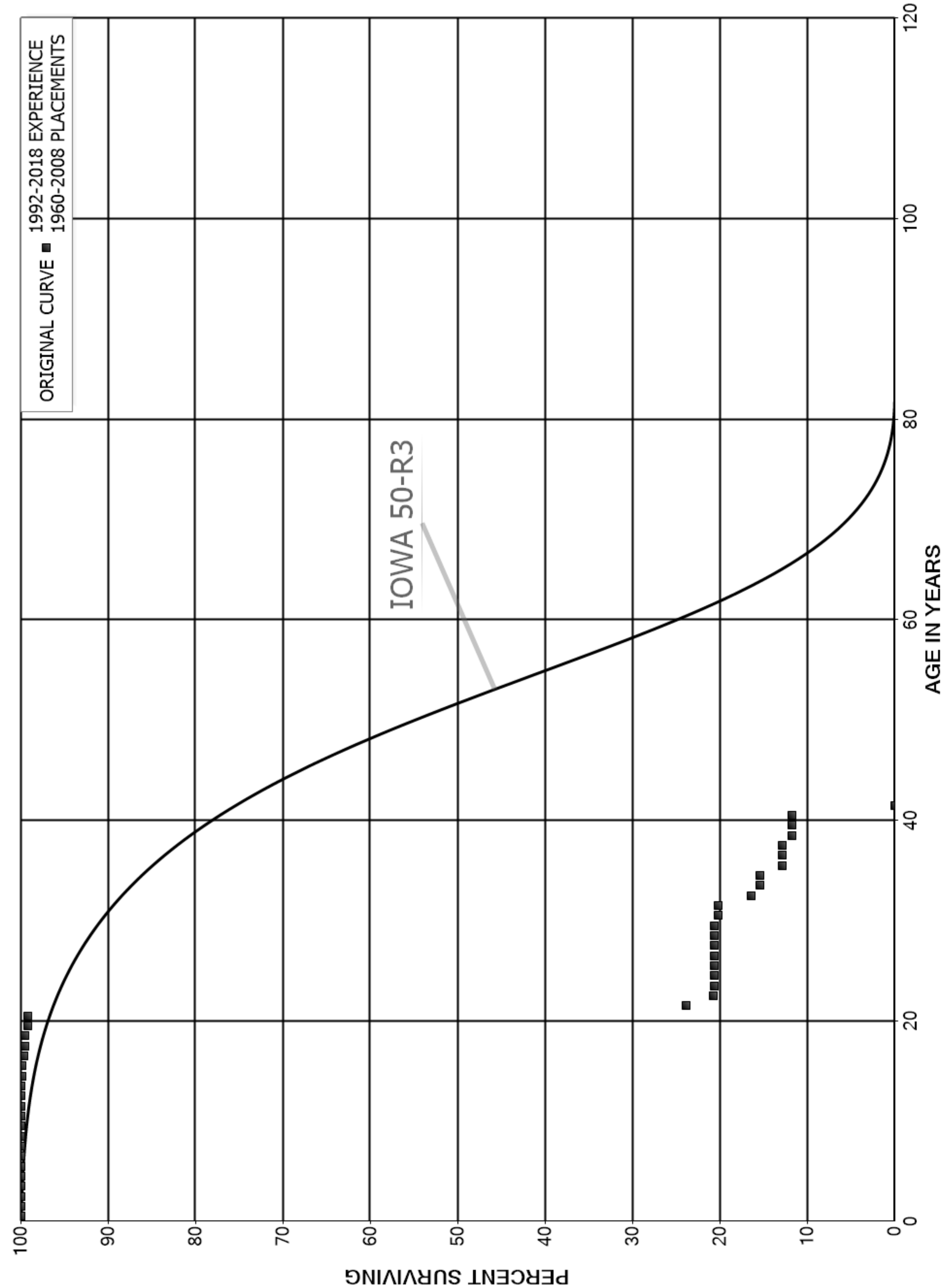
ACCOUNT 373.30 STREET LIGHTING AND SIGNAL SYSTEMS - LED

ORIGINAL LIFE TABLE

PLACEMENT BAND 2016-2018 EXPERIENCE BAND 2016-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	289,369	3,432	0.0119	0.9881	100.00
0.5	58,926	888	0.0151	0.9849	98.81
1.5	2,002		0.0000	1.0000	97.33
2.5					97.33

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 389.20 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 389.20 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2008 EXPERIENCE BAND 1992-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	87,034		0.0000	1.0000	100.00
0.5	87,034		0.0000	1.0000	100.00
1.5	87,034		0.0000	1.0000	100.00
2.5	87,034		0.0000	1.0000	100.00
3.5	87,034		0.0000	1.0000	100.00
4.5	87,034	81	0.0009	0.9991	100.00
5.5	86,953	14	0.0002	0.9998	99.91
6.5	86,939		0.0000	1.0000	99.89
7.5	86,939		0.0000	1.0000	99.89
8.5	88,799		0.0000	1.0000	99.89
9.5	88,799		0.0000	1.0000	99.89
10.5	93,565		0.0000	1.0000	99.89
11.5	93,565		0.0000	1.0000	99.89
12.5	93,565		0.0000	1.0000	99.89
13.5	97,095	18	0.0002	0.9998	99.89
14.5	97,077	1	0.0000	1.0000	99.87
15.5	103,602	257	0.0025	0.9975	99.87
16.5	116,886	102	0.0009	0.9991	99.62
17.5	116,783	4	0.0000	1.0000	99.54
18.5	116,779	441	0.0038	0.9962	99.53
19.5	116,338	15	0.0001	0.9999	99.16
20.5	116,324	88,356	0.7596	0.2404	99.14
21.5	27,968	3,676	0.1314	0.8686	23.84
22.5	24,292	81	0.0033	0.9967	20.70
23.5	24,211		0.0000	1.0000	20.64
24.5	24,211		0.0000	1.0000	20.64
25.5	24,211		0.0000	1.0000	20.64
26.5	24,211		0.0000	1.0000	20.64
27.5	24,211		0.0000	1.0000	20.64
28.5	24,211		0.0000	1.0000	20.64
29.5	24,211	526	0.0217	0.9783	20.64
30.5	23,685		0.0000	1.0000	20.19
31.5	23,685	4,497	0.1899	0.8101	20.19
32.5	19,697	1,221	0.0620	0.9380	16.35
33.5	18,476		0.0000	1.0000	15.34
34.5	18,481	3,075	0.1664	0.8336	15.34
35.5	15,406		0.0000	1.0000	12.79
36.5	15,406	0	0.0000	1.0000	12.79
37.5	15,406	1,253	0.0813	0.9187	12.79
38.5	14,153		0.0000	1.0000	11.75

JERSEY CENTRAL POWER & LIGHT COMPANY

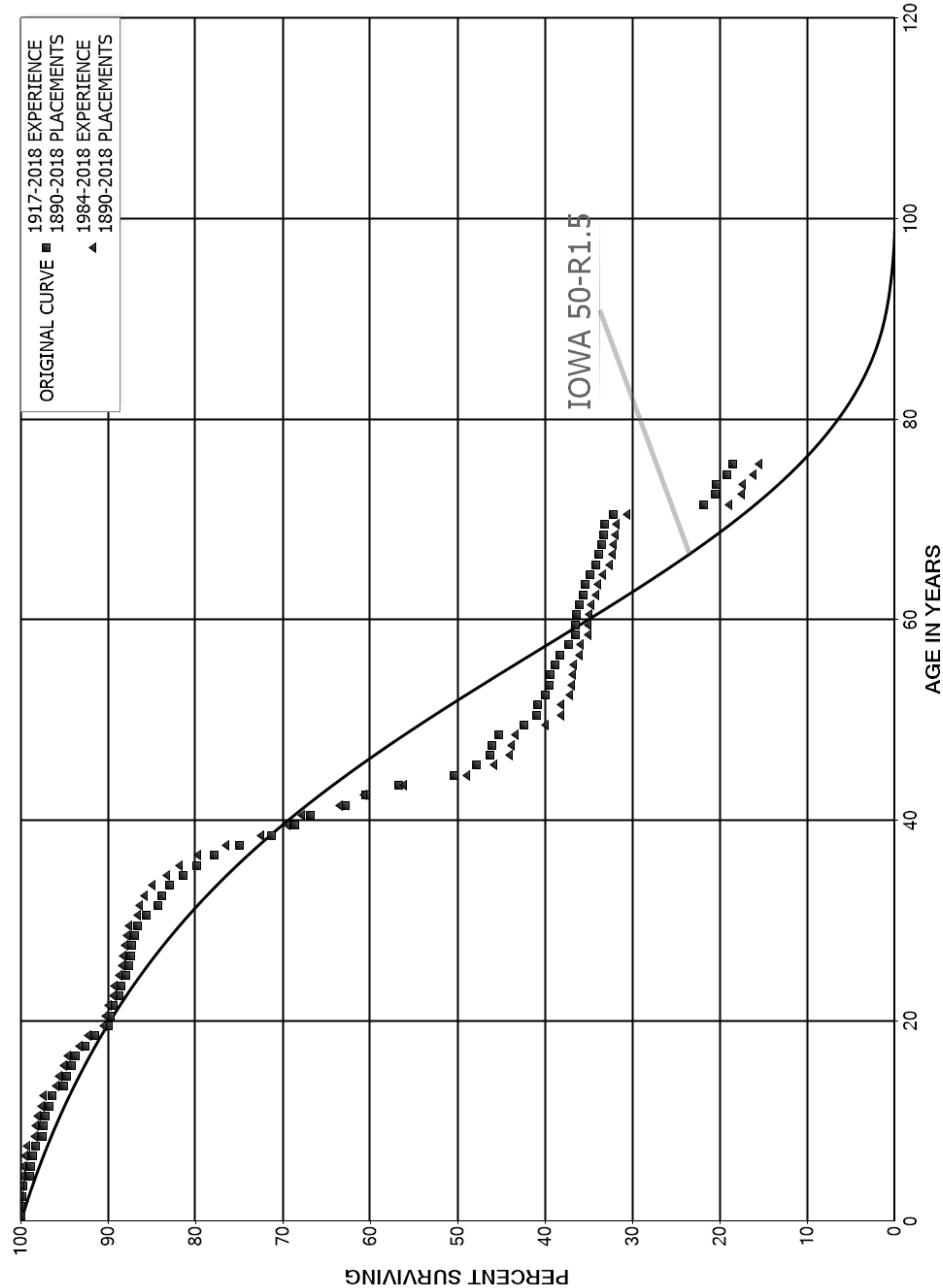
ACCOUNT 389.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2008 EXPERIENCE BAND 1992-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,080	5	0.0006	0.9994	11.75
40.5	94	94	1.0000		11.74
41.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1917-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	167,874,565	65,133	0.0004	0.9996	100.00
0.5	158,624,424	83,207	0.0005	0.9995	99.96
1.5	141,619,929	41,237	0.0003	0.9997	99.91
2.5	137,324,824	168,778	0.0012	0.9988	99.88
3.5	132,026,932	1,068,168	0.0081	0.9919	99.76
4.5	129,245,101	189,796	0.0015	0.9985	98.95
5.5	127,598,302	293,885	0.0023	0.9977	98.80
6.5	126,103,042	325,584	0.0026	0.9974	98.58
7.5	122,289,608	961,701	0.0079	0.9921	98.32
8.5	119,881,172	208,404	0.0017	0.9983	97.55
9.5	115,024,285	285,464	0.0025	0.9975	97.38
10.5	112,105,379	515,441	0.0046	0.9954	97.14
11.5	110,583,824	322,730	0.0029	0.9971	96.69
12.5	108,095,037	1,469,669	0.0136	0.9864	96.41
13.5	101,566,531	422,505	0.0042	0.9958	95.10
14.5	100,325,557	557,071	0.0056	0.9944	94.70
15.5	96,151,173	433,305	0.0045	0.9955	94.18
16.5	94,551,113	1,197,088	0.0127	0.9873	93.75
17.5	89,769,851	982,379	0.0109	0.9891	92.57
18.5	85,462,226	1,502,582	0.0176	0.9824	91.55
19.5	82,362,470	191,877	0.0023	0.9977	89.94
20.5	74,199,415	294,252	0.0040	0.9960	89.73
21.5	71,878,602	514,999	0.0072	0.9928	89.38
22.5	69,859,926	144,879	0.0021	0.9979	88.74
23.5	67,388,843	440,175	0.0065	0.9935	88.55
24.5	65,725,583	260,527	0.0040	0.9960	87.97
25.5	62,716,564	151,030	0.0024	0.9976	87.63
26.5	57,354,310	105,811	0.0018	0.9982	87.41
27.5	53,183,887	168,510	0.0032	0.9968	87.25
28.5	41,228,579	190,900	0.0046	0.9954	86.98
29.5	39,544,615	421,487	0.0107	0.9893	86.57
30.5	36,453,798	568,844	0.0156	0.9844	85.65
31.5	30,548,754	168,964	0.0055	0.9945	84.32
32.5	27,632,855	286,817	0.0104	0.9896	83.85
33.5	21,463,956	405,063	0.0189	0.9811	82.98
34.5	19,517,440	369,389	0.0189	0.9811	81.41
35.5	18,730,235	488,479	0.0261	0.9739	79.87
36.5	17,341,409	629,535	0.0363	0.9637	77.79
37.5	15,168,872	740,976	0.0488	0.9512	74.96
38.5	14,117,709	539,481	0.0382	0.9618	71.30

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1917-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,074,936	308,346	0.0255	0.9745	68.58
40.5	11,840,931	701,041	0.0592	0.9408	66.83
41.5	11,244,469	421,841	0.0375	0.9625	62.87
42.5	10,861,957	686,428	0.0632	0.9368	60.51
43.5	10,066,908	1,108,246	0.1101	0.8899	56.69
44.5	8,800,281	450,717	0.0512	0.9488	50.45
45.5	8,164,838	277,049	0.0339	0.9661	47.86
46.5	7,843,254	36,876	0.0047	0.9953	46.24
47.5	7,704,320	130,586	0.0169	0.9831	46.02
48.5	7,026,233	440,135	0.0626	0.9374	45.24
49.5	6,307,260	223,735	0.0355	0.9645	42.41
50.5	6,113,336	17,752	0.0029	0.9971	40.90
51.5	5,520,052	105,627	0.0191	0.9809	40.78
52.5	4,622,035	55,017	0.0119	0.9881	40.00
53.5	4,343,045	9,285	0.0021	0.9979	39.53
54.5	3,856,273	57,986	0.0150	0.9850	39.44
55.5	3,735,371	52,280	0.0140	0.9860	38.85
56.5	3,453,065	90,268	0.0261	0.9739	38.31
57.5	3,301,140	67,850	0.0206	0.9794	37.31
58.5	2,905,146	6,527	0.0022	0.9978	36.54
59.5	2,400,234	6,006	0.0025	0.9975	36.46
60.5	2,022,325	15,778	0.0078	0.9922	36.37
61.5	1,806,420	21,796	0.0121	0.9879	36.08
62.5	1,451,641	8,171	0.0056	0.9944	35.65
63.5	1,427,465	22,766	0.0159	0.9841	35.45
64.5	1,381,535	27,885	0.0202	0.9798	34.88
65.5	1,329,210	14,972	0.0113	0.9887	34.18
66.5	1,294,264	12,774	0.0099	0.9901	33.79
67.5	1,258,949	6,930	0.0055	0.9945	33.46
68.5	1,257,415	2,941	0.0023	0.9977	33.27
69.5	1,298,459	41,548	0.0320	0.9680	33.20
70.5	1,228,923	395,776	0.3221	0.6779	32.13
71.5	826,241	49,252	0.0596	0.9404	21.78
72.5	778,655	2,834	0.0036	0.9964	20.49
73.5	803,992	50,108	0.0623	0.9377	20.41
74.5	743,921	26,029	0.0350	0.9650	19.14
75.5	672,731	2,664	0.0040	0.9960	18.47
76.5	667,546	1,773	0.0027	0.9973	18.40
77.5	664,723	2,739	0.0041	0.9959	18.35
78.5	654,016	251	0.0004	0.9996	18.27

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1917-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	630,016	11,805	0.0187	0.9813	18.27
80.5	604,704	828	0.0014	0.9986	17.92
81.5	602,859		0.0000	1.0000	17.90
82.5	602,859	0	0.0000	1.0000	17.90
83.5	601,210	45	0.0001	0.9999	17.90
84.5	601,165	3,532	0.0059	0.9941	17.90
85.5	593,391	6,565	0.0111	0.9889	17.79
86.5	585,368	1,847	0.0032	0.9968	17.60
87.5	574,544	16,749	0.0292	0.9708	17.54
88.5	396,798	46	0.0001	0.9999	17.03
89.5	387,915	0	0.0000	1.0000	17.03
90.5	248,311	87	0.0003	0.9997	17.03
91.5	241,351	6,521	0.0270	0.9730	17.02
92.5	200,246	9,902	0.0494	0.9506	16.56
93.5	123,184		0.0000	1.0000	15.74
94.5	121,202		0.0000	1.0000	15.74
95.5	120,230		0.0000	1.0000	15.74
96.5	115,802	260	0.0022	0.9978	15.74
97.5	115,542	28	0.0002	0.9998	15.71
98.5	115,515	2,594	0.0225	0.9775	15.70
99.5	112,921		0.0000	1.0000	15.35
100.5	112,921		0.0000	1.0000	15.35
101.5	112,921		0.0000	1.0000	15.35
102.5	112,921		0.0000	1.0000	15.35
103.5	112,921		0.0000	1.0000	15.35
104.5	112,921		0.0000	1.0000	15.35
105.5	112,921		0.0000	1.0000	15.35
106.5	112,921		0.0000	1.0000	15.35
107.5	66,467		0.0000	1.0000	15.35
108.5	62,263		0.0000	1.0000	15.35
109.5	62,263		0.0000	1.0000	15.35
110.5	62,263		0.0000	1.0000	15.35
111.5	62,263		0.0000	1.0000	15.35
112.5	62,263		0.0000	1.0000	15.35
113.5	62,263		0.0000	1.0000	15.35
114.5	62,263		0.0000	1.0000	15.35
115.5	62,263		0.0000	1.0000	15.35
116.5	37,267		0.0000	1.0000	15.35
117.5	37,267		0.0000	1.0000	15.35
118.5	37,267		0.0000	1.0000	15.35

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1917-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	37,267		0.0000	1.0000	15.35
120.5	37,267		0.0000	1.0000	15.35
121.5	37,267		0.0000	1.0000	15.35
122.5	14,807		0.0000	1.0000	15.35
123.5	14,807		0.0000	1.0000	15.35
124.5	14,807		0.0000	1.0000	15.35
125.5	14,807		0.0000	1.0000	15.35
126.5	14,807		0.0000	1.0000	15.35
127.5	14,807		0.0000	1.0000	15.35
128.5					15.35

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1984-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	137,386,527	12,183	0.0001	0.9999	100.00
0.5	132,357,828	79,108	0.0006	0.9994	99.99
1.5	115,211,397	19,820	0.0002	0.9998	99.93
2.5	111,589,798	38,588	0.0003	0.9997	99.91
3.5	106,904,852	120,392	0.0011	0.9989	99.88
4.5	107,242,597	145,928	0.0014	0.9986	99.77
5.5	107,476,461	249,151	0.0023	0.9977	99.63
6.5	106,390,608	267,449	0.0025	0.9975	99.40
7.5	102,765,838	871,200	0.0085	0.9915	99.15
8.5	100,439,504	118,174	0.0012	0.9988	98.31
9.5	96,257,187	232,653	0.0024	0.9976	98.19
10.5	93,855,134	425,395	0.0045	0.9955	97.96
11.5	92,951,188	237,289	0.0026	0.9974	97.51
12.5	90,872,519	1,313,293	0.0145	0.9855	97.26
13.5	85,586,857	339,341	0.0040	0.9960	95.86
14.5	84,988,095	495,864	0.0058	0.9942	95.48
15.5	82,183,837	392,427	0.0048	0.9952	94.92
16.5	81,923,753	1,122,279	0.0137	0.9863	94.47
17.5	79,299,376	889,638	0.0112	0.9888	93.17
18.5	75,932,780	1,422,078	0.0187	0.9813	92.13
19.5	73,683,113	159,093	0.0022	0.9978	90.40
20.5	65,864,017	262,131	0.0040	0.9960	90.21
21.5	64,801,874	376,597	0.0058	0.9942	89.85
22.5	63,488,041	95,015	0.0015	0.9985	89.33
23.5	61,885,648	421,801	0.0068	0.9932	89.19
24.5	61,712,031	226,617	0.0037	0.9963	88.59
25.5	59,238,377	82,531	0.0014	0.9986	88.26
26.5	54,187,361	94,049	0.0017	0.9983	88.14
27.5	50,618,186	151,575	0.0030	0.9970	87.98
28.5	38,214,006	105,914	0.0028	0.9972	87.72
29.5	36,888,150	391,887	0.0106	0.9894	87.48
30.5	34,139,208	113,259	0.0033	0.9967	86.55
31.5	28,687,276	161,076	0.0056	0.9944	86.26
32.5	25,915,084	274,764	0.0106	0.9894	85.78
33.5	19,757,099	390,019	0.0197	0.9803	84.87
34.5	17,810,458	314,806	0.0177	0.9823	83.19
35.5	16,906,977	446,463	0.0264	0.9736	81.72
36.5	15,602,452	615,876	0.0395	0.9605	79.56
37.5	13,453,974	709,968	0.0528	0.9472	76.42
38.5	12,427,491	523,455	0.0421	0.9579	72.39

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1984-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,331,977	248,128	0.0240	0.9760	69.34
40.5	10,159,434	649,184	0.0639	0.9361	67.68
41.5	9,586,650	415,706	0.0434	0.9566	63.35
42.5	9,204,804	682,066	0.0741	0.9259	60.60
43.5	8,421,930	1,098,397	0.1304	0.8696	56.11
44.5	7,072,311	449,865	0.0636	0.9364	48.79
45.5	6,498,402	242,195	0.0373	0.9627	45.69
46.5	6,182,335	34,075	0.0055	0.9945	43.99
47.5	6,048,157	58,995	0.0098	0.9902	43.75
48.5	5,449,781	439,317	0.0806	0.9194	43.32
49.5	4,732,108	206,237	0.0436	0.9564	39.83
50.5	4,538,507	4,827	0.0011	0.9989	38.09
51.5	3,965,684	105,334	0.0266	0.9734	38.05
52.5	3,097,944	21,643	0.0070	0.9930	37.04
53.5	3,008,931	6,279	0.0021	0.9979	36.78
54.5	2,566,602	3,515	0.0014	0.9986	36.70
55.5	2,754,335	52,280	0.0190	0.9810	36.65
56.5	2,939,909	11,009	0.0037	0.9963	35.96
57.5	2,888,805	67,850	0.0235	0.9765	35.82
58.5	2,596,684	6,160	0.0024	0.9976	34.98
59.5	2,099,428	2,064	0.0010	0.9990	34.90
60.5	1,727,170	13,457	0.0078	0.9922	34.87
61.5	1,519,524	21,796	0.0143	0.9857	34.59
62.5	1,165,306	8,121	0.0070	0.9930	34.10
63.5	1,152,659	17,836	0.0155	0.9845	33.86
64.5	1,089,282	27,877	0.0256	0.9744	33.34
65.5	1,038,561	9,609	0.0093	0.9907	32.48
66.5	1,010,674	2,902	0.0029	0.9971	32.18
67.5	985,249	6,930	0.0070	0.9930	32.09
68.5	989,395	2,941	0.0030	0.9970	31.86
69.5	1,037,042	41,548	0.0401	0.9599	31.77
70.5	998,138	382,042	0.3828	0.6172	30.50
71.5	625,673	49,252	0.0787	0.9213	18.82
72.5	661,752	2,834	0.0043	0.9957	17.34
73.5	690,676	50,108	0.0725	0.9275	17.27
74.5	630,634	26,029	0.0413	0.9587	16.01
75.5	565,931	1,464	0.0026	0.9974	15.35
76.5	571,940	1,773	0.0031	0.9969	15.31
77.5	569,117	2,739	0.0048	0.9952	15.27
78.5	558,410	251	0.0004	0.9996	15.19

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1984-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	551,973	1,552	0.0028	0.9972	15.19
80.5	536,915	828	0.0015	0.9985	15.14
81.5	560,326		0.0000	1.0000	15.12
82.5	562,947	0	0.0000	1.0000	15.12
83.5	561,298	45	0.0001	0.9999	15.12
84.5	561,252	3,532	0.0063	0.9937	15.12
85.5	556,124	6,565	0.0118	0.9882	15.02
86.5	548,102	1,847	0.0034	0.9966	14.85
87.5	559,737	16,749	0.0299	0.9701	14.80
88.5	381,991	46	0.0001	0.9999	14.35
89.5	373,108	0	0.0000	1.0000	14.35
90.5	233,503	87	0.0004	0.9996	14.35
91.5	226,544	6,521	0.0288	0.9712	14.35
92.5	185,439	9,902	0.0534	0.9466	13.93
93.5	123,184		0.0000	1.0000	13.19
94.5	121,202		0.0000	1.0000	13.19
95.5	120,230		0.0000	1.0000	13.19
96.5	115,802	260	0.0022	0.9978	13.19
97.5	115,542	28	0.0002	0.9998	13.16
98.5	115,515	2,594	0.0225	0.9775	13.16
99.5	112,921		0.0000	1.0000	12.86
100.5	112,921		0.0000	1.0000	12.86
101.5	112,921		0.0000	1.0000	12.86
102.5	112,921		0.0000	1.0000	12.86
103.5	112,921		0.0000	1.0000	12.86
104.5	112,921		0.0000	1.0000	12.86
105.5	112,921		0.0000	1.0000	12.86
106.5	112,921		0.0000	1.0000	12.86
107.5	66,467		0.0000	1.0000	12.86
108.5	62,263		0.0000	1.0000	12.86
109.5	62,263		0.0000	1.0000	12.86
110.5	62,263		0.0000	1.0000	12.86
111.5	62,263		0.0000	1.0000	12.86
112.5	62,263		0.0000	1.0000	12.86
113.5	62,263		0.0000	1.0000	12.86
114.5	62,263		0.0000	1.0000	12.86
115.5	62,263		0.0000	1.0000	12.86
116.5	37,267		0.0000	1.0000	12.86
117.5	37,267		0.0000	1.0000	12.86
118.5	37,267		0.0000	1.0000	12.86

JERSEY CENTRAL POWER & LIGHT COMPANY

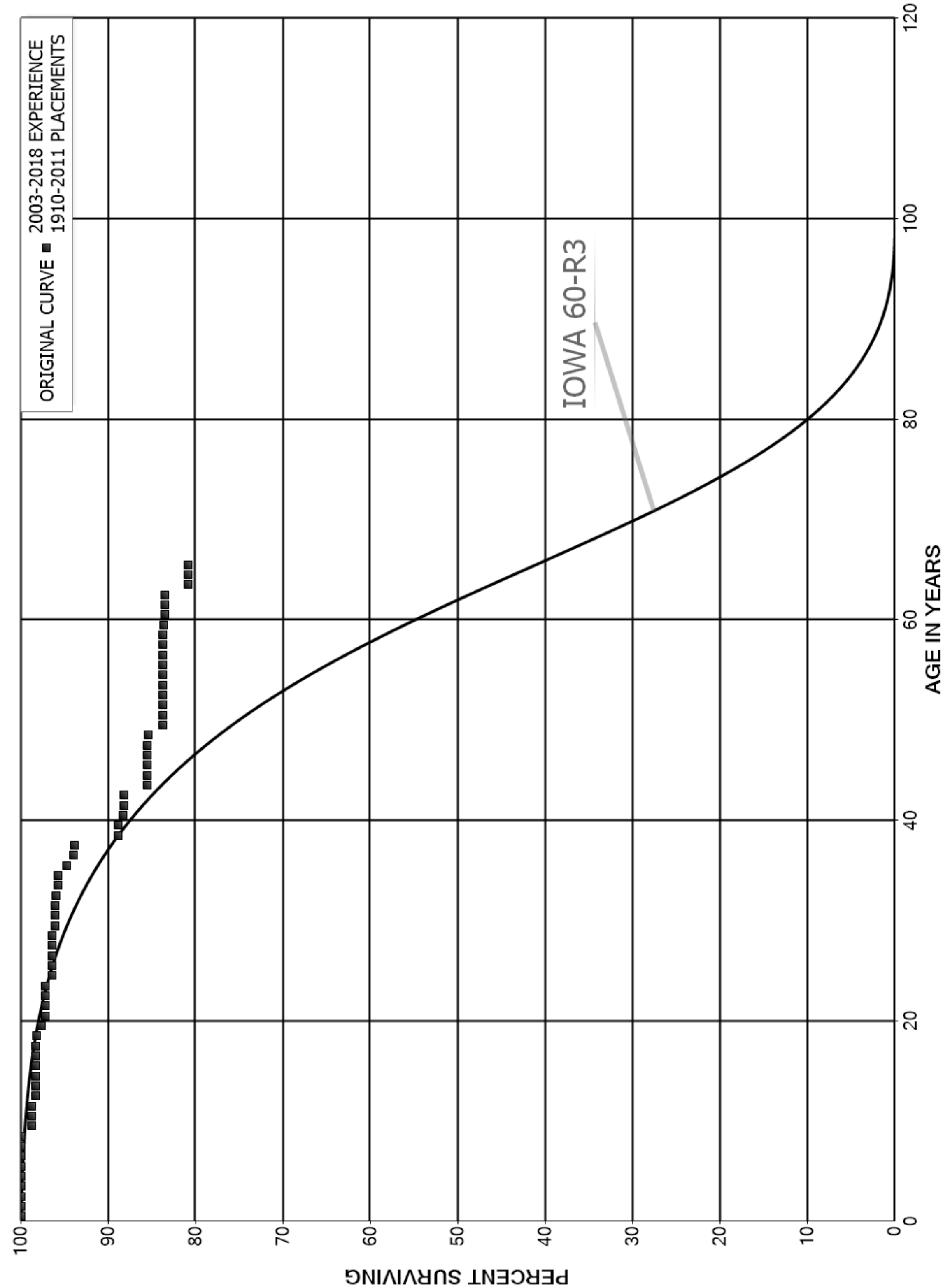
ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1984-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	37,267		0.0000	1.0000	12.86
120.5	37,267		0.0000	1.0000	12.86
121.5	37,267		0.0000	1.0000	12.86
122.5	14,807		0.0000	1.0000	12.86
123.5	14,807		0.0000	1.0000	12.86
124.5	14,807		0.0000	1.0000	12.86
125.5	14,807		0.0000	1.0000	12.86
126.5	14,807		0.0000	1.0000	12.86
127.5	14,807		0.0000	1.0000	12.86
128.5					12.86

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2011 EXPERIENCE BAND 2003-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,016,144		0.0000	1.0000	100.00
0.5	1,090,414		0.0000	1.0000	100.00
1.5	1,237,413		0.0000	1.0000	100.00
2.5	1,280,857		0.0000	1.0000	100.00
3.5	1,622,268		0.0000	1.0000	100.00
4.5	1,796,362		0.0000	1.0000	100.00
5.5	2,270,085		0.0000	1.0000	100.00
6.5	2,796,479		0.0000	1.0000	100.00
7.5	2,826,058		0.0000	1.0000	100.00
8.5	3,146,655	39,530	0.0126	0.9874	100.00
9.5	3,427,385		0.0000	1.0000	98.74
10.5	3,060,794		0.0000	1.0000	98.74
11.5	3,278,010	13,986	0.0043	0.9957	98.74
12.5	4,444,908		0.0000	1.0000	98.32
13.5	5,492,263		0.0000	1.0000	98.32
14.5	6,047,283		0.0000	1.0000	98.32
15.5	6,894,556		0.0000	1.0000	98.32
16.5	7,001,270		0.0000	1.0000	98.32
17.5	7,580,444	14,667	0.0019	0.9981	98.32
18.5	7,469,116	37,638	0.0050	0.9950	98.13
19.5	7,692,055	34,081	0.0044	0.9956	97.64
20.5	8,468,027	3,482	0.0004	0.9996	97.21
21.5	8,323,933	1,246	0.0001	0.9999	97.17
22.5	8,505,946	150	0.0000	1.0000	97.15
23.5	8,192,205	67,902	0.0083	0.9917	97.15
24.5	7,928,638		0.0000	1.0000	96.34
25.5	7,768,272		0.0000	1.0000	96.34
26.5	7,551,195		0.0000	1.0000	96.34
27.5	6,367,240		0.0000	1.0000	96.34
28.5	5,340,773	15,387	0.0029	0.9971	96.34
29.5	4,896,738		0.0000	1.0000	96.07
30.5	4,084,065		0.0000	1.0000	96.07
31.5	3,886,745	3,704	0.0010	0.9990	96.07
32.5	3,295,936	8,945	0.0027	0.9973	95.97
33.5	3,198,624	139	0.0000	1.0000	95.71
34.5	2,913,941	30,772	0.0106	0.9894	95.71
35.5	1,785,585	15,098	0.0085	0.9915	94.70
36.5	1,574,602	1,474	0.0009	0.9991	93.90
37.5	1,657,500	88,382	0.0533	0.9467	93.81
38.5	1,654,633	375	0.0002	0.9998	88.81

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2011 EXPERIENCE BAND 2003-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,618,779	8,806	0.0054	0.9946	88.79
40.5	1,497,215	2,276	0.0015	0.9985	88.31
41.5	1,619,088	806	0.0005	0.9995	88.17
42.5	1,668,198	48,731	0.0292	0.9708	88.13
43.5	1,666,857		0.0000	1.0000	85.55
44.5	1,726,852		0.0000	1.0000	85.55
45.5	1,713,467		0.0000	1.0000	85.55
46.5	1,686,204	1,790	0.0011	0.9989	85.55
47.5	1,726,002	902	0.0005	0.9995	85.46
48.5	1,601,147	30,781	0.0192	0.9808	85.42
49.5	1,528,018		0.0000	1.0000	83.78
50.5	1,479,202		0.0000	1.0000	83.78
51.5	1,332,159	1,353	0.0010	0.9990	83.78
52.5	985,977		0.0000	1.0000	83.69
53.5	868,359		0.0000	1.0000	83.69
54.5	718,164		0.0000	1.0000	83.69
55.5	675,674		0.0000	1.0000	83.69
56.5	497,622		0.0000	1.0000	83.69
57.5	433,996		0.0000	1.0000	83.69
58.5	376,561	500	0.0013	0.9987	83.69
59.5	227,058	150	0.0007	0.9993	83.58
60.5	189,506		0.0000	1.0000	83.52
61.5	167,172		0.0000	1.0000	83.52
62.5	100,305	3,260	0.0325	0.9675	83.52
63.5	77,370		0.0000	1.0000	80.81
64.5	38,387		0.0000	1.0000	80.81
65.5	16,153		0.0000	1.0000	80.81
66.5	15,618		0.0000	1.0000	80.81
67.5	7,853		0.0000	1.0000	80.81
68.5	7,706		0.0000	1.0000	80.81
69.5	7,706		0.0000	1.0000	80.81
70.5	7,625		0.0000	1.0000	80.81
71.5	7,620		0.0000	1.0000	80.81
72.5	7,620		0.0000	1.0000	80.81
73.5	7,743		0.0000	1.0000	80.81
74.5	17,706		0.0000	1.0000	80.81
75.5	62,579		0.0000	1.0000	80.81
76.5	65,099		0.0000	1.0000	80.81
77.5	64,444		0.0000	1.0000	80.81
78.5	69,985		0.0000	1.0000	80.81

JERSEY CENTRAL POWER & LIGHT COMPANY

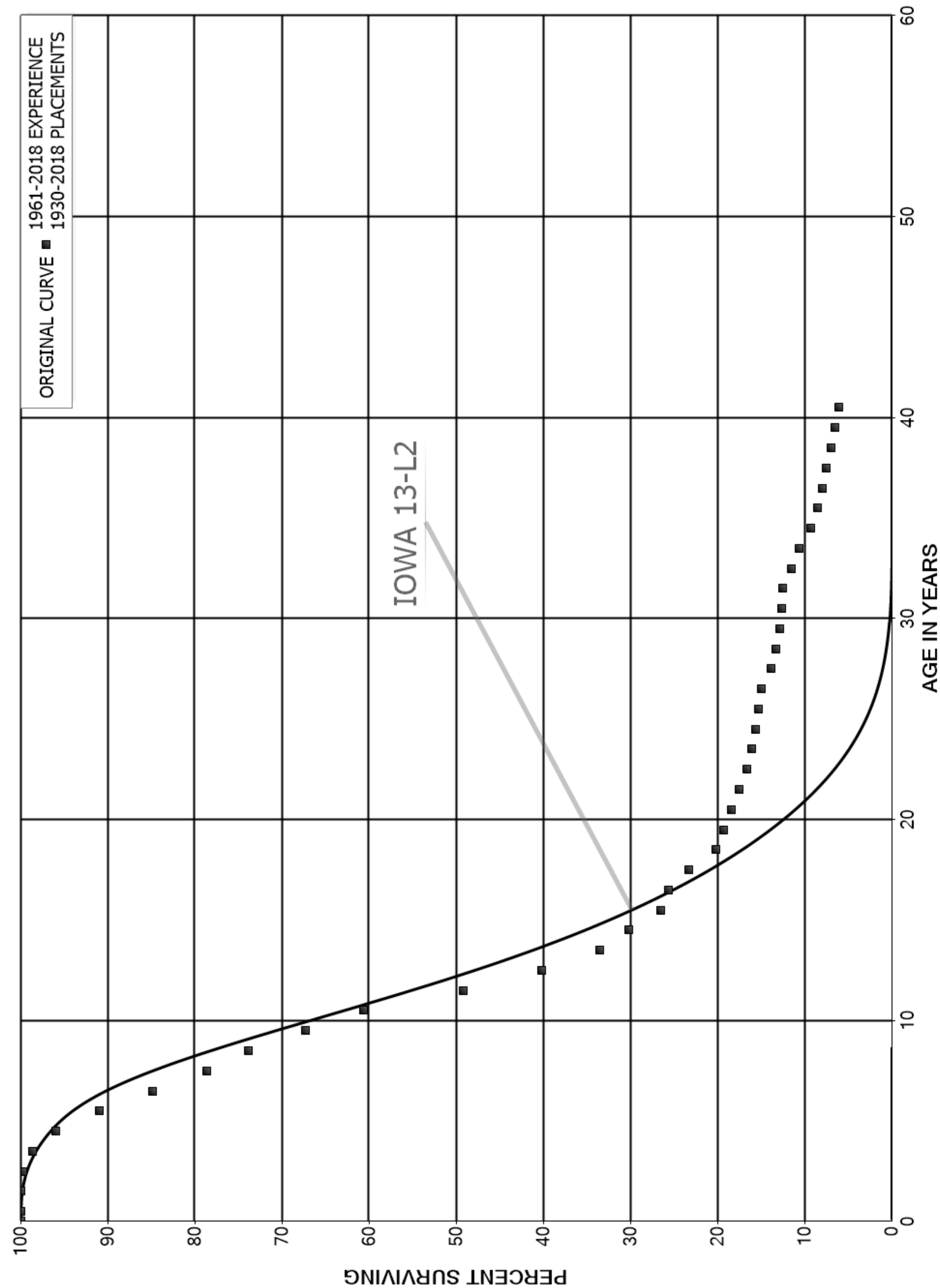
ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2011 EXPERIENCE BAND 2003-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	71,196		0.0000	1.0000	80.81
80.5	70,370	174	0.0025	0.9975	80.81
81.5	70,587		0.0000	1.0000	80.61
82.5	70,587		0.0000	1.0000	80.61
83.5	70,553		0.0000	1.0000	80.61
84.5	71,033		0.0000	1.0000	80.61
85.5	72,629		0.0000	1.0000	80.61
86.5	71,921		0.0000	1.0000	80.61
87.5	71,921		0.0000	1.0000	80.61
88.5	70,801		0.0000	1.0000	80.61
89.5	61,013		0.0000	1.0000	80.61
90.5	15,851		0.0000	1.0000	80.61
91.5	13,331		0.0000	1.0000	80.61
92.5	12,982		0.0000	1.0000	80.61
93.5	8,355		0.0000	1.0000	80.61
94.5	6,839		0.0000	1.0000	80.61
95.5	4,202		0.0000	1.0000	80.61
96.5	3,810		0.0000	1.0000	80.61
97.5	3,810		0.0000	1.0000	80.61
98.5	3,810		0.0000	1.0000	80.61
99.5	3,330		0.0000	1.0000	80.61
100.5	1,734		0.0000	1.0000	80.61
101.5	1,734		0.0000	1.0000	80.61
102.5	1,734		0.0000	1.0000	80.61
103.5	1,734		0.0000	1.0000	80.61
104.5	1,734		0.0000	1.0000	80.61
105.5	1,734		0.0000	1.0000	80.61
106.5	1,734		0.0000	1.0000	80.61
107.5	1,032		0.0000	1.0000	80.61
108.5					80.61

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1930-2018 EXPERIENCE BAND 1961-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	21,976,507		0.0000	1.0000	100.00
0.5	21,209,343	7,795	0.0004	0.9996	100.00
1.5	20,463,911	57,839	0.0028	0.9972	99.96
2.5	19,495,629	202,897	0.0104	0.9896	99.68
3.5	19,697,829	531,972	0.0270	0.9730	98.64
4.5	19,000,593	994,733	0.0524	0.9476	95.98
5.5	17,691,232	1,196,352	0.0676	0.9324	90.95
6.5	16,695,067	1,219,995	0.0731	0.9269	84.80
7.5	15,594,822	948,702	0.0608	0.9392	78.61
8.5	14,596,458	1,295,796	0.0888	0.9112	73.82
9.5	12,804,864	1,276,127	0.0997	0.9003	67.27
10.5	11,553,964	2,165,956	0.1875	0.8125	60.57
11.5	9,427,784	1,725,146	0.1830	0.8170	49.21
12.5	7,594,823	1,269,404	0.1671	0.8329	40.21
13.5	6,337,326	618,852	0.0977	0.9023	33.49
14.5	5,279,747	643,299	0.1218	0.8782	30.22
15.5	4,642,019	164,380	0.0354	0.9646	26.54
16.5	4,409,944	392,177	0.0889	0.9111	25.60
17.5	4,012,390	536,879	0.1338	0.8662	23.32
18.5	3,211,848	147,382	0.0459	0.9541	20.20
19.5	2,773,426	131,610	0.0475	0.9525	19.27
20.5	1,658,577	76,614	0.0462	0.9538	18.36
21.5	1,584,533	76,480	0.0483	0.9517	17.51
22.5	1,476,904	55,083	0.0373	0.9627	16.66
23.5	1,421,939	41,086	0.0289	0.9711	16.04
24.5	1,284,677	25,425	0.0198	0.9802	15.58
25.5	1,204,245	23,295	0.0193	0.9807	15.27
26.5	1,150,564	91,145	0.0792	0.9208	14.98
27.5	844,606	30,216	0.0358	0.9642	13.79
28.5	750,629	23,064	0.0307	0.9693	13.30
29.5	715,007	15,053	0.0211	0.9789	12.89
30.5	433,776	4,955	0.0114	0.9886	12.62
31.5	346,556	27,136	0.0783	0.9217	12.47
32.5	319,420	23,552	0.0737	0.9263	11.50
33.5	222,631	28,815	0.1294	0.8706	10.65
34.5	190,233	15,398	0.0809	0.9191	9.27
35.5	171,763	11,017	0.0641	0.9359	8.52
36.5	160,746	8,930	0.0556	0.9444	7.97
37.5	150,889	11,189	0.0742	0.9258	7.53
38.5	140,372	9,407	0.0670	0.9330	6.97

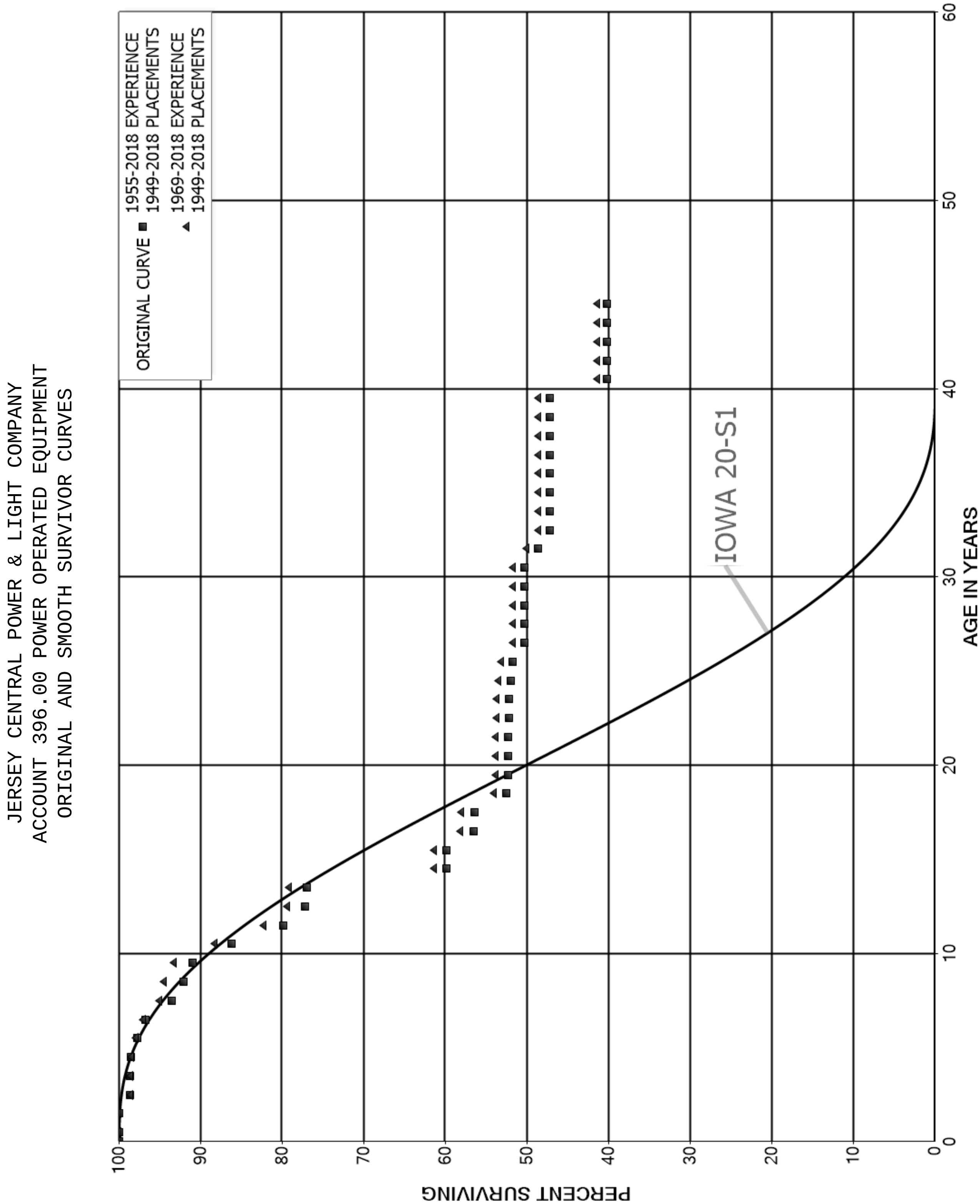
JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1930-2018 EXPERIENCE BAND 1961-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	109,737	6,552	0.0597	0.9403	6.50
40.5	89,129	405	0.0045	0.9955	6.12
41.5	84,143	928	0.0110	0.9890	6.09
42.5	45,872	3,316	0.0723	0.9277	6.02
43.5	42,555	3,564	0.0837	0.9163	5.59
44.5	38,992	1,570	0.0403	0.9597	5.12
45.5	37,422		0.0000	1.0000	4.91
46.5	37,422	333	0.0089	0.9911	4.91
47.5	33,341	108	0.0032	0.9968	4.87
48.5	33,111		0.0000	1.0000	4.85
49.5	5,886	166	0.0283	0.9717	4.85
50.5	5,609	1,044	0.1862	0.8138	4.72
51.5	5,074	1,834	0.3615	0.6385	3.84
52.5	3,240	585	0.1806	0.8194	2.45
53.5	2,655	713	0.2686	0.7314	2.01
54.5	1,942		0.0000	1.0000	1.47
55.5	1,942		0.0000	1.0000	1.47
56.5	1,942		0.0000	1.0000	1.47
57.5	1,942		0.0000	1.0000	1.47
58.5	1,942		0.0000	1.0000	1.47
59.5	1,942	124	0.0637	0.9363	1.47
60.5	1,818	199	0.1094	0.8906	1.37
61.5	1,619		0.0000	1.0000	1.22
62.5	1,619		0.0000	1.0000	1.22
63.5	1,619	1,476	0.9119	0.0881	1.22
64.5	143		0.0000	1.0000	0.11
65.5	143	143	1.0000		0.11
66.5					



JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 396.00 POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE
1955-2018 EXPERIENCE
1949-2018 PLACEMENTS
1969-2018 EXPERIENCE
1949-2018 PLACEMENTS
IOWA 20-S1
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 1955-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,948,641		0.0000	1.0000	100.00
0.5	4,824,037	3,337	0.0007	0.9993	100.00
1.5	4,652,742	61,869	0.0133	0.9867	99.93
2.5	4,551,442	684	0.0002	0.9998	98.60
3.5	4,007,909	5,364	0.0013	0.9987	98.59
4.5	4,080,665	32,269	0.0079	0.9921	98.46
5.5	4,079,517	37,642	0.0092	0.9908	97.68
6.5	4,019,782	135,774	0.0338	0.9662	96.78
7.5	3,898,856	62,094	0.0159	0.9841	93.51
8.5	3,915,919	45,188	0.0115	0.9885	92.02
9.5	3,819,217	199,708	0.0523	0.9477	90.96
10.5	3,612,669	264,626	0.0732	0.9268	86.20
11.5	3,646,396	122,712	0.0337	0.9663	79.89
12.5	3,581,500	11,185	0.0031	0.9969	77.20
13.5	3,572,152	796,019	0.2228	0.7772	76.96
14.5	3,135,077		0.0000	1.0000	59.81
15.5	3,631,694	198,058	0.0545	0.9455	59.81
16.5	3,516,788	11,101	0.0032	0.9968	56.55
17.5	3,426,606	234,564	0.0685	0.9315	56.37
18.5	3,177,345	13,695	0.0043	0.9957	52.51
19.5	3,163,347		0.0000	1.0000	52.28
20.5	2,911,238		0.0000	1.0000	52.28
21.5	2,691,109	2,716	0.0010	0.9990	52.28
22.5	2,700,992		0.0000	1.0000	52.23
23.5	2,554,571	13,635	0.0053	0.9947	52.23
24.5	2,380,874	12,599	0.0053	0.9947	51.95
25.5	2,212,027	60,100	0.0272	0.9728	51.68
26.5	2,086,329		0.0000	1.0000	50.27
27.5	1,416,342		0.0000	1.0000	50.27
28.5	1,404,928		0.0000	1.0000	50.27
29.5	1,427,727		0.0000	1.0000	50.27
30.5	1,070,297	35,353	0.0330	0.9670	50.27
31.5	540,481	15,633	0.0289	0.9711	48.61
32.5	444,895		0.0000	1.0000	47.21
33.5	348,352		0.0000	1.0000	47.21
34.5	323,796		0.0000	1.0000	47.21
35.5	317,464		0.0000	1.0000	47.21
36.5	316,395		0.0000	1.0000	47.21
37.5	284,189		0.0000	1.0000	47.21
38.5	284,189		0.0000	1.0000	47.21

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 1955-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	279,124	41,657	0.1492	0.8508	47.21
40.5	214,622		0.0000	1.0000	40.16
41.5	207,163		0.0000	1.0000	40.16
42.5	142,833		0.0000	1.0000	40.16
43.5	142,206		0.0000	1.0000	40.16
44.5	95,805		0.0000	1.0000	40.16
45.5	86,801		0.0000	1.0000	40.16
46.5	82,900		0.0000	1.0000	40.16
47.5	76,594		0.0000	1.0000	40.16
48.5	76,594		0.0000	1.0000	40.16
49.5	27,605		0.0000	1.0000	40.16
50.5	27,605		0.0000	1.0000	40.16
51.5	27,605		0.0000	1.0000	40.16
52.5	27,605		0.0000	1.0000	40.16
53.5	540		0.0000	1.0000	40.16
54.5	540		0.0000	1.0000	40.16
55.5	540		0.0000	1.0000	40.16
56.5	540		0.0000	1.0000	40.16
57.5	540		0.0000	1.0000	40.16
58.5	540		0.0000	1.0000	40.16
59.5	540		0.0000	1.0000	40.16
60.5	540		0.0000	1.0000	40.16
61.5					40.16

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 1969-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,537,221		0.0000	1.0000	100.00
0.5	4,472,966	3,337	0.0007	0.9993	100.00
1.5	4,286,288	61,869	0.0144	0.9856	99.93
2.5	4,270,940	684	0.0002	0.9998	98.48
3.5	3,759,452	4,278	0.0011	0.9989	98.47
4.5	3,798,003	21,151	0.0056	0.9944	98.36
5.5	3,879,200	32,248	0.0083	0.9917	97.81
6.5	3,840,184	78,644	0.0205	0.9795	96.99
7.5	3,771,489	26,518	0.0070	0.9930	95.01
8.5	3,824,547	45,188	0.0118	0.9882	94.34
9.5	3,725,128	199,708	0.0536	0.9464	93.23
10.5	3,518,581	242,377	0.0689	0.9311	88.23
11.5	3,569,220	122,712	0.0344	0.9656	82.15
12.5	3,539,616	11,185	0.0032	0.9968	79.33
13.5	3,534,900	796,019	0.2252	0.7748	79.07
14.5	3,097,825		0.0000	1.0000	61.27
15.5	3,609,407	187,551	0.0520	0.9480	61.27
16.5	3,505,008	11,101	0.0032	0.9968	58.08
17.5	3,417,542	234,564	0.0686	0.9314	57.90
18.5	3,168,281	13,695	0.0043	0.9957	53.93
19.5	3,163,347		0.0000	1.0000	53.69
20.5	2,911,238		0.0000	1.0000	53.69
21.5	2,691,109	2,716	0.0010	0.9990	53.69
22.5	2,700,992		0.0000	1.0000	53.64
23.5	2,554,571	13,635	0.0053	0.9947	53.64
24.5	2,380,874	12,599	0.0053	0.9947	53.35
25.5	2,212,027	60,100	0.0272	0.9728	53.07
26.5	2,086,329		0.0000	1.0000	51.63
27.5	1,416,342		0.0000	1.0000	51.63
28.5	1,404,928		0.0000	1.0000	51.63
29.5	1,427,727		0.0000	1.0000	51.63
30.5	1,070,297	35,353	0.0330	0.9670	51.63
31.5	540,481	15,633	0.0289	0.9711	49.92
32.5	444,895		0.0000	1.0000	48.48
33.5	348,352		0.0000	1.0000	48.48
34.5	323,796		0.0000	1.0000	48.48
35.5	317,464		0.0000	1.0000	48.48
36.5	316,395		0.0000	1.0000	48.48
37.5	284,189		0.0000	1.0000	48.48
38.5	284,189		0.0000	1.0000	48.48

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 1969-2018

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	279,124	41,657	0.1492	0.8508	48.48
40.5	214,622		0.0000	1.0000	41.24
41.5	207,163		0.0000	1.0000	41.24
42.5	142,833		0.0000	1.0000	41.24
43.5	142,206		0.0000	1.0000	41.24
44.5	95,805		0.0000	1.0000	41.24
45.5	86,801		0.0000	1.0000	41.24
46.5	82,900		0.0000	1.0000	41.24
47.5	76,594		0.0000	1.0000	41.24
48.5	76,594		0.0000	1.0000	41.24
49.5	27,605		0.0000	1.0000	41.24
50.5	27,605		0.0000	1.0000	41.24
51.5	27,605		0.0000	1.0000	41.24
52.5	27,605		0.0000	1.0000	41.24
53.5	540		0.0000	1.0000	41.24
54.5	540		0.0000	1.0000	41.24
55.5	540		0.0000	1.0000	41.24
56.5	540		0.0000	1.0000	41.24
57.5	540		0.0000	1.0000	41.24
58.5	540		0.0000	1.0000	41.24
59.5	540		0.0000	1.0000	41.24
60.5	540		0.0000	1.0000	41.24
61.5					41.24

PART VIII. DETAILED DEPRECIATION CALCULATIONS

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 303.00 MISCELLANEOUS INTANGIBLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 7-SQUARE						
1994	3,126,826.72	3,126,827	3,126,827			
1997	56,927.57	56,928	56,928			
2000	15.23	15	15			
2001	21,010.34	21,010	21,010			
2002	222,200.49	222,200	222,200			
2003	17,767,988.03	17,767,988	17,767,988			
2004	4,354,304.86	4,354,305	4,354,305			
2005	1,431,062.97	1,431,063	1,431,063			
2006	2,276,385.54	2,276,386	2,276,386			
2007	12,557,548.81	12,557,549	12,557,549			
2008	1,140,864.29	1,140,864	1,140,864			
2009	3,819,117.52	3,819,118	3,819,118			
2010	1,946,530.27	1,946,530	1,946,530			
2011	5,171,814.82	5,171,815	5,171,815			
2012	2,393,244.86	2,307,782	2,273,366	119,879	0.25	119,879
2013	3,944,642.93	3,240,248	3,191,927	752,716	1.25	602,173
2014	11,002,459.45	7,465,939	7,354,601	3,647,858	2.25	1,621,270
2015	4,559,449.96	2,442,543	2,406,118	2,153,332	3.25	662,564
2016	7,360,628.14	2,891,696	2,848,572	4,512,056	4.25	1,061,660
2017	7,796,792.77	1,949,198	1,920,130	5,876,663	5.25	1,119,364
2018	17,017,752.39	1,823,282	1,796,092	15,221,660	6.25	2,435,466
2019	4,052,705.02	69,463	68,427	3,984,278	6.88	579,110
	112,020,272.98	76,082,749	75,751,831	36,268,442		8,201,486

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.4   7.32

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 360.12 DISTRIBUTION SUBSTATION EASEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 80-R4						
1928	183.01	165	183			
1930	100.00	90	100			
1943	1.00	1	1			
1952	203.00	153	174	29	19.51	1
1956	5,832.75	4,206	4,775	1,058	22.31	47
1957	1,017.73	725	823	195	23.03	8
1958	1,257.53	884	1,003	255	23.76	11
1959	99.69	69	78	22	24.50	1
1960	3,996.46	2,735	3,105	891	25.25	35
1963	2,527.16	1,657	1,881	646	27.56	23
1964	13,494.95	8,714	9,892	3,603	28.34	127
1965	12,421.93	7,897	8,964	3,458	29.14	119
1967	6,690.70	4,118	4,675	2,016	30.76	66
1968	8,060.51	4,878	5,537	2,524	31.59	80
1970	2,377.33	1,389	1,577	800	33.26	24
1974	1,510.61	817	927	584	36.71	16
1976	11,781.13	6,114	6,940	4,841	38.48	126
1978	13,975.33	6,939	7,877	6,098	40.28	151
1979	7.00	3	3	4	41.19	
1981	1.00			1	43.03	
1982	1.00			1	43.96	
1984	1.00			1	45.83	
1985	11,273.13	4,683	5,316	5,957	46.77	127
1988	1.00			1	49.63	
1989	1.00			1	50.59	
1990	5,614.50	1,997	2,267	3,348	51.55	65
1991	100.62	35	40	61	52.52	1
2006	203,534.24	32,362	36,737	166,797	67.28	2,479
2007	384,519.00	56,332	63,947	320,572	68.28	4,695
	690,584.31	146,963	166,822	523,762		8,202

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 63.9   1.19

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 360.22 DISTRIBUTION LINE EASEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 80-R4						
1930	2,788.84	2,499	2,789			
1931	2,988.42	2,666	2,988			
1932	1,276.22	1,133	1,276			
1933	1,382.45	1,221	1,382			
1934	1,083.92	952	1,084			
1935	927.75	811	928			
1936	2,363.57	2,053	2,364			
1937	1,095.30	946	1,095			
1938	137,331.58	117,830	137,332			
1939	8,158.44	6,952	8,158			
1940	9,668.09	8,180	9,668			
1941	10,652.77	8,947	10,653			
1942	2,870.31	2,392	2,870			
1943	20,692.30	17,105	20,692			
1944	3,736.53	3,063	3,737			
1945	3,944.63	3,205	3,945			
1946	13,891.87	11,181	13,892			
1947	9,018.41	7,189	9,018			
1948	10,384.91	8,196	10,385			
1949	13,843.28	10,813	13,843			
1950	11,248.97	8,694	11,249			
1951	14,504.71	11,089	14,505			
1952	18,393.46	13,908	18,393			
1953	18,582.66	13,891	18,583			
1954	16,504.90	12,193	16,505			
1955	23,851.38	17,412	23,851			
1956	16,749.16	12,078	16,749			
1957	48,216.75	34,336	48,217			
1958	59,956.46	42,149	59,956			
1959	81,691.25	56,673	81,691			
1960	99,468.80	68,074	99,469			
1961	109,149.28	73,663	109,149			
1962	121,881.86	81,082	121,882			
1963	143,654.96	94,166	143,655			
1964	161,307.10	104,164	161,307			
1965	178,932.71	113,756	178,933			
1966	220,883.03	138,189	220,883			
1967	237,352.36	146,090	237,352			
1968	265,514.89	160,668	265,515			
1969	267,828.12	159,291	267,828			
1970	295,491.78	172,641	293,391	2,101	33.26	63
1971	264,513.10	151,730	257,854	6,659	34.11	195
1972	371,888.06	209,328	355,738	16,150	34.97	462
1973	318,298.00	175,739	298,656	19,642	35.83	548

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 360.22 DISTRIBUTION LINE EASEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 80-R4						
1974	417,169.50	225,739	383,627	33,542	36.71	914
1975	338,779.81	179,594	305,207	33,573	37.59	893
1976	491,350.20	255,011	433,373	57,977	38.48	1,507
1977	472,206.55	239,763	407,460	64,747	39.38	1,644
1978	579,317.79	287,631	488,808	90,510	40.28	2,247
1979	789,185.02	382,849	650,624	138,561	41.19	3,364
1980	671,560.24	318,064	540,527	131,033	42.11	3,112
1981	499,457.74	230,809	392,243	107,215	43.03	2,492
1982	463,839.23	208,960	355,113	108,726	43.96	2,473
1983	840,884.70	369,047	627,169	213,716	44.89	4,761
1984	1,701,196.11	726,615	1,234,830	466,366	45.83	10,176
1985	643,386.53	267,250	454,172	189,215	46.77	4,046
1986	1,258,408.13	507,768	862,915	395,493	47.72	8,288
1987	881,132.46	345,069	586,420	294,712	48.67	6,055
1988	1,091,928.12	414,518	704,444	387,484	49.63	7,807
1989	865,120.75	318,036	540,479	324,642	50.59	6,417
1990	1,015,041.51	360,969	613,441	401,601	51.55	7,791
1991	1,501,280.76	515,690	876,378	624,903	52.52	11,898
1992	1,643,685.61	544,685	925,653	718,033	53.49	13,424
1993	1,600,930.86	511,097	868,573	732,358	54.46	13,448
1994	613,583.49	188,370	320,121	293,462	55.44	5,293
1995	670,391.39	197,685	335,951	334,440	56.41	5,929
1996	270,316.85	76,397	129,831	140,486	57.39	2,448
1997	821,919.92	222,124	377,484	444,436	58.38	7,613
1998	1,342,650.46	346,404	588,689	753,961	59.36	12,701
2000	1,113,920.56	259,967	441,795	672,126	61.33	10,959
2002	2,252.46	470	799	1,453	63.31	23
2003	25,800.30	5,063	8,604	17,196	64.30	267
2010	5,162.49	563	957	4,205	71.27	59
	26,255,822.88	10,794,545	18,035,097	8,220,726		159,317

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 51.6 0.61

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
1896	17,563.36	17,563	17,563			
1901	3,483.19	3,483	3,483			
1905	28,908.31	28,908	28,908			
1910	4,015.77	4,016	4,016			
1911	196.83	197	197			
1912	10,357.35	10,332	10,357			
1922	962.90	934	963			
1923	13,523.79	13,070	13,524			
1924	1,450.07	1,397	1,450			
1925	20,868.07	20,024	20,868			
1926	6,945.69	6,641	6,946			
1927	21,715.95	20,686	21,716			
1928	7,777.41	7,381	7,777			
1929	1,625.84	1,537	1,626			
1930	5,559.57	5,235	5,560			
1931	23,277.08	21,831	23,277			
1932	3,536.77	3,303	3,537			
1933	1,150.45	1,070	1,150			
1934	78.84	73	79			
1935	168.81	156	169			
1936	53.70	49	54			
1937	1,025.27	937	1,025			
1938	562.27	512	562			
1939	1,426.23	1,292	1,426			
1940	8,996.64	8,109	8,997			
1941	2,299.03	2,062	2,299			
1942	9,467.26	8,445	9,467			
1943	7,798.31	6,917	7,798			
1946	77.19	67	77			
1947	36,874.82	31,892	36,875			
1948	19,198.52	16,483	19,199			
1949	4,638.44	3,952	4,638			
1950	125,978.01	106,469	125,978			
1951	74,998.75	62,838	74,999			
1952	51,263.73	42,564	51,264			
1953	80,028.61	65,818	80,029			
1954	21,480.91	17,488	21,481			
1955	156,827.68	126,358	156,828			
1956	182,594.96	145,503	182,595			
1957	80,202.25	63,188	80,202			
1958	100,859.16	78,526	100,859			
1959	106,534.07	81,925	106,534			
1960	92,133.20	69,969	92,133			
1961	82,669.02	61,966	82,669			

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
1962	161,783.85	119,673	161,784			
1963	61,155.57	44,626	61,156			
1964	161,481.82	116,175	160,149	1,333	19.64	68
1965	109,505.32	77,655	107,049	2,456	20.36	121
1966	238,149.81	166,398	229,383	8,767	21.09	416
1967	212,231.42	146,015	201,284	10,947	21.84	501
1968	431,458.65	292,223	402,835	28,624	22.59	1,267
1969	460,787.09	307,018	423,230	37,557	23.36	1,608
1970	512,673.28	335,873	463,007	49,666	24.14	2,057
1971	620,656.08	399,703	550,998	69,658	24.92	2,795
1972	242,757.92	153,561	211,687	31,071	25.72	1,208
1973	240,804.08	149,539	206,142	34,662	26.53	1,307
1974	113,280.31	69,021	95,147	18,133	27.35	663
1975	233,555.86	139,533	192,349	41,207	28.18	1,462
1976	148,005.43	86,647	119,444	28,561	29.02	984
1977	80,899.09	46,379	63,934	16,965	29.87	568
1978	112,631.03	63,186	87,103	25,528	30.73	831
1979	128,146.00	70,297	96,906	31,240	31.60	989
1980	46,615.34	24,986	34,444	12,171	32.48	375
1981	18,492.22	9,679	13,343	5,149	33.36	154
1982	204,778.77	104,554	144,130	60,649	34.26	1,770
1983	115,905.93	57,688	79,524	36,382	35.16	1,035
1984	237,075.15	114,913	158,410	78,665	36.07	2,181
1985	326,515.31	153,975	212,257	114,258	36.99	3,089
1986	808,934.09	370,840	511,210	297,724	37.91	7,853
1987	1,228,040.37	546,650	753,567	474,473	38.84	12,216
1988	711,400.49	307,119	423,369	288,031	39.78	7,241
1989	1,621,070.85	678,078	934,742	686,329	40.72	16,855
1990	277,420.97	112,317	154,831	122,590	41.66	2,943
1991	356,884.16	139,592	192,430	164,454	42.62	3,859
1992	2,490,704.99	940,415	1,296,379	1,194,326	43.57	27,412
1993	443,117.50	161,233	222,263	220,854	44.53	4,960
1994	127,145.21	44,501	61,345	65,800	45.50	1,446
1995	612,644.57	205,934	283,884	328,761	46.47	7,075
1996	1,207,365.27	389,122	536,411	670,954	47.44	14,143
1998	111,879.87	32,941	45,410	66,470	49.39	1,346
1999	1,910.27	536	739	1,171	50.37	23
2002	6,795.20	1,618	2,230	4,565	53.33	86
2005	1,387,169.96	271,483	374,244	1,012,926	56.30	17,992
2006	363,360.16	65,975	90,948	272,412	57.29	4,755
2007	602,618.52	100,896	139,087	463,532	58.28	7,954
2008	718,047.46	109,962	151,585	566,462	59.28	9,556
2009	106,675.57	14,828	20,441	86,235	60.27	1,431
2010	49,362.33	6,156	8,486	40,876	61.27	667

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
2011	100,655.74	11,130	15,343	85,313	62.26	1,370
2012	584,593.11	56,290	77,597	506,996	63.26	8,014
2013	547,604.58	44,904	61,901	485,704	64.26	7,558
2015	658,952.98	35,300	48,661	610,292	66.25	9,212
2016	3,913,926.93	153,778	211,985	3,701,942	67.25	55,047
2017	762,076.83	19,052	26,264	735,813	68.25	10,781
2018	487,031.49	5,216	7,190	479,841	69.25	6,929
	26,927,888.88	9,246,349	12,549,391	14,378,498		274,173

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 52.4 1.02

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.20 STRUCTURES AND IMPROVEMENTS - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
1956	16,369.44	13,044	16,369			
2006	66,892.56	12,146	16,505	50,388	57.29	880
2007	924,656.01	154,815	210,372	714,284	58.28	12,256
2008	65,125.23	9,973	13,552	51,573	59.28	870
2009	189,807.78	26,383	35,851	153,957	60.27	2,554
2010	165,692.99	20,664	28,079	137,614	61.27	2,246
2012	573,887.19	55,260	75,091	498,796	63.26	7,885
2014	2,317,982.26	156,951	213,274	2,104,708	65.26	32,251
2016	9,424,155.07	370,275	503,152	8,921,003	67.25	132,654
2019	5,872,613.25	10,042	13,646	5,858,967	69.88	83,843
	19,617,181.78	829,553	1,125,891	18,491,291		275,439

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 67.1   1.40

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 59-R2						
1914	49.67	49	50			
1915	50.13	49	50			
1917	62.11	60	62			
1918	57.54	55	58			
1919	349.23	334	349			
1920	130.07	124	130			
1921	252.91	239	253			
1922	764.27	720	764			
1923	4,134.55	3,875	4,135			
1924	899.75	839	900			
1925	2,963.97	2,749	2,964			
1926	9,265.01	8,547	9,265			
1927	17,145.83	15,734	17,146			
1928	15,445.92	14,098	15,446			
1929	12,997.33	11,799	12,997			
1930	10,388.55	9,380	10,389			
1931	52,309.40	46,972	52,309			
1932	7,945.87	7,095	7,946			
1933	13,373.42	11,875	13,373			
1934	1,269.93	1,121	1,270			
1935	8,408.36	7,382	8,408			
1936	13,585.93	11,861	13,586			
1937	55,132.63	47,853	55,133			
1938	7,042.40	6,076	7,042			
1939	8,408.93	7,212	8,409			
1940	30,228.26	25,766	30,228			
1941	32,654.80	27,657	32,655			
1942	57,451.44	48,347	57,451			
1943	13,942.75	11,658	13,943			
1944	1,946.94	1,617	1,947			
1945	683.63	564	684			
1946	681.56	558	682			
1947	57,595.84	46,819	57,596			
1948	189,763.15	153,097	189,763			
1949	122,156.26	97,787	122,156			
1950	303,516.47	241,013	303,516			
1951	593,727.09	467,536	593,727			
1952	254,231.97	198,517	252,938	1,294	12.93	100
1953	471,634.06	364,998	465,057	6,577	13.34	493
1954	600,098.07	460,245	586,415	13,683	13.75	995
1955	928,072.81	705,178	898,493	29,580	14.17	2,088
1956	978,170.01	735,946	937,696	40,474	14.61	2,770
1957	1,101,266.23	820,355	1,045,244	56,022	15.05	3,722
1958	1,439,503.63	1,061,332	1,352,282	87,222	15.50	5,627

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 59-R2						
1959	1,061,953.81	774,504	986,824	75,130	15.97	4,704
1960	1,103,921.14	796,325	1,014,627	89,294	16.44	5,432
1961	699,319.24	498,768	635,499	63,820	16.92	3,772
1962	1,220,714.84	860,299	1,096,138	124,577	17.42	7,151
1963	670,844.64	467,089	595,135	75,710	17.92	4,225
1964	1,792,097.41	1,232,300	1,570,118	221,979	18.43	12,044
1965	1,410,426.89	957,172	1,219,568	190,859	18.96	10,066
1966	2,730,296.92	1,828,371	2,329,594	400,703	19.49	20,559
1967	4,016,179.39	2,652,044	3,379,066	637,113	20.04	31,792
1968	4,498,314.66	2,928,493	3,731,300	767,015	20.59	37,252
1969	5,818,572.21	3,732,789	4,756,083	1,062,489	21.15	50,236
1970	6,099,115.32	3,852,750	4,908,929	1,190,186	21.73	54,772
1971	6,461,649.05	4,018,241	5,119,788	1,341,861	22.31	60,146
1972	5,792,009.86	3,543,899	4,515,411	1,276,599	22.90	55,747
1973	6,502,100.81	3,912,249	4,984,739	1,517,362	23.50	64,569
1974	2,470,581.99	1,461,003	1,861,517	609,065	24.11	25,262
1975	4,112,413.10	2,388,695	3,043,524	1,068,889	24.73	43,222
1976	1,559,331.36	889,084	1,132,814	426,517	25.36	16,818
1977	851,363.48	476,185	606,725	244,638	26.00	9,409
1978	1,404,269.92	769,975	981,053	423,217	26.65	15,881
1979	5,245,068.71	2,818,123	3,590,673	1,654,396	27.30	60,601
1980	2,915,906.15	1,533,563	1,953,969	961,937	27.97	34,392
1981	280,014.22	144,090	183,590	96,424	28.64	3,367
1982	5,392,912.04	2,712,904	3,456,610	1,936,302	29.32	66,040
1983	1,068,570.50	525,053	668,989	399,582	30.01	13,315
1984	1,471,107.33	705,631	899,070	572,037	30.70	18,633
1985	5,007,145.11	2,341,491	2,983,379	2,023,766	31.41	64,431
1986	3,835,311.06	1,747,329	2,226,336	1,608,975	32.12	50,093
1987	7,871,973.33	3,490,354	4,447,187	3,424,786	32.84	104,287
1988	12,781,665.08	5,509,153	7,019,413	5,762,252	33.57	171,649
1989	8,528,803.01	3,570,498	4,549,302	3,979,501	34.30	116,020
1990	3,853,168.73	1,564,772	1,993,733	1,859,436	35.04	53,066
1991	9,414,741.88	3,703,665	4,718,975	4,695,767	35.79	131,203
1992	23,537,558.69	8,956,276	11,411,518	12,126,041	36.55	331,766
1993	20,580,678.21	7,566,075	9,640,213	10,940,465	37.31	293,231
1994	2,876,307.48	1,019,881	1,299,468	1,576,839	38.08	41,409
1995	8,833,389.79	3,015,366	3,841,988	4,991,402	38.86	128,446
1996	13,714,440.72	4,500,257	5,733,942	7,980,499	39.64	201,324
1997	4,083,657.76	1,285,331	1,637,687	2,445,971	40.43	60,499
1998	11,964,646.10	3,603,632	4,591,519	7,373,127	41.23	178,829
1999	3,045,008.75	875,836	1,115,935	1,929,074	42.03	45,898
2000	17,029,658.90	4,664,424	5,943,113	11,086,546	42.84	258,790
2001	18,350,103.25	4,774,146	6,082,914	12,267,189	43.65	281,035
2002	18,317,383.32	4,511,022	5,747,658	12,569,725	44.47	282,656

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 59-R2						
2003	6,456,894.35	1,499,291	1,910,301	4,546,593	45.30	100,366
2004	9,743,324.01	2,125,409	2,708,061	7,035,263	46.13	152,509
2005	23,561,813.24	4,804,254	6,121,275	17,440,538	46.97	371,312
2006	12,034,554.91	2,282,474	2,908,184	9,126,371	47.81	190,888
2007	21,061,340.18	3,691,000	4,702,838	16,358,502	48.66	336,180
2008	19,080,666.80	3,069,125	3,910,484	15,170,183	49.51	306,406
2009	10,804,135.12	1,580,321	2,013,545	8,790,590	50.37	174,520
2010	9,397,196.10	1,236,013	1,574,849	7,822,347	51.24	152,661
2011	17,297,011.18	2,022,885	2,577,432	14,719,579	52.10	282,526
2012	14,581,795.99	1,487,781	1,895,636	12,686,160	52.98	239,452
2013	15,527,358.19	1,352,743	1,723,579	13,803,779	53.86	256,290
2014	12,845,814.30	927,468	1,181,721	11,664,093	54.74	213,082
2015	17,057,873.28	974,346	1,241,450	15,816,423	55.63	284,315
2016	19,216,059.92	807,651	1,029,057	18,187,003	56.52	321,780
2017	12,684,901.34	339,702	432,827	12,252,074	57.42	213,376
2018	7,071,563.53	81,535	103,887	6,967,677	58.32	119,473
2019	3,126,858.64	5,816	7,410	3,119,449	58.89	52,971
	509,243,615.92	147,152,009	187,433,076	321,810,540		7,307,941

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.0   1.44

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 49-R1.5						
1943	616,159.09	536,564	616,159			
1944	32,343.04	27,980	32,343			
1945	56,686.99	48,728	56,687			
1946	125,594.48	107,216	125,594			
1947	176,683.88	149,821	176,684			
1948	214,986.54	181,027	214,987			
1949	285,330.41	238,513	285,330			
1950	70,833.05	58,777	70,520	313	8.34	38
1951	338,647.05	278,933	334,659	3,988	8.64	462
1952	70,377.50	57,523	69,015	1,362	8.95	152
1953	382,941.91	310,497	372,529	10,413	9.27	1,123
1954	419,137.93	337,108	404,457	14,681	9.59	1,531
1955	738,083.49	588,658	706,262	31,821	9.92	3,208
1956	713,614.98	564,341	677,087	36,528	10.25	3,564
1957	907,925.66	711,514	853,663	54,263	10.60	5,119
1958	885,179.80	687,546	824,906	60,274	10.94	5,510
1959	1,010,785.69	777,688	933,057	77,729	11.30	6,879
1960	1,159,217.96	883,139	1,059,575	99,643	11.67	8,538
1961	1,343,782.02	1,013,601	1,216,102	127,680	12.04	10,605
1962	1,865,373.00	1,392,184	1,670,319	195,054	12.43	15,692
1963	2,554,635.41	1,886,266	2,263,110	291,525	12.82	22,740
1964	2,781,487.66	2,030,486	2,436,143	345,345	13.23	26,103
1965	3,210,810.86	2,317,017	2,779,918	430,893	13.64	31,590
1966	3,292,353.89	2,346,987	2,815,876	476,478	14.07	33,865
1967	3,647,438.45	2,568,088	3,081,149	566,289	14.50	39,054
1968	3,827,487.28	2,659,721	3,191,089	636,398	14.95	42,568
1969	4,037,388.62	2,768,478	3,321,574	715,815	15.40	46,481
1970	2,779,488.48	1,879,268	2,254,714	524,774	15.87	33,067
1971	3,601,802.69	2,399,989	2,879,467	722,336	16.35	44,180
1972	4,999,715.01	3,281,463	3,937,045	1,062,670	16.84	63,104
1973	4,225,488.70	2,731,060	3,276,680	948,809	17.33	54,750
1974	4,331,370.86	2,754,405	3,304,689	1,026,682	17.84	57,549
1975	2,927,243.09	1,830,434	2,196,124	731,119	18.36	39,821
1976	3,082,243.30	1,893,391	2,271,659	810,584	18.90	42,888
1977	2,658,476.52	1,603,779	1,924,187	734,290	19.44	37,772
1978	3,411,024.40	2,019,463	2,422,918	988,106	19.99	49,430
1979	4,457,571.98	2,588,111	3,105,172	1,352,400	20.55	65,810
1980	4,505,972.98	2,563,809	3,076,015	1,429,958	21.12	67,706
1981	4,288,152.61	2,389,101	2,866,404	1,421,749	21.70	65,518
1982	3,573,690.28	1,948,019	2,337,201	1,236,489	22.29	55,473
1983	3,972,869.90	2,116,983	2,539,921	1,432,949	22.89	62,602
1984	4,220,134.82	2,196,200	2,634,964	1,585,171	23.50	67,454
1985	7,365,000.00	3,739,652	4,486,772	2,878,228	24.12	119,330
1986	8,135,781.64	4,026,398	4,830,805	3,304,977	24.75	133,534

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 49-R1.5						
1987	8,334,791.04	4,016,036	4,818,373	3,516,418	25.39	138,496
1988	11,293,674.27	5,294,249	6,351,952	4,941,722	26.03	189,847
1989	9,752,093.63	4,440,226	5,327,309	4,424,785	26.69	165,784
1990	10,560,267.29	4,665,948	5,598,127	4,962,140	27.35	181,431
1991	13,350,495.15	5,716,148	6,858,139	6,492,356	28.02	231,704
1992	11,526,446.77	4,775,292	5,729,316	5,797,131	28.70	201,991
1993	12,153,944.94	4,866,561	5,838,819	6,315,126	29.38	214,946
1994	13,163,156.44	5,085,322	6,101,284	7,061,872	30.07	234,848
1995	14,229,682.40	5,294,011	6,351,666	7,878,016	30.77	256,029
1996	16,897,442.62	6,041,681	7,248,708	9,648,735	31.48	306,504
1997	19,696,973.13	6,757,244	8,107,229	11,589,744	32.19	360,042
1998	29,001,081.60	9,523,085	11,425,639	17,575,443	32.91	534,046
1999	11,694,321.15	3,665,819	4,398,188	7,296,133	33.64	216,889
2000	13,959,617.34	4,167,923	5,000,604	8,959,013	34.37	260,664
2001	20,260,198.62	5,747,211	6,895,408	13,364,791	35.10	380,763
2002	11,162,241.21	2,997,843	3,596,762	7,565,479	35.84	211,090
2003	9,998,771.78	2,532,389	3,038,318	6,960,454	36.59	190,228
2004	18,241,632.58	4,340,779	5,207,994	13,033,639	37.34	349,053
2005	15,288,337.07	3,400,891	4,080,332	11,208,005	38.10	294,173
2006	19,667,686.52	4,070,031	4,883,155	14,784,532	38.86	380,456
2007	8,138,858.51	1,556,313	1,867,238	6,271,621	39.63	158,254
2008	17,898,602.38	3,141,384	3,768,980	14,129,622	40.40	349,743
2009	15,105,367.41	2,410,666	2,892,277	12,213,090	41.18	296,578
2010	17,604,689.96	2,529,266	3,034,571	14,570,119	41.96	347,238
2011	14,386,799.18	1,835,036	2,201,646	12,185,153	42.75	285,033
2012	120,379,062.32	13,413,839	16,093,701	104,285,361	43.54	2,395,162
2013	12,366,154.54	1,178,618	1,414,086	10,952,069	44.33	247,058
2014	16,663,835.95	1,316,110	1,579,047	15,084,789	45.13	334,252
2015	14,108,152.13	881,054	1,057,074	13,051,078	45.94	284,090
2016	18,399,915.92	844,924	1,013,726	17,386,190	46.75	371,897
2017	14,602,138.64	429,157	514,896	14,087,243	47.56	296,199
2018	43,830,574.98	554,457	665,228	43,165,347	48.38	892,215
2019	10,680,253.70	21,788	26,141	10,654,113	48.90	217,876
	721,698,575.07	195,001,227	233,919,464	487,779,111		13,139,389

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.1   1.82

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 37-R1						
1943	20,291.13	20,291	20,291			
1944	1,521.97	1,522	1,522			
1945	2,983.84	2,965	2,057	927	0.23	927
1946	6,600.32	6,504	4,512	2,088	0.54	2,088
1947	11,287.52	11,022	7,646	3,642	0.87	3,642
1948	14,700.30	14,224	9,867	4,833	1.20	4,028
1949	21,342.88	20,455	14,189	7,154	1.54	4,645
1950	25,966.52	24,654	17,102	8,865	1.87	4,741
1951	39,813.22	37,457	25,984	13,829	2.19	6,315
1952	43,607.26	40,661	28,206	15,401	2.50	6,160
1953	70,262.72	64,945	45,052	25,211	2.80	9,004
1954	102,545.81	93,955	65,176	37,370	3.10	12,055
1955	162,744.97	147,834	102,551	60,194	3.39	17,756
1956	200,484.57	180,490	125,205	75,280	3.69	20,401
1957	324,813.88	289,786	201,022	123,792	3.99	31,026
1958	294,262.87	260,064	180,404	113,859	4.30	26,479
1959	328,587.10	287,648	199,539	129,048	4.61	27,993
1960	474,795.11	411,533	285,477	189,318	4.93	38,401
1961	567,932.66	487,195	337,963	229,970	5.26	43,721
1962	671,693.68	570,214	395,553	276,141	5.59	49,399
1963	652,020.28	547,697	379,933	272,087	5.92	45,961
1964	1,012,263.41	840,725	583,205	429,058	6.27	68,430
1965	1,458,675.25	1,197,689	830,828	627,847	6.62	94,841
1966	1,677,539.60	1,361,525	944,479	733,061	6.97	105,174
1967	1,970,386.97	1,579,502	1,095,688	874,699	7.34	119,169
1968	1,990,774.27	1,575,937	1,093,215	897,559	7.71	116,415
1969	1,950,208.15	1,523,795	1,057,045	893,163	8.09	110,403
1970	1,727,816.08	1,332,284	924,195	803,621	8.47	94,879
1971	1,997,156.48	1,518,917	1,053,661	943,495	8.86	106,489
1972	2,168,605.53	1,625,869	1,127,853	1,040,753	9.26	112,392
1973	2,000,492.05	1,477,663	1,025,044	975,448	9.67	100,874
1974	2,171,202.76	1,579,116	1,095,421	1,075,782	10.09	106,619
1975	1,743,583.25	1,248,318	865,949	877,634	10.51	83,505
1976	1,733,296.92	1,220,796	846,857	886,440	10.94	81,027
1977	1,460,780.72	1,011,488	701,661	759,120	11.38	66,707
1978	2,157,375.26	1,467,598	1,018,062	1,139,313	11.83	96,307
1979	2,996,929.87	2,001,470	1,388,404	1,608,526	12.29	130,881
1980	3,183,253.63	2,086,336	1,447,275	1,735,979	12.75	136,155
1981	2,553,104.83	1,640,191	1,137,788	1,415,317	13.23	106,978
1982	1,990,567.35	1,252,983	869,185	1,121,382	13.71	81,793
1983	2,427,467.51	1,495,854	1,037,662	1,389,806	14.20	97,874
1984	2,389,608.68	1,439,572	998,620	1,390,989	14.71	94,561
1985	3,437,032.12	2,023,209	1,403,485	2,033,547	15.22	133,610
1986	5,276,606.18	3,031,885	2,103,195	3,173,411	15.74	201,614

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 37-R1						
1987	6,100,199.67	3,417,759	2,370,873	3,729,327	16.27	229,215
1988	9,154,604.67	4,995,485	3,465,330	5,689,275	16.81	338,446
1989	8,775,429.82	4,658,086	3,231,279	5,544,151	17.36	319,364
1990	9,032,237.30	4,657,744	3,231,041	5,801,196	17.92	323,727
1991	13,660,466.01	6,837,610	4,743,198	8,917,268	18.48	482,536
1992	11,963,220.38	5,800,487	4,023,753	7,939,467	19.06	416,551
1993	11,238,210.65	5,269,822	3,655,635	7,582,576	19.65	385,882
1994	11,632,041.97	5,268,966	3,655,041	7,977,001	20.24	394,121
1995	12,309,222.54	5,372,853	3,727,107	8,582,116	20.85	411,612
1996	9,816,498.88	4,122,930	2,860,045	6,956,454	21.46	324,159
1997	12,244,086.84	4,937,306	3,424,971	8,819,116	22.08	399,416
1998	31,599,162.18	12,204,228	8,465,980	23,133,182	22.71	1,018,634
1999	13,755,654.73	5,078,450	3,522,882	10,232,773	23.34	438,422
2000	14,210,900.32	4,996,837	3,466,268	10,744,632	23.99	447,880
2001	18,380,391.71	6,139,970	4,259,250	14,121,142	24.64	573,098
2002	12,084,434.44	3,824,603	2,653,098	9,431,336	25.29	372,927
2003	14,948,295.84	4,464,309	3,096,857	11,851,439	25.95	456,703
2004	18,120,084.46	5,083,408	3,526,321	14,593,763	26.62	548,226
2005	16,722,466.88	4,388,477	3,044,253	13,678,214	27.29	501,217
2006	30,652,024.84	7,480,627	5,189,254	25,462,771	27.97	910,360
2007	18,273,632.49	4,123,993	2,860,782	15,412,850	28.65	537,970
2008	23,781,544.40	4,923,493	3,415,390	20,366,154	29.34	694,143
2009	26,963,570.72	5,086,678	3,528,590	23,434,981	30.02	780,646
2010	27,642,212.62	4,691,713	3,254,605	24,387,608	30.72	793,867
2011	24,003,001.13	3,626,373	2,515,587	21,487,414	31.41	684,095
2012	193,271,220.92	25,490,541	17,682,594	175,588,627	32.12	5,466,645
2013	26,994,610.85	3,049,581	2,115,471	24,879,140	32.82	758,048
2014	41,251,071.10	3,857,388	2,675,841	38,575,230	33.54	1,150,126
2015	37,486,409.81	2,785,990	1,932,620	35,553,790	34.25	1,038,067
2016	42,637,631.42	2,327,588	1,614,630	41,023,001	34.98	1,172,756
2017	29,970,375.63	1,044,767	724,747	29,245,629	35.71	818,976
2018	63,790,164.46	965,783	669,956	63,120,208	36.44	1,732,168
2019	5,400,598.70	13,123	9,103	5,391,496	36.91	146,071
	903,378,663.86	210,040,806	145,710,380	757,668,284		27,867,513

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.2 3.08

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R5						
1943	24,873.32	23,706	24,069	804	3.05	264
1944	3,111.70	2,955	3,000	112	3.27	34
1945	19,865.74	18,799	19,087	779	3.49	223
1946	52,641.58	49,613	50,372	2,270	3.74	607
1947	59,871.67	56,178	57,038	2,834	4.01	707
1948	51,228.34	47,840	48,572	2,656	4.30	618
1949	51,058.62	47,429	48,155	2,904	4.62	629
1950	39,217.14	36,224	36,778	2,439	4.96	492
1951	53,958.21	49,542	50,300	3,658	5.32	688
1952	60,893.60	55,544	56,394	4,500	5.71	788
1953	74,662.42	67,621	68,656	6,006	6.13	980
1954	58,860.75	52,911	53,721	5,140	6.57	782
1955	88,437.81	78,859	80,066	8,372	7.04	1,189
1956	68,406.96	60,482	61,408	6,999	7.53	929
1957	70,244.19	61,544	62,486	7,758	8.05	964
1958	199,742.23	173,284	175,936	23,806	8.61	2,765
1959	360,047.08	309,144	313,875	46,172	9.19	5,024
1960	278,974.78	236,914	240,539	38,436	9.80	3,922
1961	322,865.21	271,058	275,206	47,659	10.43	4,569
1962	508,033.67	421,353	427,801	80,233	11.09	7,235
1963	443,089.37	362,788	368,339	74,750	11.78	6,346
1964	728,905.90	588,730	597,739	131,167	12.50	10,493
1965	396,960.48	316,104	320,941	76,019	13.24	5,742
1966	480,839.92	377,277	383,050	97,790	14.00	6,985
1967	825,043.56	637,313	647,065	177,979	14.79	12,034
1968	773,237.43	587,776	596,770	176,467	15.59	11,319
1969	1,166,188.75	871,586	884,923	281,266	16.42	17,129
1970	783,686.77	575,712	584,522	199,165	17.25	11,546
1971	735,036.97	530,241	538,355	196,682	18.11	10,860
1972	876,066.33	620,255	629,746	246,320	18.98	12,978
1973	868,262.14	602,843	612,068	256,194	19.87	12,894
1974	728,678.86	495,837	503,424	225,255	20.77	10,845
1975	371,872.24	247,838	251,631	120,241	21.68	5,546
1976	373,375.13	243,556	247,283	126,092	22.60	5,579
1977	380,804.83	242,896	246,613	134,192	23.54	5,701
1978	449,398.95	280,146	284,433	164,966	24.48	6,739
1979	1,078,829.48	656,759	666,809	412,020	25.43	16,202
1980	896,678.78	532,627	540,777	355,902	26.39	13,486
1981	580,411.94	336,192	341,337	239,075	27.35	8,741
1982	466,939.55	263,424	267,455	199,485	28.33	7,041
1983	459,402.38	252,249	256,109	203,293	29.31	6,936
1984	593,622.00	316,994	321,845	271,777	30.29	8,972
1985	399,778.74	207,393	210,567	189,212	31.28	6,049
1986	964,510.61	485,670	493,102	471,409	32.27	14,608

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R5						
1987	608,978.33	297,370	301,920	307,058	33.26	9,232
1988	842,037.99	398,217	404,311	437,727	34.26	12,777
1989	749,403.12	342,994	348,243	401,160	35.25	11,380
1990	460,983.61	203,898	207,018	253,966	36.25	7,006
1991	852,903.84	364,122	369,694	483,210	37.25	12,972
1992	1,193,905.91	491,340	498,859	695,047	38.25	18,171
1993	961,226.97	380,790	386,617	574,610	39.25	14,640
1994	805,378.47	306,664	311,357	494,021	40.25	12,274
1995	809,248.56	295,683	300,208	509,041	41.25	12,340
1996	1,376,653.51	481,829	489,202	887,452	42.25	21,005
1997	1,079,711.61	361,293	366,822	712,890	43.25	16,483
1998	2,756,678.40	880,014	893,480	1,863,198	44.25	42,106
1999	894,038.69	271,654	275,811	618,228	45.25	13,662
2000	362,847.59	104,667	106,269	256,579	46.25	5,548
2001	425,381.90	116,163	117,941	307,441	47.25	6,507
2002	344,701.69	88,826	90,185	254,517	48.25	5,275
2003	86,260.22	20,902	21,222	65,038	49.25	1,321
2004	4,767,803.92	1,081,910	1,098,466	3,669,338	50.25	73,022
2006	2,902,305.84	569,287	577,998	2,324,308	52.25	44,484
2007	831,389.68	150,290	152,590	678,800	53.25	12,747
2008	4,814,086.85	796,154	808,337	4,005,750	54.25	73,839
2009	20,770,175.05	3,115,526	3,163,200	17,606,975	55.25	318,678
2010	6,039,112.92	812,985	825,425	5,213,688	56.25	92,688
2011	9,667,920.50	1,152,706	1,170,345	8,497,576	57.25	148,429
2013	42,095,095.76	3,723,732	3,780,713	38,314,383	59.25	646,656
2014	11,361,929.53	830,330	843,036	10,518,894	60.25	174,587
2015	3,864,968.43	222,970	226,382	3,638,586	61.25	59,405
2016	959,467.34	40,595	41,216	918,251	62.25	14,751
2017	19,119,780.18	514,704	522,580	18,597,200	63.25	294,027
2018	15,605,713.33	180,090	182,846	15,422,867	64.25	240,045
2019	4,550,388.48	9,101	9,240	4,541,148	64.87	70,004
	180,229,094.35	31,360,012	31,839,895	148,389,199		2,754,241

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 53.9 1.53

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
1943	855,709.64	734,430	855,710			
1945	771.55	652	772			
1946	3,243.64	2,721	3,244			
1947	7,402.92	6,159	7,403			
1948	6,289.28	5,187	6,289			
1949	18,376.23	15,015	18,376			
1951	44,977.80	36,030	44,978			
1952	21,626.23	17,145	21,626			
1953	47,175.46	36,998	47,175			
1954	83,513.99	64,763	83,514			
1955	130,712.78	100,214	130,713			
1956	158,683.97	120,219	158,684			
1957	598,401.90	447,922	598,402			
1958	394,718.75	291,776	394,719			
1959	227,682.12	166,178	226,786	896	20.26	44
1960	236,605.65	170,451	232,617	3,989	20.97	190
1961	215,124.31	152,882	208,641	6,483	21.70	299
1962	340,020.27	238,330	325,253	14,767	22.43	658
1963	290,942.05	201,061	274,391	16,551	23.17	714
1964	144,939.67	98,714	134,717	10,223	23.92	427
1965	170,377.52	114,311	156,002	14,376	24.68	582
1966	456,917.28	301,808	411,882	45,035	25.46	1,769
1967	406,627.51	264,361	360,778	45,850	26.24	1,747
1968	743,684.24	475,660	649,141	94,543	27.03	3,498
1969	536,978.03	337,722	460,895	76,083	27.83	2,734
1970	639,893.38	395,454	539,683	100,210	28.65	3,498
1971	586,624.19	356,122	486,005	100,619	29.47	3,414
1972	361,174.47	215,260	293,769	67,405	30.30	2,225
1973	2,340,769.06	1,368,882	1,868,136	472,633	31.14	15,178
1974	2,045,828.37	1,173,221	1,601,114	444,714	31.99	13,902
1975	1,301,649.23	731,527	998,327	303,322	32.85	9,234
1976	2,097,906.32	1,154,688	1,575,822	522,084	33.72	15,483
1977	878,855.50	473,527	646,230	232,626	34.59	6,725
1978	1,333,680.21	702,756	959,063	374,617	35.48	10,559
1979	1,831,735.09	943,472	1,287,572	544,163	36.37	14,962
1980	1,224,518.54	616,019	840,691	383,828	37.27	10,299
1981	1,443,941.73	709,076	967,688	476,254	38.17	12,477
1982	1,263,797.26	605,106	825,798	437,999	39.09	11,205
1983	1,430,193.08	667,228	910,577	519,616	40.01	12,987
1984	1,502,892.79	682,719	931,718	571,175	40.93	13,955
1985	2,623,921.12	1,159,432	1,582,296	1,041,625	41.86	24,884
1986	2,777,299.27	1,192,378	1,627,258	1,150,041	42.80	26,870
1987	2,721,121.19	1,134,163	1,547,811	1,173,310	43.74	26,825
1988	4,172,806.70	1,686,356	2,301,397	1,871,410	44.69	41,875

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
1989	3,608,566.68	1,412,646	1,927,861	1,680,706	45.64	36,825
1990	2,806,242.95	1,062,640	1,450,202	1,356,041	46.60	29,100
1991	4,184,770.49	1,531,082	2,089,492	2,095,278	47.56	44,055
1992	3,772,176.04	1,331,842	1,817,586	1,954,590	48.52	40,284
1993	4,154,113.81	1,412,939	1,928,261	2,225,853	49.49	44,976
1994	6,709,942.54	2,195,493	2,996,225	3,713,718	50.46	73,597
1995	12,259,729.87	3,851,149	5,255,725	7,004,005	51.44	136,159
1996	6,348,756.53	1,912,245	2,609,672	3,739,085	52.41	71,343
1997	4,943,683.65	1,424,424	1,943,934	2,999,750	53.39	56,186
1998	6,716,079.56	1,847,392	2,521,166	4,194,914	54.37	77,155
1999	721,569.22	188,957	257,873	463,696	55.36	8,376
2000	2,367,920.00	589,138	804,006	1,563,914	56.34	27,759
2001	5,035,125.19	1,186,275	1,618,929	3,416,196	57.33	59,588
2002	5,684,343.51	1,264,198	1,725,271	3,959,073	58.32	67,885
2003	1,253,303.81	262,191	357,816	895,488	59.31	15,098
2004	123,776.36	24,260	33,108	90,668	60.30	1,504
2005	316,942.38	57,937	79,068	237,874	61.29	3,881
2006	368,187.00	62,445	85,220	282,967	62.28	4,543
2007	189,387.74	29,596	40,390	148,998	63.28	2,355
2008	413,152.61	59,110	80,668	332,485	64.27	5,173
2009	835,786.14	108,427	147,972	687,814	65.27	10,538
2010	263,180.93	30,634	41,807	221,374	66.27	3,340
2011	779,715.34	80,467	109,815	669,900	67.26	9,960
2012	748,942.22	67,307	91,855	657,087	68.26	9,626
2013	116,407.20	8,909	12,158	104,249	69.26	1,505
2014	488,601.92	30,880	42,142	446,460	70.26	6,354
2015	93,957.05	4,698	6,411	87,546	71.25	1,229
2016	479,282.50	17,575	23,985	455,298	72.25	6,302
2017	188,563.67	4,399	6,004	182,560	73.25	2,492
2018	1,113,412.34	11,134	15,195	1,098,217	74.25	14,791
2019	408,158.60	653	891	407,268	74.88	5,439
	116,213,888.14	42,439,137	57,724,371	58,489,517		1,166,637

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 50.1   1.00

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0.5						
1944	2,235.78	1,976	2,236			
1945	336.40	295	336			
1947	724.48	624	724			
1948	1,118.77	955	1,119			
1949	12,922.18	10,938	12,922			
1950	8,418.08	7,062	8,418			
1951	25,130.19	20,891	25,130			
1952	15,540.16	12,798	15,540			
1953	29,684.09	24,222	29,684			
1954	64,800.97	52,373	64,801			
1955	76,255.87	61,038	76,256			
1956	72,039.79	57,087	72,040			
1957	335,036.82	262,893	335,037			
1958	199,807.50	155,184	199,808			
1959	351,311.91	270,043	351,312			
1960	1,961.01	1,491	1,961			
1961	272,737.88	205,219	272,738			
1962	185,569.80	138,105	185,570			
1963	203,233.33	149,535	203,233			
1964	233,805.04	170,053	233,805			
1965	205,917.49	148,032	205,917			
1966	327,958.59	232,995	327,959			
1967	677,179.13	475,231	677,179			
1968	1,039,858.85	720,508	1,039,859			
1969	50,731.83	34,712	50,732			
1970	329,094.38	222,175	329,094			
1971	1,182,405.29	787,742	1,181,504	901	15.02	60
1972	426,002.68	279,837	419,717	6,286	15.44	407
1973	1,506,602.76	975,947	1,463,785	42,818	15.85	2,701
1974	1,333,301.85	850,940	1,276,292	57,010	16.28	3,502
1975	802,773.92	504,856	757,214	45,560	16.70	2,728
1976	1,185,249.48	733,800	1,100,598	84,651	17.14	4,939
1977	1,292,925.07	787,818	1,181,618	111,307	17.58	6,331
1978	2,132,194.10	1,278,378	1,917,390	214,804	18.02	11,920
1979	2,105,744.42	1,241,463	1,862,022	243,722	18.47	13,196
1980	2,024,053.53	1,172,595	1,758,730	265,324	18.93	14,016
1981	2,239,915.11	1,274,265	1,911,221	328,694	19.40	16,943
1982	2,223,339.83	1,241,602	1,862,231	361,109	19.87	18,174
1983	1,883,225.14	1,031,593	1,547,246	335,979	20.35	16,510
1984	2,158,943.22	1,159,115	1,738,512	420,431	20.84	20,174
1985	5,763,308.81	3,031,500	4,546,829	1,216,480	21.33	57,031
1986	4,947,513.81	2,547,425	3,820,784	1,126,730	21.83	51,614
1987	5,916,441.76	2,977,923	4,466,471	1,449,971	22.35	64,876
1988	10,628,523.75	5,226,895	7,839,617	2,788,907	22.87	121,946

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0.5						
1989	9,602,801.82	4,611,457	6,916,545	2,686,257	23.39	114,846
1990	8,468,262.17	3,965,010	5,946,965	2,521,297	23.93	105,361
1991	15,171,652.62	6,918,274	10,376,451	4,795,202	24.48	195,882
1992	11,899,447.87	5,278,119	7,916,446	3,983,002	25.04	159,066
1993	12,223,518.31	5,269,681	7,903,790	4,319,728	25.60	168,739
1994	7,150,242.62	2,990,374	4,485,146	2,665,097	26.18	101,799
1995	7,920,816.11	3,208,802	4,812,758	3,108,058	26.77	116,102
1996	9,892,822.90	3,875,810	5,813,177	4,079,646	27.37	149,055
1997	12,104,593.29	4,578,199	6,866,663	5,237,930	27.98	187,203
1998	17,035,729.39	6,204,753	9,306,268	7,729,461	28.61	270,166
1999	12,614,820.80	4,417,963	6,626,331	5,988,490	29.24	204,805
2000	11,661,081.97	3,915,558	5,872,794	5,788,288	29.89	193,653
2001	11,730,578.16	3,766,806	5,649,686	6,080,892	30.55	199,047
2002	9,277,691.70	2,838,974	4,258,067	5,019,625	31.23	160,731
2003	10,256,649.80	2,981,300	4,471,536	5,785,114	31.92	181,238
2004	10,528,736.18	2,896,561	4,344,439	6,184,297	32.62	189,586
2005	19,613,782.22	5,082,127	7,622,485	11,991,297	33.34	359,667
2006	19,307,206.12	4,685,280	7,027,270	12,279,936	34.08	360,327
2007	7,280,720.39	1,645,443	2,467,936	4,812,784	34.83	138,179
2008	23,809,940.01	4,978,897	7,467,655	16,342,285	35.59	459,182
2009	20,469,019.88	3,921,045	5,881,023	14,587,997	36.38	400,989
2010	17,115,332.26	2,974,302	4,461,040	12,654,292	37.18	340,352
2011	16,292,312.56	2,538,016	3,806,672	12,485,641	37.99	328,656
2012	47,712,777.27	6,541,899	9,811,941	37,900,836	38.83	976,071
2013	23,512,584.72	2,779,658	4,169,101	19,343,484	39.68	487,487
2014	31,328,330.00	3,091,166	4,636,320	26,692,010	40.56	658,087
2015	35,679,284.24	2,814,739	4,221,718	31,457,566	41.45	758,928
2016	33,182,808.42	1,939,203	2,908,535	30,274,273	42.37	714,521
2017	28,312,782.73	1,069,657	1,604,337	26,708,446	43.30	616,823
2018	28,417,293.99	467,180	700,705	27,716,589	44.26	626,222
2019	4,987,704.11	13,317	19,974	4,967,730	44.88	110,689
	589,037,199.48	142,799,699	213,748,965	375,288,234		10,460,527

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.9 1.78

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-R1						
1943	446.55	437	447			
1944	181.79	176	182			
1946	27.81	26	28			
1959	83,924.08	71,206	83,924			
1961	144,452.25	120,044	144,452			
1962	145,356.23	119,490	143,859	1,497	6.94	216
1963	175,684.37	142,800	171,923	3,761	7.30	515
1964	191,749.96	154,088	185,513	6,237	7.66	814
1965	241,498.69	191,774	230,885	10,614	8.03	1,322
1966	271,091.31	212,633	255,998	15,093	8.41	1,795
1967	821,032.17	635,988	765,693	55,339	8.79	6,296
1968	1,884,372.91	1,440,829	1,734,675	149,698	9.18	16,307
1969	2,807,106.12	2,118,298	2,550,308	256,798	9.57	26,834
1970	1,920,801.21	1,429,268	1,720,756	200,045	9.98	20,045
1971	2,642,702.29	1,938,660	2,334,034	308,668	10.39	29,708
1972	2,807,889.49	2,029,599	2,443,520	364,369	10.81	33,707
1973	5,556,897.66	3,956,789	4,763,745	793,153	11.23	70,628
1974	7,272,810.73	5,096,568	6,135,972	1,136,839	11.67	97,416
1975	824,348.48	568,380	684,297	140,051	12.11	11,565
1976	3,682,166.05	2,496,324	3,005,429	676,737	12.56	53,880
1977	3,574,413.40	2,381,095	2,866,700	707,713	13.02	54,356
1978	3,674,216.14	2,403,305	2,893,440	780,776	13.49	57,878
1979	2,961,417.50	1,901,378	2,289,149	672,268	13.96	48,157
1980	1,267,960.90	798,486	961,331	306,630	14.44	21,235
1981	2,566,976.18	1,583,619	1,906,585	660,391	14.94	44,203
1982	3,843,380.56	2,321,786	2,795,296	1,048,085	15.44	67,881
1983	5,889,952.15	3,481,138	4,191,088	1,698,864	15.95	106,512
1984	8,196,918.58	4,735,278	5,701,000	2,495,919	16.47	151,543
1985	10,646,224.29	6,005,535	7,230,316	3,415,908	17.00	200,936
1986	13,418,818.36	7,387,194	8,893,753	4,525,065	17.53	258,133
1987	13,085,034.51	7,018,943	8,450,400	4,634,635	18.08	256,340
1988	13,346,933.30	6,971,237	8,392,965	4,953,968	18.63	265,913
1989	14,739,050.72	7,482,869	9,008,941	5,730,110	19.20	298,443
1990	10,818,885.33	5,334,576	6,422,520	4,396,365	19.77	222,376
1991	8,488,276.62	4,059,179	4,887,016	3,601,261	20.35	176,966
1992	7,920,139.41	3,667,658	4,415,648	3,504,491	20.94	167,359
1993	10,905,033.79	4,882,075	5,877,735	5,027,299	21.54	233,394
1994	12,236,378.93	5,286,728	6,364,914	5,871,465	22.15	265,077
1995	11,270,159.48	4,693,007	5,650,108	5,620,051	22.76	246,927
1996	9,706,026.95	3,887,361	4,680,157	5,025,870	23.38	214,964
1997	10,131,723.87	3,894,229	4,688,426	5,443,298	24.01	226,710
1998	7,398,849.35	2,722,407	3,277,620	4,121,229	24.65	167,190
1999	8,137,321.77	2,860,594	3,443,989	4,693,333	25.29	185,581
2000	18,190,043.34	6,091,300	7,333,572	10,856,471	25.94	418,522

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-R1						
2001	20,090,061.30	6,387,635	7,690,342	12,399,719	26.60	466,155
2002	19,639,566.11	5,912,099	7,117,825	12,521,741	27.26	459,345
2003	29,372,196.22	8,344,641	10,046,464	19,325,732	27.92	692,182
2004	43,157,570.04	11,508,829	13,855,963	29,301,607	28.60	1,024,532
2005	50,602,730.13	12,624,875	15,199,618	35,403,112	29.27	1,209,536
2006	33,002,554.96	7,658,243	9,220,081	23,782,474	29.95	794,073
2007	19,754,783.24	4,239,772	5,104,440	14,650,343	30.63	478,300
2008	46,954,439.10	9,246,268	11,131,971	35,822,468	31.32	1,143,757
2009	31,103,150.23	5,574,618	6,711,517	24,391,633	32.01	762,000
2010	31,331,078.29	5,053,076	6,083,611	25,247,467	32.71	771,858
2011	23,778,578.58	3,408,184	4,103,256	19,675,323	33.41	588,905
2012	85,907,301.81	10,771,058	12,967,729	72,939,573	34.11	2,138,363
2013	22,663,832.06	2,429,110	2,924,508	19,739,324	34.82	566,896
2014	23,024,480.35	2,048,488	2,466,261	20,558,219	35.53	578,616
2015	24,498,172.89	1,727,366	2,079,648	22,418,525	36.25	618,442
2016	24,878,862.67	1,288,476	1,551,251	23,327,612	36.98	630,817
2017	22,769,556.99	753,217	906,829	21,862,728	37.71	579,759
2018	27,487,978.38	394,727	475,229	27,012,749	38.44	702,725
2019	4,112,045.53	9,499	11,436	4,100,610	38.91	105,387
	828,017,614.46	223,954,535	269,626,288	558,391,326		19,039,292

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.3 2.30

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
1943	69,177.43	59,078	66,100	3,077	8.76	351
1944	3,807.57	3,234	3,618	190	9.04	21
1945	7,188.15	6,072	6,794	394	9.32	42
1946	18,019.94	15,134	16,933	1,087	9.61	113
1947	35,459.00	29,608	33,127	2,332	9.90	236
1948	50,731.96	42,099	47,103	3,629	10.21	355
1949	59,267.36	48,866	54,674	4,593	10.53	436
1950	67,997.56	55,678	62,296	5,702	10.87	525
1951	87,223.31	70,927	79,357	7,866	11.21	702
1952	106,307.95	85,809	96,008	10,300	11.57	890
1953	128,778.94	103,152	115,412	13,367	11.94	1,120
1954	202,303.65	160,765	179,873	22,431	12.32	1,821
1955	267,160.10	210,522	235,543	31,617	12.72	2,486
1956	314,022.50	245,305	274,461	39,562	13.13	3,013
1957	380,038.24	294,150	329,111	50,927	13.56	3,756
1958	421,884.24	323,446	361,889	59,995	14.00	4,285
1959	489,240.93	371,417	415,561	73,680	14.45	5,099
1960	601,258.10	451,743	505,435	95,823	14.92	6,422
1961	637,017.44	473,412	529,679	107,338	15.41	6,965
1962	774,039.89	568,788	636,391	137,649	15.91	8,652
1963	880,234.91	639,341	715,329	164,906	16.42	10,043
1964	1,022,307.80	733,506	820,686	201,622	16.95	11,895
1965	1,176,972.96	833,885	932,996	243,977	17.49	13,950
1966	1,429,624.20	999,779	1,118,607	311,017	18.04	17,240
1967	1,771,422.66	1,221,980	1,367,217	404,206	18.61	21,720
1968	1,958,041.21	1,331,801	1,490,091	467,950	19.19	24,385
1969	2,245,277.15	1,505,077	1,683,962	561,315	19.78	28,378
1970	2,285,199.03	1,508,620	1,687,926	597,273	20.39	29,292
1971	2,670,676.42	1,735,486	1,941,756	728,920	21.01	34,694
1972	3,366,126.01	2,152,638	2,408,488	957,638	21.63	44,274
1973	4,143,209.31	2,604,711	2,914,292	1,228,917	22.28	55,158
1974	3,871,055.22	2,391,654	2,675,912	1,195,143	22.93	52,121
1975	3,708,861.03	2,250,648	2,518,147	1,190,714	23.59	50,475
1976	4,150,859.61	2,472,543	2,766,415	1,384,445	24.26	57,067
1977	4,364,146.84	2,550,102	2,853,192	1,510,955	24.94	60,584
1978	4,973,279.42	2,848,844	3,187,441	1,785,838	25.63	69,678
1979	5,249,616.79	2,945,035	3,295,065	1,954,552	26.34	74,205
1980	4,972,244.27	2,730,607	3,055,151	1,917,093	27.05	70,872
1981	5,167,341.64	2,775,741	3,105,649	2,061,693	27.77	74,242
1982	5,438,489.82	2,855,207	3,194,560	2,243,930	28.50	78,734
1983	8,298,064.25	4,255,496	4,761,279	3,536,785	29.23	120,998
1984	10,997,329.33	5,502,294	6,156,265	4,841,064	29.98	161,476
1985	11,502,877.96	5,611,449	6,278,393	5,224,485	30.73	170,013
1986	12,423,766.09	5,901,289	6,602,682	5,821,084	31.50	184,796

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
1987	15,262,898.68	7,054,054	7,892,458	7,370,441	32.27	228,399
1988	12,612,004.35	5,666,952	6,340,493	6,271,511	33.04	189,816
1989	12,348,739.86	5,386,150	6,026,316	6,322,424	33.83	186,888
1990	9,526,721.16	4,029,803	4,508,762	5,017,959	34.62	144,944
1991	11,111,218.21	4,551,933	5,092,949	6,018,269	35.42	169,912
1992	14,395,576.83	5,703,096	6,380,933	8,014,644	36.23	221,216
1993	18,819,689.16	7,198,531	8,054,106	10,765,583	37.05	290,569
1994	14,348,551.73	5,292,176	5,921,173	8,427,379	37.87	222,534
1995	14,614,704.33	5,188,220	5,804,862	8,809,842	38.70	227,644
1996	14,518,851.55	4,953,397	5,542,129	8,976,723	39.53	227,086
1997	23,129,251.48	7,563,265	8,462,190	14,667,061	40.38	363,226
1998	24,326,739.93	7,610,134	8,514,630	15,812,110	41.23	383,510
1999	21,544,080.89	6,434,571	7,199,347	14,344,734	42.08	340,892
2000	16,849,796.15	4,790,903	5,360,322	11,489,474	42.94	267,570
2001	17,949,537.17	4,843,324	5,418,973	12,530,564	43.81	286,021
2002	16,162,630.10	4,126,804	4,617,292	11,545,338	44.68	258,401
2003	7,180,606.84	1,728,157	1,933,556	5,247,051	45.56	115,168
2004	584,724.91	132,148	147,854	436,871	46.44	9,407
2005	2,885,121.51	609,251	681,663	2,203,459	47.33	46,555
2006	2,474,803.11	485,482	543,184	1,931,619	48.23	40,050
2007	2,982,683.37	540,373	604,598	2,378,085	49.13	48,404
2008	6,007,310.54	998,235	1,116,879	4,890,432	50.03	97,750
2009	4,084,431.00	616,749	690,052	3,394,379	50.94	66,635
2010	6,002,239.82	815,284	912,184	5,090,056	51.85	98,169
2011	5,825,573.46	701,982	785,415	5,040,158	52.77	95,512
2012	14,749,829.27	1,551,240	1,735,612	13,014,217	53.69	242,396
2013	4,282,726.61	384,717	430,442	3,852,285	54.61	70,542
2014	6,849,224.21	509,103	569,612	6,279,612	55.54	113,065
2015	6,039,025.45	355,276	397,502	5,641,523	56.47	99,903
2016	7,206,909.07	311,122	348,100	6,858,809	57.41	119,471
2017	6,548,797.70	180,092	201,497	6,347,301	58.35	108,780
2018	8,051,616.91	95,251	106,572	7,945,045	59.29	134,003
2019	1,481,251.84	2,963	3,315	1,477,937	59.88	24,682
	463,545,815.39	164,387,676	183,925,838	279,619,977		7,102,700

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.4 1.53

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 23-L0.5						
1956	137.18	109	82	55	4.70	12
1957	10.79	9	7	4	4.80	1
1958	11.57	9	7	5	4.90	1
1959	26.83	21	16	11	5.01	2
1960	545.66	424	317	229	5.11	45
1961	387.88	300	225	163	5.21	31
1962	854.55	657	492	363	5.32	68
1963	1,685.58	1,288	964	722	5.43	133
1964	1,782.51	1,353	1,013	770	5.54	139
1965	2,345.06	1,768	1,324	1,021	5.66	180
1966	5,634.55	4,219	3,159	2,476	5.78	428
1967	4,075.11	3,028	2,267	1,808	5.91	306
1968	7,311.79	5,392	4,038	3,274	6.04	542
1969	13,710.89	10,027	7,508	6,203	6.18	1,004
1970	27,624.53	20,034	15,001	12,624	6.32	1,997
1971	37,654.42	27,062	20,264	17,390	6.47	2,688
1972	51,424.65	36,623	27,423	24,002	6.62	3,626
1973	58,238.17	41,071	30,754	27,484	6.78	4,054
1974	63,570.62	44,361	33,218	30,353	6.95	4,367
1975	44,681.41	30,849	23,100	21,581	7.12	3,031
1976	69,034.22	47,123	35,286	33,748	7.30	4,623
1977	103,999.88	70,177	52,549	51,451	7.48	6,878
1978	113,529.11	75,669	56,661	56,868	7.67	7,414
1979	158,598.14	104,399	78,174	80,424	7.86	10,232
1980	144,004.58	93,541	70,044	73,961	8.06	9,176
1981	161,435.59	103,388	77,417	84,019	8.27	10,159
1982	389,706.40	246,022	184,222	205,484	8.48	24,232
1983	869,065.75	540,707	404,882	464,184	8.69	53,416
1984	668,929.09	409,498	306,633	362,296	8.92	40,616
1985	758,366.22	456,999	342,202	416,164	9.14	45,532
1986	1,128,869.27	668,483	500,561	628,308	9.38	66,984
1987	840,417.45	488,904	366,092	474,325	9.62	49,306
1988	950,475.80	543,007	406,605	543,871	9.86	55,159
1989	929,386.40	520,856	390,018	539,368	10.11	53,350
1990	767,135.93	421,257	315,438	451,698	10.37	43,558
1991	1,058,148.48	569,104	426,146	632,002	10.63	59,455
1992	1,166,779.85	613,318	459,254	707,526	10.91	64,851
1993	1,211,141.15	622,418	466,068	745,073	11.18	66,643
1994	1,824,551.05	914,647	684,889	1,139,662	11.47	99,360
1995	1,586,632.70	775,387	580,611	1,006,022	11.76	85,546
1996	1,098,172.67	522,829	391,495	706,678	12.05	58,645
1997	1,606,024.57	742,963	556,332	1,049,693	12.36	84,927
1998	2,011,668.50	903,501	676,543	1,335,126	12.67	105,377
1999	1,580,755.81	687,977	515,159	1,065,597	12.99	82,032

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 23-L0.5						
2000	1,829,336.56	769,913	576,512	1,252,825	13.32	94,056
2001	2,504,842.54	1,018,269	762,482	1,742,361	13.65	127,645
2002	2,374,867.12	929,286	695,851	1,679,016	14.00	119,930
2003	3,993,522.28	1,501,924	1,124,644	2,868,878	14.35	199,922
2004	4,149,083.26	1,495,454	1,119,799	3,029,284	14.71	205,934
2005	3,763,906.88	1,296,101	970,523	2,793,384	15.08	185,238
2006	2,999,282.03	983,255	736,263	2,263,019	15.46	146,379
2007	1,273,904.50	395,458	296,120	977,784	15.86	61,651
2008	5,540,292.04	1,621,145	1,213,916	4,326,376	16.27	265,911
2009	6,235,290.16	1,702,484	1,274,823	4,960,467	16.72	296,679
2010	6,793,380.67	1,716,076	1,285,001	5,508,380	17.19	320,441
2011	4,792,532.01	1,106,452	828,513	3,964,019	17.69	224,082
2012	2,530,275.80	523,666	392,122	2,138,154	18.24	117,223
2013	14,384,576.12	2,614,253	1,957,558	12,427,018	18.82	660,309
2014	10,384,791.42	1,611,927	1,207,014	9,177,777	19.43	472,351
2015	19,845,469.68	2,510,849	1,880,129	17,965,341	20.09	894,243
2016	18,995,171.39	1,825,246	1,366,748	17,628,423	20.79	847,928
2017	10,753,143.08	682,610	511,139	10,242,004	21.54	475,488
2018	19,087,175.10	547,802	410,195	18,676,980	22.34	836,033
2019	3,054,357.67	14,600	10,933	3,043,425	22.89	132,959
	166,803,742.67	36,237,548	27,134,745	139,668,998		7,894,528

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.7   4.73

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-R2						
1943	82.36	82	82			
1954	19.90	20	20			
1960	44.51	45	45			
1961	22.06	22	22			
1963	3,560.09	3,560	3,560			
1964	4,198.55	4,199	4,199			
1965	4,504.15	4,504	4,504			
1966	4,064.24	4,064	4,064			
1967	1,796.52	1,792	1,153	644	0.07	644
1968	4,221.35	4,173	2,685	1,536	0.32	1,536
1969	1,190.48	1,166	750	440	0.58	440
1970	2,304.72	2,236	1,439	866	0.84	866
1972	947.92	901	580	368	1.39	265
1973	3,340.45	3,141	2,021	1,319	1.67	790
1974	327.60	305	196	132	1.96	67
1975	1,577.66	1,451	934	644	2.25	286
1977	818.52	736	474	345	2.83	122
1978	590.31	525	338	252	3.12	81
1979	937.94	824	530	408	3.41	120
1980	405.08	351	226	179	3.71	48
1981	7,063.15	6,049	3,892	3,171	4.02	789
1982	15,194.80	12,845	8,266	6,929	4.33	1,600
1983	11,814.80	9,848	6,337	5,478	4.66	1,176
1984	21,846.87	17,946	11,548	10,299	5.00	2,060
1985	12,985.63	10,504	6,759	6,227	5.35	1,164
1986	25,711.46	20,459	13,165	12,546	5.72	2,193
1987	23,264.32	18,188	11,704	11,560	6.11	1,892
1988	8,554.49	6,562	4,223	4,331	6.52	664
1989	108,179.86	81,329	52,334	55,846	6.95	8,035
1990	133,004.84	97,901	62,998	70,007	7.39	9,473
1991	63,220.53	45,451	29,247	33,974	7.87	4,317
1992	493,865.14	346,412	222,912	270,953	8.36	32,411
1993	925,202.27	632,107	406,754	518,448	8.87	58,450
1994	1,997,855.80	1,327,156	854,010	1,143,846	9.40	121,686
1995	2,934,135.27	1,890,434	1,216,473	1,717,662	9.96	172,456
1996	3,447,770.05	2,151,167	1,384,252	2,063,518	10.53	195,966
1997	1,163,566.83	701,049	451,117	712,450	11.13	64,012
1998	1,338,418.12	776,764	499,839	838,579	11.75	71,368
1999	155,667.79	86,841	55,881	99,787	12.38	8,060
2000	130,818.63	69,941	45,006	85,813	13.03	6,586
2001	197,865.84	101,052	65,026	132,840	13.70	9,696
2002	168,493.07	81,899	52,701	115,792	14.39	8,047
2003	338,606.26	155,999	100,384	238,222	15.10	15,776
2004	918,887.00	399,716	257,213	661,674	15.82	41,825

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-R2						
2005	1,022,285.61	418,043	269,006	753,280	16.55	45,515
2006	956,676.73	365,584	235,249	721,428	17.30	41,701
2007	463,448.15	164,357	105,762	357,686	18.07	19,794
2008	1,104,364.09	360,895	232,232	872,132	18.85	46,267
2009	1,116,354.32	333,310	214,482	901,872	19.64	45,920
2010	874,544.48	235,812	151,743	722,801	20.45	35,345
2011	610,115.06	146,647	94,366	515,749	21.27	24,248
2012	962,420.23	202,792	130,494	831,926	22.10	37,644
2013	640,816.17	115,802	74,517	566,299	22.94	24,686
2014	501,415.11	75,212	48,398	453,017	23.80	19,034
2015	614,134.32	73,260	47,142	566,992	24.66	22,992
2016	681,204.66	59,851	38,514	642,691	25.54	25,164
2017	651,778.05	36,545	23,516	628,262	26.43	23,771
2018	598,579.06	14,539	9,356	589,223	27.32	21,567
2019	148,364.01	583	375	147,989	27.89	5,306
	25,623,447.28	11,684,948	7,525,015	18,098,432		1,283,921

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.1   5.01

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-R1.5						
1943	89,248.66	89,249	89,249			
1944	883.69	884	884			
1945	4,861.40	4,861	4,861			
1946	1,638.48	1,638	1,638			
1947	940.18	940	940			
1948	2,193.87	2,194	2,194			
1949	7,147.43	7,147	7,147			
1950	4,298.09	4,298	4,298			
1951	11,057.96	11,058	11,058			
1952	5,414.14	5,414	5,414			
1953	17,482.79	17,483	17,483			
1954	17,621.96	17,622	17,622			
1955	24,039.06	24,039	24,039			
1956	42,827.02	42,827	42,827			
1957	68,064.42	68,064	68,064			
1958	40,449.29	40,449	40,449			
1959	69,524.40	69,524	69,524			
1960	42,176.22	42,176	42,176			
1961	20,647.66	20,648	20,648			
1962	28,372.95	28,373	28,373			
1963	62,254.94	61,810	62,255			
1964	63,585.62	62,450	63,586			
1965	41,487.37	40,243	41,487			
1966	36,874.01	35,333	36,874			
1967	59,912.23	56,681	59,912			
1968	115,796.85	108,352	115,797			
1969	86,074.82	79,742	86,075			
1970	119,840.94	110,039	119,841			
1971	94,914.01	86,406	94,914			
1972	167,076.91	150,727	167,077			
1973	169,386.15	151,358	169,386			
1974	80,260.76	71,002	80,261			
1975	224,312.85	196,354	223,141	1,172	3.49	336
1976	24,461.92	21,177	24,066	396	3.76	105
1977	61,529.74	52,652	59,835	1,695	4.04	420
1979	142,118.78	118,618	134,800	7,319	4.63	1,581
1980	125,732.41	103,595	117,728	8,004	4.93	1,624
1981	296,818.17	241,272	274,187	22,631	5.24	4,319
1982	459,243.24	368,051	418,262	40,981	5.56	7,371
1983	563,385.24	444,674	505,338	58,047	5.90	9,838
1984	634,460.18	493,064	560,329	74,131	6.24	11,880
1985	1,315,355.04	1,005,313	1,142,461	172,894	6.60	26,196
1986	2,650,354.05	1,989,647	2,261,080	389,274	6.98	55,770
1987	2,691,062.88	1,982,748	2,253,240	437,823	7.37	59,406

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 28-R1.5						
1988	3,109,552.57	2,245,532	2,551,874	557,679	7.78	71,681
1989	2,370,522.84	1,675,462	1,904,033	466,490	8.21	56,820
1990	1,850,525.16	1,278,842	1,453,305	397,220	8.65	45,921
1991	1,954,780.31	1,318,089	1,497,907	456,873	9.12	50,096
1992	2,266,201.24	1,489,211	1,692,374	573,827	9.60	59,774
1993	3,174,864.27	2,029,659	2,306,551	868,313	10.10	85,972
1994	2,620,734.43	1,625,799	1,847,595	773,139	10.63	72,732
1995	2,616,109.11	1,572,465	1,786,985	829,124	11.17	74,228
1996	3,194,826.37	1,857,568	2,110,983	1,083,843	11.72	92,478
1997	3,974,218.37	2,228,384	2,532,387	1,441,831	12.30	117,222
1998	2,807,679.14	1,515,136	1,721,835	1,085,844	12.89	84,239
1999	6,713,391.94	3,476,597	3,950,885	2,762,507	13.50	204,630
2000	5,353,467.49	2,653,767	3,015,802	2,337,665	14.12	165,557
2001	12,094,384.23	5,718,951	6,499,147	5,595,237	14.76	379,081
2002	3,887,671.14	1,746,692	1,984,981	1,902,690	15.42	123,391
2003	4,237,776.29	1,804,064	2,050,180	2,187,596	16.08	136,045
2004	6,072,480.08	2,435,490	2,767,747	3,304,733	16.77	197,062
2005	9,233,535.75	3,475,780	3,949,956	5,283,580	17.46	302,611
2006	8,206,360.75	2,881,007	3,274,042	4,932,319	18.17	271,454
2007	6,442,901.26	2,098,517	2,384,803	4,058,098	18.88	214,942
2008	8,489,173.54	2,543,696	2,890,714	5,598,460	19.61	285,490
2009	8,481,996.58	2,317,366	2,633,508	5,848,489	20.35	287,395
2010	9,471,612.10	2,334,089	2,652,512	6,819,100	21.10	323,180
2011	8,253,256.26	1,812,745	2,060,045	6,193,211	21.85	283,442
2012	17,491,942.11	3,360,902	3,819,406	13,672,536	22.62	604,445
2013	9,568,163.44	1,575,302	1,790,209	7,777,954	23.39	332,533
2014	10,224,857.50	1,398,658	1,589,467	8,635,390	24.17	357,277
2015	11,437,865.98	1,241,809	1,411,220	10,026,646	24.96	401,709
2016	11,150,627.87	892,050	1,013,746	10,136,882	25.76	393,512
2017	10,581,892.12	540,417	614,142	9,967,750	26.57	375,151
2018	12,038,543.94	266,533	302,894	11,735,650	27.38	428,621
2019	2,750,844.95	9,821	11,161	2,739,684	27.90	98,197
	222,907,947.91	71,950,596	81,643,216	141,264,732		7,155,734

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.7   3.21

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.30 STREET LIGHTING AND SIGNAL SYSTEMS - LED

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R0.5						
2016	2,001.82	113	60	1,942	28.30	69
2017	55,148.26	1,985	1,048	54,100	28.92	1,871
2018	223,423.50	3,501	1,848	221,576	29.53	7,503
2019	75,479.08	202	107	75,372	29.92	2,519
	356,052.66	5,801	3,063	352,990		11,962

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.5 3.36

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 389.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R3						
1962	381.16	325	189	192	7.34	26
1975	86.47	63	37	49	13.39	4
1978	12,434.03	8,647	5,025	7,409	15.23	486
2008	4.59	1	1	4	39.60	
	12,906.25	9,036	5,252	7,654		516

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.8   4.00

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
1896	20,624.89	20,625	20,625			
1901	2,407.12	2,407	2,407			
1902	19,555.22	19,555	19,555			
1907	9,177.86	9,178	9,178			
1908	5,957.29	5,957	5,957			
1909	25.84	26	26			
1911	5,643.55	5,644	5,644			
1912	5,046.37	5,046	5,046			
1913	1,583.37	1,583	1,583			
1914	6,063.45	6,063	6,063			
1915	1,194.72	1,195	1,195			
1916	17.05	17	17			
1920	2,766.92	2,735	2,767			
1921	514.62	505	515			
1922	5,094.19	4,968	5,094			
1923	2,506.25	2,428	2,506			
1924	3,161.74	3,041	3,162			
1925	11,446.33	10,931	11,446			
1926	5,000.63	4,743	5,001			
1927	24.36	23	24			
1928	17,400.15	16,290	17,400			
1929	2,817.47	2,623	2,817			
1930	5,268.87	4,880	5,269			
1931	410.56	378	411			
1932	2,143.77	1,966	2,144			
1933	5,751.97	5,249	5,752			
1934	37.91	34	38			
1935	2,624.62	2,371	2,625			
1936	523.87	471	524			
1937	102.52	92	103			
1938	36,667.85	32,590	36,668			
1939	12,008.64	10,613	12,009			
1940	6,381.42	5,607	6,381			
1941	1,239.37	1,082	1,239			
1942	36.68	32	37			
1943	210.86	182	211			
1944	9.41	8	9			
1945	200.98	171	201			
1946	740.03	625	740			
1947	4,796.46	4,026	4,796			
1948	87.49	73	87			
1950	365.47	300	365			
1951	47,726.92	38,897	47,727			
1953	198,882.85	159,544	198,883			

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
1954	281,455.94	223,926	281,456			
1955	56,051.77	44,214	56,052			
1956	407,394.11	318,582	407,394			
1957	137,040.47	106,206	137,040			
1958	428,966.48	329,360	428,966			
1959	310,827.12	236,353	310,827			
1960	357,619.15	269,216	357,619			
1961	104,853.88	78,137	104,854			
1962	860,084.67	634,054	860,085			
1963	160,773.76	117,204	160,774			
1964	351,849.48	253,613	351,849			
1965	519,356.76	369,886	519,357			
1966	1,320,134.11	928,846	1,320,134			
1967	843,387.33	585,817	843,387			
1968	34,543.00	23,683	34,498	45	15.72	3
1969	162,964.47	110,197	160,519	2,445	16.19	151
1970	698,752.08	465,788	678,491	20,261	16.67	1,215
1971	15,175.13	9,967	14,518	657	17.16	38
1972	56,013.30	36,241	52,790	3,223	17.65	183
1973	131,636.29	83,826	122,105	9,531	18.16	525
1974	287,010.33	179,783	261,881	25,129	18.68	1,345
1975	8,662.16	5,334	7,770	892	19.21	46
1976	83,211.12	50,343	73,332	9,879	19.75	500
1977	72,566.36	43,104	62,787	9,779	20.30	482
1978	744,789.16	434,063	632,278	112,511	20.86	5,394
1979	1,757,817.47	1,004,417	1,463,085	294,732	21.43	13,753
1980	47,492.29	26,586	38,727	8,765	22.01	398
1981	1,125,627.32	616,844	898,526	227,101	22.60	10,049
1982	167,733.19	89,905	130,960	36,773	23.20	1,585
1983	2,853,120.90	1,494,465	2,176,914	676,207	23.81	28,400
1984	963,704.80	493,031	718,174	245,531	24.42	10,055
1985	1,393,329.76	695,272	1,012,769	380,561	25.05	15,192
1986	1,988,990.98	967,445	1,409,230	579,761	25.68	22,576
1987	2,707,231.35	1,282,145	1,867,638	839,593	26.32	31,899
1988	1,235,560.06	568,852	828,619	406,941	26.98	15,083
1989	1,049,724.17	469,647	684,112	365,612	27.63	13,232
1990	9,607,396.72	4,169,610	6,073,667	3,533,730	28.30	124,867
1991	3,055,455.73	1,285,125	1,871,979	1,183,477	28.97	40,852
1992	4,570,147.48	1,859,136	2,708,112	1,862,035	29.66	62,779
1993	1,892,399.37	744,091	1,083,881	808,518	30.34	26,649
1994	644,512.09	244,399	356,004	288,508	31.04	9,295
1995	1,693,555.24	618,486	900,918	792,637	31.74	24,973
1996	996,996.12	349,946	509,749	487,247	32.45	15,015
1997	1,051,596.93	353,968	515,608	535,989	33.17	16,159

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
1998	6,046,286.82	1,948,114	2,837,723	3,208,564	33.89	94,676
1999	3,065,193.00	942,853	1,373,408	1,691,785	34.62	48,867
2000	2,033,589.86	595,842	867,934	1,165,656	35.35	32,975
2001	1,495,217.39	415,969	605,922	889,295	36.09	24,641
2002	106,925.25	28,164	41,025	65,900	36.83	1,789
2003	1,523,675.05	378,481	551,315	972,360	37.58	25,874
2004	184,897.21	43,155	62,862	122,035	38.33	3,184
2005	581,242.68	126,827	184,743	396,500	39.09	10,143
2006	555,834.69	112,834	164,360	391,475	39.85	9,824
2007	671,088.43	125,896	183,386	487,702	40.62	12,006
2008	1,301,715.05	223,895	326,137	975,578	41.40	23,565
2009	1,120,042.52	175,399	255,495	864,548	42.17	20,501
2010	631,103.43	88,859	129,437	501,666	42.96	11,678
2011	323,393.07	40,489	58,978	264,415	43.74	6,045
2012	361,449.84	39,543	57,600	303,850	44.53	6,823
2013	439,511.38	41,050	59,796	379,715	45.33	8,377
2014	497,635.80	38,517	56,106	441,530	46.13	9,571
2015	2,401,028.21	146,943	214,044	2,186,984	46.94	46,591
2016	3,850,885.15	173,290	252,423	3,598,462	47.75	75,360
2017	11,123,904.34	320,368	466,664	10,657,240	48.56	219,465
2018	1,417,295.35	17,574	25,599	1,391,696	49.38	28,183
2019	21,541.05	43	63	21,478	49.90	430
	87,445,213.88	29,689,992	42,718,702	44,726,512		1,213,261

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.9 1.39

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
1911	644.21	644	644			
1918	1,465.85	1,455	1,466			
1919	441.10	438	441			
1922	359.78	353	360			
1923	2,421.65	2,368	2,422			
1924	1,391.56	1,355	1,392			
1925	301.85	293	302			
1928	37,676.87	36,069	37,677			
1929	6,688.96	6,376	6,689			
1930	1,028.45	976	1,028			
1932	650.71	612	651			
1935	31.26	29	31			
1938	3,180.25	2,908	3,180			
1939	36.74	33	37			
1940	26.40	24	26			
1941	1,566.41	1,412	1,566			
1943	265.10	237	265			
1945	914.89	808	915			
1947	372.04	325	372			
1948	74.38	65	74			
1950	63.96	55	64			
1951	5,581.73	4,751	5,582			
1953	23,597.44	19,798	23,597			
1954	36,079.14	30,036	36,079			
1955	11,814.02	9,756	11,814			
1956	62,896.83	51,502	62,897			
1957	20,309.68	16,481	20,310			
1958	34,611.38	27,828	34,611			
1959	97,990.75	78,033	97,991			
1960	51,964.17	40,965	51,964			
1961	46,226.60	36,057	46,227			
1962	163,723.68	126,285	163,724			
1963	35,780.72	27,289	35,781			
1964	133,910.63	100,902	133,911			
1965	102,664.70	76,400	102,665			
1966	316,888.68	232,809	316,889			
1967	133,079.92	96,460	133,080			
1968	65,295.76	46,665	65,296			
1969	74,967.67	52,802	74,968			
1970	127,111.70	88,194	127,112			
1971	24,200.99	16,533	24,201			
1972	45,546.46	30,615	45,546			
1973	30,612.56	20,235	30,613			
1974	110,464.42	71,765	110,464			

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
1975	1,156.81	738	1,157			
1976	13,857.82	8,680	13,858			
1977	50,155.74	30,812	50,156			
1978	142,642.63	85,918	142,643			
1979	171,247.53	101,036	171,248			
1980	74,397.92	42,965	74,398			
1981	242,458.26	136,989	242,458			
1982	317,970.15	175,574	317,970			
1983	1,161,067.84	626,199	1,161,068			
1984	336,816.01	177,222	331,652	5,164	28.43	182
1985	224,620.57	115,230	215,641	8,980	29.22	307
1986	452,633.20	226,090	423,104	29,529	30.03	983
1987	203,380.33	98,843	184,974	18,406	30.84	597
1988	802,680.58	379,130	709,502	93,179	31.66	2,943
1989	484,001.21	221,997	415,444	68,557	32.48	2,111
1990	959,025.68	426,450	798,057	160,969	33.32	4,831
1991	1,101,413.91	474,346	887,689	213,725	34.16	6,257
1992	188,166.33	78,339	146,603	41,563	35.02	1,187
1993	285,694.18	114,898	215,020	70,674	35.87	1,970
1994	351,417.43	136,234	254,948	96,469	36.74	2,626
1995	347,286.58	129,538	242,417	104,870	37.62	2,788
1996	62,739.34	22,481	42,071	20,668	38.50	537
1997	416,255.97	142,984	267,579	148,677	39.39	3,774
1998	363,029.11	119,317	223,289	139,740	40.28	3,469
1999	159,874.62	50,148	93,847	66,028	41.18	1,603
2000	313,524.37	93,587	175,138	138,386	42.09	3,288
2001	7,943.07	2,249	4,209	3,734	43.01	87
2002	134,992.14	36,155	67,660	67,332	43.93	1,533
2003	68,203.36	17,221	32,227	35,976	44.85	802
2006	49,286.73	10,137	18,970	30,317	47.66	636
2007	50,027.69	9,497	17,773	32,255	48.61	664
2008	629,960.13	109,613	205,129	424,831	49.56	8,572
2009	57,468.60	9,090	17,011	40,458	50.51	801
2010	67,964.51	9,663	18,083	49,882	51.47	969
2011	78,590.21	9,902	18,531	60,059	52.44	1,145
	12,186,872.61	5,788,268	10,016,448	2,170,425		54,662

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.7 0.45

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 391.10 OFFICE FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
1993	1,282,688.83	1,282,689	1,282,689			
	1,282,688.83	1,282,689	1,282,689			
AMORTIZED						
SURVIVOR CURVE.. 25-SQUARE						
1994	485,586.89	480,731	477,618	7,969	0.25	7,969
1995	625,360.04	594,092	590,245	35,115	1.25	28,092
1996	515,826.54	469,402	466,362	49,464	2.25	21,984
1997	401,918.53	349,669	347,405	54,514	3.25	16,774
1998	3,879,695.06	3,220,147	3,199,295	680,400	4.25	160,094
1999	375,883.86	296,948	295,025	80,859	5.25	15,402
2000	634,280.62	475,710	472,630	161,651	6.25	25,864
2001	261,459.11	185,636	184,434	77,025	7.25	10,624
2002	2,354.78	1,578	1,568	787	8.25	95
2003	2,020.08	1,273	1,265	755	9.25	82
2004	50,859.86	30,007	29,813	21,047	10.25	2,053
2007	115,216.50	54,152	53,801	61,415	13.25	4,635
2008	110,781.84	47,636	47,328	63,454	14.25	4,453
2009	67,138.21	26,184	26,014	41,124	15.25	2,697
2011	4,518.68	1,401	1,392	3,127	17.25	181
2013	19,433.42	4,470	4,441	14,992	19.25	779
2014	11,999.38	2,280	2,265	9,734	20.25	481
2015	1,843.03	276	274	1,569	21.25	74
2016	4,858.28	534	531	4,328	22.25	195
2017	1,162,755.22	81,393	80,866	1,081,889	23.25	46,533
2018	173,070.20	5,192	5,158	167,912	24.25	6,924
2019	14,654.82	70	70	14,585	24.88	586
	8,921,514.95	6,328,781	6,287,800	2,633,715		356,571
	10,204,203.78	7,611,470	7,570,489	2,633,715		356,571

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.4   3.49

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 391.15 OFFICE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
1998	2,506,944.10	2,506,944	2,506,944			
	2,506,944.10	2,506,944	2,506,944			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 391.20 PERSONAL COMPUTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
2011	6,538.08	6,538	6,538			
2013	2,678,236.27	2,678,236	2,678,236			
	2,684,774.35	2,684,774	2,684,774			
AMORTIZED						
SURVIVOR CURVE.. 5-SQUARE						
2014	2,322,948.29	2,206,801	2,001,464	321,484	0.25	321,484
2015	1,966,239.18	1,474,679	1,337,464	628,775	1.25	503,020
2016	743,164.37	408,740	370,708	372,456	2.25	165,536
2017	1,221,682.76	427,589	387,803	833,880	3.25	256,578
2018	1,241,905.09	186,286	168,953	1,072,952	4.25	252,459
2019	202,502.41	4,860	4,408	198,095	4.88	40,593
	7,698,442.10	4,708,955	4,270,800	3,427,642		1,539,670
	10,383,216.45	7,393,729	6,955,574	3,427,642		1,539,670

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.2 14.83

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 391.25 INFORMATION SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
2012	15,704.47	15,704	15,704			
	15,704.47	15,704	15,704			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 13-L2						
1963	2,410.94	2,411	2,411			
1964	861.90	862	862			
1967	2,419.58	2,420	2,420			
1968	7,161.66	7,162	7,162			
1969	24,777.28	24,777	24,777			
1971	2,744.82	2,745	2,745			
1976	34,215.84	34,216	34,216			
1977	8,287.76	8,288	8,288			
1978	4,329.56	4,330	4,330			
1979	24,812.09	24,812	24,812			
1980	3,489.49	3,489	3,489			
1982	2,015.34	2,015	2,015			
1983	1,602.43	1,569	1,602			
1985	77,685.91	74,161	77,686			
1987	185,036.04	171,656	185,036			
1988	125,948.20	115,098	125,948			
1990	28,855.89	25,571	28,856			
1991	245,291.10	213,781	245,291			
1992	48,743.23	41,732	48,743			
1993	108,519.39	91,240	108,519			
1994	163,179.93	134,685	163,180			
1995	36,490.53	29,529	36,491			
1997	108,484.65	84,117	108,485			
1998	698,784.08	529,462	692,179	6,605	3.15	2,097
1999	273,797.25	202,399	264,602	9,195	3.39	2,712
2001	22,742.23	15,937	20,835	1,907	3.89	490
2007	14,493.19	8,518	11,136	3,357	5.36	626
2009	507,319.73	275,906	360,699	146,621	5.93	24,725
2010	4,542.60	2,348	3,070	1,473	6.28	235
2011	8,690.49	4,198	5,488	3,202	6.72	476
2013	644,591.48	252,880	330,596	313,995	7.90	39,746
2015	24,739.08	6,699	8,758	15,981	9.48	1,686
2016	1,970.58	402	526	1,445	10.35	140
2017	1,168,980.92	154,668	202,201	966,780	11.28	85,707
2018	1,280,430.44	73,868	96,570	1,183,860	12.25	96,642
2019	281,490.36	2,598	3,396	278,094	12.88	21,591
	6,179,935.99	2,630,549	3,247,420	2,932,516		276,873

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.6 4.48

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 393.00 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
1988	30,113.41	30,113	30,113			
	30,113.41	30,113	30,113			
AMORTIZED SURVIVOR CURVE.. 30-SQUARE						
1989	241,318.07	239,308	235,801	5,517	0.25	5,517
1990	13,497.94	12,935	12,745	753	1.25	602
1991	118,575.53	109,682	108,074	10,501	2.25	4,667
1992	33,537.55	29,904	29,466	4,072	3.25	1,253
1993	93,905.14	80,602	79,421	14,484	4.25	3,408
1994	9,007.70	7,431	7,322	1,686	5.25	321
1995	109,761.75	86,895	85,621	24,140	6.25	3,862
1996	57,707.54	43,761	43,120	14,588	7.25	2,012
1997	176,740.33	128,137	126,259	50,481	8.25	6,119
1998	263,796.27	182,460	179,786	84,010	9.25	9,082
1999	302,653.31	199,246	196,326	106,328	10.25	10,373
2000	17,779.58	11,112	10,949	6,830	11.25	607
2001	59,452.83	35,176	34,660	24,792	12.25	2,024
	1,497,733.54	1,166,649	1,149,550	348,184		49,847
	1,527,846.95	1,196,762	1,179,663	348,184		49,847

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.0   3.26

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
1993	624,254.35	624,254	624,254			
	624,254.35	624,254	624,254			
AMORTIZED						
SURVIVOR CURVE.. 25-SQUARE						
1994	1,535,693.91	1,520,337	1,499,842	35,852	0.25	35,852
1995	817,292.36	776,428	765,961	51,331	1.25	41,065
1996	366,889.30	333,869	329,368	37,521	2.25	16,676
1997	476,399.29	414,467	408,880	67,520	3.25	20,775
1998	2,220,693.35	1,843,175	1,818,328	402,366	4.25	94,674
1999	372,779.88	294,496	290,526	82,254	5.25	15,667
2000	741,293.94	555,970	548,475	192,819	6.25	30,851
2001	882,724.73	626,735	618,286	264,439	7.25	36,474
2002	556,324.58	372,737	367,712	188,612	8.25	22,862
2003	168,357.46	106,065	104,635	63,722	9.25	6,889
2004	36,981.53	21,819	21,525	15,457	10.25	1,508
2005	163,311.16	89,821	88,610	74,701	11.25	6,640
2007	3,481,726.36	1,636,411	1,614,351	1,867,375	13.25	140,934
2008	551,672.48	237,219	234,021	317,651	14.25	22,291
2009	165,264.82	64,453	63,584	101,681	15.25	6,668
2010	252,656.05	88,430	87,238	165,418	16.25	10,180
2012	155,515.96	41,989	41,423	114,093	18.25	6,252
2013	1,135,974.22	261,274	257,752	878,222	19.25	45,622
2014	3,159,042.99	600,218	592,127	2,566,916	20.25	126,761
2016	40.76	4	4	37	22.25	2
2017	54,793.36	3,836	3,784	51,009	23.25	2,194
2018	2,043,561.71	61,307	60,481	1,983,081	24.25	81,777
2019	166,243.81	798	787	165,457	24.88	6,650
	19,505,234.01	9,951,858	9,817,700	9,687,534		779,264
	20,129,488.36	10,576,112	10,441,954	9,687,534		779,264

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.4   3.87

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 395.00 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
1998	73,468.10	73,468	73,468			
	73,468.10	73,468	73,468			
AMORTIZED SURVIVOR CURVE.. 20-SQUARE						
2000	1,699.29	1,593	1,593	106	1.25	85
2001	20,936.69	18,581	18,582	2,355	2.25	1,047
2003	139,165.86	109,593	109,599	29,567	4.25	6,957
2007	94,314.00	55,409	55,412	38,902	8.25	4,715
2008	195,086.10	104,859	104,864	90,222	9.25	9,754
	451,201.94	290,035	290,050	161,152		22,558
	524,670.04	363,503	363,518	161,152		22,558

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.1   4.30

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-S1						
1957	495.89	496	496			
1965	24,854.78	24,855	24,855			
1969	44,987.30	44,987	44,987			
1972	2,191.85	2,192	2,192			
1976	33,742.58	33,743	33,743			
1985	20,714.87	18,944	20,715			
1987	3,812.32	3,374	3,812			
1991	346,788.59	285,060	338,104	8,685	3.56	2,440
1992	71,473.31	57,536	68,242	3,231	3.90	828
1993	117,137.99	92,305	109,481	7,657	4.24	1,806
1994	107,459.31	82,797	98,204	9,255	4.59	2,016
1995	144,563.84	108,784	129,027	15,537	4.95	3,139
1998	703,828.32	488,809	579,767	124,061	6.11	20,305
2000	1,310,310.64	854,978	1,014,073	296,238	6.95	42,624
2001	106,284.56	66,959	79,419	26,866	7.40	3,631
2008	17,931.41	7,962	9,444	8,487	11.12	763
2009	103,923.59	42,817	50,784	53,140	11.76	4,519
2012	59,670.73	18,200	21,587	38,084	13.90	2,740
2013	28,026.85	7,427	8,809	19,218	14.70	1,307
2015	428,055.83	77,050	91,387	336,669	16.40	20,529
2017	166,682.37	14,418	17,101	149,581	18.27	8,187
2018	424,711.43	15,927	18,890	405,821	19.25	21,082
2019	100,829.81	605	718	100,112	19.88	5,036
	4,368,478.17	2,350,225	2,765,837	1,602,641		140,952

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.4 3.23

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 397.00 COMMUNICATIONS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
1998	31,705,051.42	31,705,051	31,705,051			
	31,705,051.42	31,705,051	31,705,051			
AMORTIZED						
SURVIVOR CURVE.. 20-SQUARE						
1999	283,709.99	280,164	276,890	6,820	0.25	6,820
2000	355,890.78	333,648	329,749	26,142	1.25	20,914
2001	129,441.56	114,879	113,537	15,905	2.25	7,069
2002	303,882.38	254,501	251,527	52,355	3.25	16,109
2003	320,223.26	252,176	249,229	70,994	4.25	16,704
2004	12,216.08	9,009	8,904	3,312	5.25	631
2006	10,889.55	6,942	6,861	4,029	7.25	556
2007	47,019.76	27,624	27,301	19,719	8.25	2,390
2008	752,805.28	404,633	399,905	352,901	9.25	38,151
2009	53,906.21	26,279	25,972	27,934	10.25	2,725
2010	576,682.66	252,299	249,351	327,332	11.25	29,096
2011	125,113.02	48,481	47,914	77,199	12.25	6,302
2012	91,544.69	30,896	30,535	61,010	13.25	4,605
2013	153,882.07	44,241	43,724	110,158	14.25	7,730
2014	1,044,719.40	248,121	245,222	799,498	15.25	52,426
2015	80,218.68	15,041	14,865	65,353	16.25	4,022
2016	1,863,148.05	256,183	253,189	1,609,959	17.25	93,331
2017	6,900,672.22	603,809	596,753	6,303,919	18.25	345,420
2018	14,450,816.00	541,906	535,574	13,915,242	19.25	722,870
2019	505,687.37	3,034	2,999	502,689	19.88	25,286
	28,062,469.01	3,753,866	3,710,000	24,352,469		1,403,157
	59,767,520.43	35,458,917	35,415,051	24,352,469		1,403,157

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.4 2.35

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 398.00 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF MARCH 31, 2019

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
1998	290,776.18	290,776	290,776			
	290,776.18	290,776	290,776			
AMORTIZED						
SURVIVOR CURVE.. 20-SQUARE						
1999	355,415.44	350,973	343,893	11,522	0.25	11,522
2000	396,935.69	372,127	364,620	32,315	1.25	25,852
2001	7,974.75	7,078	6,935	1,040	2.25	462
2003	2,391.87	1,884	1,846	546	4.25	128
2006	3,870.08	2,467	2,417	1,453	7.25	200
2009	11,835.34	5,770	5,654	6,182	10.25	603
2010	16,523.53	7,229	7,083	9,440	11.25	839
2011	49,426.61	19,153	18,767	30,660	12.25	2,503
2012	4,333.51	1,463	1,433	2,900	13.25	219
2013	11,933.81	3,431	3,362	8,572	14.25	602
2014	87,699.51	20,829	20,409	67,291	15.25	4,413
2015	168,504.39	31,595	30,958	137,547	16.25	8,464
2016	54,802.03	7,535	7,383	47,419	17.25	2,749
2017	40,261.82	3,523	3,452	36,810	18.25	2,017
2018	47,683.32	1,788	1,752	45,931	19.25	2,386
2019	6,132.57	37	36	6,096	19.88	307
	1,265,724.27	836,882	820,000	445,724		63,266
	1,556,500.45	1,127,658	1,110,776	445,724		63,266

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.0 4.06

JERSEY CENTRAL POWER & LIGHT COMPANY

PROPOSED DEPRECIATION PARAMETERS, ACCRUAL RATES AND ANNUAL ACCRUALS
VS.
CURRENT DEPRECIATION PARAMETERS, ACCRUAL RATES AND ANNUAL ACCRUALS

			PROPOSED					CURRENT				INCREASE/ (DECREASE)
	ACCOUNT	ORIGINAL COST	SURVIVOR CURVE	ANNUAL ACCRUAL AMOUNT	NET SALVAGE NORMALIZATION	TOTAL ACCRUAL AMOUNT	ACCRUAL RATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL ACCRUAL AMOUNT	ACCRUAL RATE	ACCRUAL AMOUNT
	(1)	(2)	(3)	(4)	(5)	(6)=(4)+(5)	(7)	(8)	(9)	(10)=(2)*(11)	(11)	(12)=(6)-(10)
	ELECTRIC PLANT											
	MISCELLANEOUS INTANGIBLE PLANT											
303.00	MISCELLANEOUS INTANGIBLE PLANT	112,020,272.98	7-SQ	8,201,486	0	8,201,486	7.32	N/A	N/A	8,201,486	7.32	0
	TOTAL MISCELLANEOUS INTANGIBLE PLANT	**112,020,272.98**		**8,201,486**	**0**	**8,201,486**	**7.32**			**8,201,486**	**7.00**	**0**
	DISTRIBUTION PLANT											
360.12	DISTRIBUTION SUBSTATION EASEMENTS	690,584.31	80-R4	8,202	0	8,202	1.19	75-R3	0	9,047	1.31	(845)
360.22	DISTRIBUTION LINE EASEMENTS	26,255,822.88	80-R4	159,317	0	159,317	0.61	75-R3	0	191,668	0.73	(32,351)
361.10	STRUCTURES AND IMPROVEMENTS	26,927,888.88	70-R4	274,173	31,464	305,637	1.14	65-R4	0	191,188	0.71	114,449
361.20	STRUCTURES AND IMPROVEMENTS - CLEARING	19,617,181.78	70-R4	275,439	0	275,439	1.40	65-R4	0	139,282	0.71	136,157
362.00	STATION EQUIPMENT	509,243,615.92	59-R2	7,307,941	691,571	7,999,512	1.57	60-R2	0	6,365,545	1.25	1,633,967
364.00	POLES, TOWERS AND FIXTURES	721,698,575.07	49-R1.5	13,139,389	5,405,093	18,544,482	2.57	44-R1.5	0	15,516,519	2.15	3,027,963
365.00	OVERHEAD CONDUCTORS AND DEVICES	903,378,663.86	37-R1	27,867,513	7,170,139	35,037,652	3.88	42-R1	0	17,435,208	1.93	17,602,444
365.10	OVERHEAD CONDUCTORS AND DEVICES - CLEARING	180,229,094.35	65-R5	2,754,241	0	2,754,241	1.53	60-R5	0	2,811,574	1.56	(57,333)
366.00	UNDERGROUND CONDUIT	116,213,888.14	75-R4	1,166,637	24,115	1,190,752	1.02	65-S4	0	1,475,916	1.27	(285,164)
367.00	UNDERGROUND CONDUCTORS AND DEVICES	589,037,199.48	45-S0.5	10,460,527	1,626,491	12,087,018	2.05	43-R2	0	9,483,499	1.61	2,603,519
368.00	LINE TRANSFORMERS	828,017,614.46	39-R1	19,039,292	979,137	20,018,429	2.42	37-R1	0	20,038,026	2.42	(19,597)
369.00	SERVICES	463,545,815.39	60-R2.5	7,102,700	(3,704)	7,098,996	1.53	55-R2.5	0	5,608,904	1.21	1,490,092
370.00	METERS	166,803,742.67	23-L0.5	7,894,528	4,501,792	12,396,320	7.43	24-L0	0	7,956,539	4.77	4,439,781
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	25,623,447.28	28-R2	1,283,921	120,036	1,403,957	5.48	27-R1.5	0	950,630	3.71	453,327
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	222,907,947.91	28-R1.5	7,155,734	1,054,073	8,209,807	3.68	28-R1	0	6,375,167	2.86	1,834,640
373.30	STREET LIGHTING AND SIGNAL SYSTEMS - LED	356,052.66	30-R0.5	11,962	222	12,184	3.42	28-R1	0	10,183	2.86	2,001
	TOTAL DISTRIBUTION PLANT	**4,800,547,135.04**		**105,901,516**	**21,600,429**	**127,501,945**	**2.66**			**94,558,895**	**2.00**	**32,943,050**
	GENERAL PLANT											
389.20	LAND RIGHTS	12,906.25	50-R3	516	0	516	4.00	45-R3	0	399	3.09	117
390.10	STRUCTURES AND IMPROVEMENTS	87,445,213.88	50-R1.5	1,213,261	134,507	1,347,768	1.54	45-R2	0	1,407,868	1.61	(60,100)
390.20	STRUCTURES AND IMPROVEMENTS - CLEARING	12,186,872.61	60-R3	54,662	0	54,662	0.45	60-R2.5	0	56,060	0.46	(1,398)
391.10	OFFICE FURNITURE											
	FULLY ACCRUED	1,282,688.83		0	0	0	-			139,941	10.91	(139,941)
	AMORTIZED	8,921,514.95	25-SQ	356,571	0	356,571	4.00	25-SQ	0	973,337	10.91	(616,766)
	TOTAL OFFICE FURNITURE	10,204,203.78		356,571	0	356,571	3.49			1,113,278	10.91	(756,707)
391.15	OFFICE EQUIPMENT	2,506,944.10	20-SQ	0	0	0 **	-	20-SQ	0	24,067	0.96	(24,067)
391.20	PERSONAL COMPUTERS											
	FULLY ACCRUED	2,684,774.35		0	0	0	-			171,557	6.39	(171,557)
	AMORTIZED	7,698,442.10	5-SQ	1,539,670	0	1,539,670	20.00	5-SQ	0	491,930	6.39	1,047,740
	TOTAL PERSONAL COMPUTERS	10,383,216.45		1,539,670	0	1,539,670	14.83			663,487	6.39	876,183
391.25	INFORMATION SYSTEMS	15,704.47	5-SQ	0	0	0 ***	-	5-SQ	0	0	-	0
392.00	TRANSPORTATION EQUIPMENT	6,179,935.99	13-L2	276,873	(772)	276,101	4.47	14-L1.5	0	697,715	11.29	(421,614)
393.00	STORES EQUIPMENT											
	FULLY ACCRUED	30,113.41		0	0	0	-			943	3.13	(943)
	AMORTIZED	1,497,733.54	30-SQ	49,847	0	49,847	3.33	30-SQ	0	46,879	3.13	2,968
	TOTAL STORES EQUIPMENT	1,527,846.95		49,847	0	49,847	3.26			47,822	3.13	2,025
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT											
	FULLY ACCRUED	624,254.35		0	0	0	-			38,516	6.17	(38,516)
	AMORTIZED	19,505,234.01	25-SQ	779,264	0	779,264	4.00	25-SQ	0	1,203,473	6.17	(424,209)
	TOTAL TOOLS, SHOP AND GARAGE EQUIPMENT	20,129,488.36		779,264	0	779,264	3.87			1,241,989	6.17	(462,725)

JERSEY CENTRAL POWER & LIGHT COMPANY

PROPOSED DEPRECIATION PARAMETERS, ACCRUAL RATES AND ANNUAL ACCRUALS
VS.
CURRENT DEPRECIATION PARAMETERS, ACCRUAL RATES AND ANNUAL ACCRUALS

			PROPOSED					CURRENT				INCREASE/
	ACCOUNT	ORIGINAL COST	SURVIVOR CURVE	ANNUAL ACCRUAL AMOUNT	NET SALVAGE NORMALIZATION	TOTAL ACCRUAL AMOUNT	ACCRUAL RATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL ACCRUAL AMOUNT	ACCRUAL RATE	(DECREASE) ACCRUAL AMOUNT
	(1)	(2)	(3)	(4)	(5)	(6)=(4)+(5)	(7)	(8)	(9)	(10)=(2)*(11)	(11)	(12)=(6)-(10)
395.00	LABORATORY EQUIPMENT											
	FULLY ACCRUED	73,468.10		0	0	0	-			11,953	16.27	(11,953)
	AMORTIZED	451,201.94	20-SQ	22,558	0	22,558	5.00	20-SQ	0	73,411	16.27	(50,853)
	TOTAL LABORATORY EQUIPMENT	524,670.04		22,558	0	22,558	4.30			85,364	16.27	(62,806)
396.00	POWER OPERATED EQUIPMENT	4,368,478.17	20-S1	140,952	(107)	140,845	3.22	20-L2	0	102,659	2.35	38,186
397.00	COMMUNICATION EQUIPMENT											
	FULLY ACCRUED	31,705,051.42		0	0	0	-			1,626,469	5.13	(1,626,469)
	AMORTIZED	28,062,469.01	20-SQ	1,403,157	0	1,403,157	5.00	20-SQ	0	1,439,605	5.13	(36,448)
	TOTAL COMMUNICATION EQUIPMENT	59,767,520.43		1,403,157	0	1,403,157	2.35			3,066,074	5.13	(1,662,917)
398.00	MISCELLANEOUS EQUIPMENT											
	FULLY ACCRUED	290,776.18		0	0	0	-			3,955	1.36	(3,955)
	AMORTIZED	1,265,724.27	20-SQ	63,266	0	63,266	5.00	20-SQ	0	17,214	1.36	46,052
	TOTAL MISCELLANEOUS EQUIPMENT	1,556,500.45		63,266	0	63,266	4.06			21,169	1.36	42,097
	TOTAL GENERAL PLANT	**216,809,501.93**		**5,900,597**	**133,628**	**6,034,225**	**2.78**			**8,527,951**	**4.00**	**(2,493,726)**
	UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION											
391.10	OFFICE FURNITURE			148,234 ****		148,234 ****				0		148,234
391.15	OFFICE EQUIPMENT			113,765 ****		113,765 ****				0		113,765
391.20	PERSONAL COMPUTERS			1,952,859 ****		1,952,859 ****				0		1,952,859
391.25	INFORMATION SYSTEMS			209 ****		209 ****				0		209
393.00	STORES EQUIPMENT			(13,941) ****		(13,941) ****				0		(13,941)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT			137,204 ****		137,204 ****				0		137,204
395.00	LABORATORY EQUIPMENT			(40,288) ****		(40,288) ****				0		(40,288)
397.00	COMMUNICATION EQUIPMENT			359,526 ****		359,526 ****				0		359,526
398.00	MISCELLANEOUS EQUIPMENT			(20,407) ****		(20,407) ****				0		(20,407)
	TOTAL UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION			**2,637,161**		**2,637,161**				**0**		**2,637,161**
	TOTAL DEPRECIABLE ELECTRIC PLANT	**5,129,376,909.95**		**122,640,760**		**144,374,817**	**2.81**			**111,288,332**	**2.00**	**33,086,485**
	NONDEPRECIABLE PLANT											
301.00	ORGNAIZATION	49,293.00										
302.00	FRANCHISES AND CONSENTS	16,447.00										
360.10	LAND	5,714,032.19										
374.00	ARC DISTRIBUTION PLANT	45,656.70										
389.10	LAND	1,488,774.98										
397.10	COMMUNCATOIN EQUIPMENT - FIBER OPTIC											
399.10	ARC GENERAL PLANT	1,465,281.77										
	TOTAL NONDEPRECIABLE PLANT	**8,779,485.64**										
	TOTAL ELECTRIC PLANT	**5,138,156,395.59**		**122,640,760**	**21,734,057**	**144,374,817**				**111,288,332**		**33,086,485**

* Assets within the amortization period utilized a 14.29% annual accrual rate consistent with the amortization period.
** Assets as of January 1, 2019 will utilize a 5.00% annual accrual rate consistent with the amortization period.
*** Assets as of January 1, 2019 will utilize a 20.00% annual accrual rate consistent with the amortization period.
**** 4-Year amortization of unrecovered reserve related to amortization accounting. Amortization will begin January 1, 2021 and end December 31, 2024 to be consistent with associated Transmission filing period.

EXHIBIT JC-15

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In The Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony
of
Olenger L. Pannell

Re: Service Company Relationships, Charges and Allocations

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Olenger L. Pannell. My business address is 76 South Main Street, Akron, OH 44308.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company (the "Service Company") as an Assistant Controller in the FirstEnergy Controllers Group within the Service Company. In that position, I serve as (i) the Controller for Jersey Central Power & Light Company ("JCP&L" or the "Company"), a New Jersey electric utility and a wholly-owned subsidiary of FirstEnergy Corp. ("FirstEnergy"), a holding company under the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), and (ii) Assistant Controller for the FirstEnergy Utilities Group ("FEU"), which includes FirstEnergy's operating utility companies, including JCP&L and FirstEnergy Transmission ("FET"), which entities, together, represent the regulated side of FirstEnergy's business and are further described below.

Q. What are your responsibilities as Assistant Controller of FEU?

A. In my position as Assistant Controller in the FirstEnergy Controllers Group within the Service Company, I am responsible for financial reporting and analysis (both internal and external), business planning, budgeting and forecasting, and regulated accounting functions, as well as Sarbanes-Oxley ("SOx"), Generally Accepted Accounting Principles ("GAAP") and FirstEnergy accounting policy compliance. I also provide reports through the FirstEnergy Controller to FirstEnergy senior management and FirstEnergy's Board of Directors regarding financial matters associated with the FEU and FET groups. In my position as Assistant Controller in the FirstEnergy Controllers Group within the Service

Company, I supervise a staff of approximately 59 employees, primarily comprised of accounting and financial analyst professionals.

Q. What are your responsibilities as Controller of JCP&L?

A. In serving as the Controller of JCP&L, I have the primary responsibility for the delivery of the same types of services mentioned above for FEU, directly to, and for, JCP&L, including providing reports to JCP&L's Board of Directors.

Q. Can you further describe what you mean when you refer to the FirstEnergy Controllers Group, FEU and FET?

A. Yes. The FirstEnergy Controllers Group is an organizational grouping within the Service Company utilized for coordinating and/or standardizing controller-related services, policies and procedures throughout the FirstEnergy holding company system. The Controller functions, which are provided by the Service Company for FirstEnergy and its associate companies,[1] participate in this group under the leadership of the FirstEnergy Controller and Chief Accounting Officer.

FEU and FET are two other organizational groupings within the FirstEnergy holding company system comprising the regulated segments of FirstEnergy's business, which include FirstEnergy's ten electric distribution companies, including JCP&L, FirstEnergy's regulated transmission companies, and FirstEnergy's regulated generation facilities.

Q. Have you previously testified in proceedings before the New Jersey Board of Public Utilities ("Board" or "BPU")?

A. No, I have not previously testified in any prior proceedings before the BPU.

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[1] The term "associate companies" generally refers to all companies within a public utility holding company system.

Q. What is your professional and educational background?

A. A description of my professional and educational background is attached to this testimony as Appendix A.

Q. Please describe the purpose of your direct testimony.

A. My testimony is intended to provide support to JCP&L in its base rate filing proceeding in my roles as its Controller and as Assistant Controller at the Service Company regarding the services that were provided, and the costs that were charged to JCP&L by the Service Company under the Service Agreement (as discussed below) during the Test Year. In doing so, I will discuss the process for charging the Service Company costs for those services to JCP&L and its affiliates within the FirstEnergy holding company system. In this regard, I will also review the manner in which the Service Company fairly and equitably charges the costs for its services directly and/or indirectly to JCP&L and to FirstEnergy and its other affiliates that receive such services, including the cost allocation methodologies for charging indirect costs. My testimony also addresses two pro forma adjustments being made related to Service Company costs in the context of JCP&L's base rate filing.

Q. Please briefly summarize your testimony.

A. First, I provide background as to JCP&L's affiliation within the FirstEnergy holding company system. Second, I describe the role of the Service Company in the FirstEnergy System, including providing a general description of the centralized services that are provided to JCP&L and to FirstEnergy and its other affiliates by the Service Company. Third, I discuss the accounting methodologies used to account for and assign costs from the Service Company to JCP&L and to FirstEnergy and its other affiliates, in accordance with the Service Agreement approved by the Board. Fourth, I discuss the Test Year costs charged and allocated to JCP&L from the Service Company, which total $117,534,907, and two proposed pro forma adjustments affecting JCP&L's base rate filing, totaling approximately $5.25 million. Finally, I discuss the various controls in place to monitor Service Company charges and ensure that such charges are properly assigned and charged to JCP&L and to FirstEnergy and the rest of the FirstEnergy System.

II. BACKGROUND

Q. Please describe the FirstEnergy holding company system.

A. For the purposes of this testimony, the FirstEnergy holding company system is comprised of FirstEnergy and its associate companies. FirstEnergy is a diversified energy company that, through its associate companies, owns and operates both regulated and non-regulated businesses that are involved in the generation, transmission and distribution of electricity, as well as energy management and other energy-related services (collectively, the "FirstEnergy System").

Q. Please describe the dimensions of the FirstEnergy System.

A. FirstEnergy's regulated business is comprised of ten regulated electric distribution companies that serve customers in New Jersey, Ohio, Pennsylvania, Maryland, West Virginia, and New York. FirstEnergy's wholly-owned regulated electric distribution companies (JCP&L, Metropolitan Edison Company, Pennsylvania Electric Company, The Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, West Penn Power Company, The Potomac Edison Company, and Monongahela Power Company) serve approximately six million customers in the Midwest and Mid-Atlantic regions covering 65,000 square miles across six states. FirstEnergy also owns three regulated independent transmission businesses, which have approximately 24,000 miles of high-voltage lines and three regional transmission operation centers within the PJM Interconnection, LLC ("PJM") region. PJM is the regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.[2]

Q. In addition to its regulated business, does the FirstEnergy System also have unregulated businesses?

A. Yes. After the completion of the FirstEnergy Solutions ("FES") bankruptcy and the transfer to FES of the competitive Pleasants Power Station, FirstEnergy anticipates that it will have completed its exit from non-regulated generation production. At that point, upon the completion of FES's emergence from bankruptcy as a fully separate entity, unregulated business will comprise a significantly smaller portion of the FirstEnergy System.

Q. Please describe the role of the Service Company within the FirstEnergy System.

A. The Service Company is a centralized service provider formed for the purpose of providing administrative, management, operations support and other services to FirstEnergy and its associate companies. It has been long understood[3] that providing the broad array of services described herein throughout a holding company system, such as the FirstEnergy System, by and through a centralized mutual service company, such as the Service Company, is more efficient and less costly than providing, managing and staffing such services at each individual associate company.

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[2] It should be noted that not all of the FirstEnergy transmission assets are part of the three independent transmission businesses. Some of FirstEnergy's distribution utilities, including JCP&L, currently own their own transmission assets for which they are provided with transmission support services through the Service Company, and the costs for such transmission support services are addressed in proceedings related to transmission rates before the FERC and not as part of this proceeding. However, I should also clarify that the same personnel who provide the transmission support services, which are not addressed in this proceeding, also provide some distribution support services, which are addressed in this proceeding.

[3] For instance, the predecessor to PUHCA 2005, the Public Utility Holding Company Act of 1935 ("the '35Act"), and the regulations (*e.g.*, Rules 87, 88, 90, 91 and 93) promulgated thereunder, permitted, and regulated, the use of, and charging of costs by, mutual service companies that provided services within registered public utility holding company systems.

The FirstEnergy System is also able to take advantage of its economies of scale to more efficiently utilize its resources by providing such services from centralized groups within the Service Company. For instance, among other things, the Service Company has a greater degree of bargaining power with suppliers than would each of FirstEnergy and its associate companies negotiating individually, because the Service Company negotiates, where appropriate, on behalf of the overall FirstEnergy System.

Q. Please be more specific about the types of services centrally provided by the Service Company to FirstEnergy and its associate companies, including JCP&L.

A. The Service Company provides various corporate, managerial and administrative support services to FirstEnergy and its associate companies, including JCP&L, in the following areas: administrative services, business development, call centers, claims, communications, controllers, corporate and shareholder services, corporate affairs and community involvement, credit management, energy delivery and customer service, economic development, enterprise risk management, governmental affairs, human resources, industrial relations, information services, insurance services, internal audit, investment services, investor relations, legal, performance planning, rates and regulatory affairs, real estate, supply chain, technologies support, telecommunications support, transmission & distribution technical services, construction and design services, treasury and workforce development.[4]

A full list and description of the services provided by the Service Company are set forth in Exhibit A to the Service Agreement (as defined below) that is attached hereto as Schedule OLP-1.

[4] Please note that the Service Company also provides, on a limited basis, goods in connection with such services. However, for the sake of simplicity and clarity, I only refer to "services" in my testimony.

Q. Does the Service Company perform utility operations services for JCP&L or any other of the FirstEnergy utility companies?

A. Although the Service Company provides utility operations-related ***support*** services, it is important to emphasize that the Service Company, generally, does not perform the "operations" services, which are, instead, performed by the FirstEnergy utility companies themselves, including JCP&L. One exception to this, however, is in the area of vegetation management on the FirstEnergy bulk transmission system, which is centrally managed at the Service Company for the entities, such as JCP&L, comprising the FEU and FET groups, which own the bulk transmission assets.

III. <u>SERVICE COMPANY COST ACCOUNTING</u>

Q. Are you familiar with the Service Company's books and records and how they are maintained?

A. Yes, I am. The books and records of the Service Company are maintained in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USofA") and GAAP.

Q. Can you please provide an overview of how the Service Company accounts, and charges, for the costs of its services?

A. Yes. The Service Company renders services to FirstEnergy and its associate companies at cost. The full costs of the services provided by the Service Company are either directly or indirectly charged to FirstEnergy and its associate companies. Some Service Company costs are directly charged to a particular company, such as, for instance, JCP&L, because those costs are related to services performed solely for JCP&L. An example of such a direct charge is the charge for substation engineering, where a group of Service Company employees based in New Jersey provide substation engineering services exclusively for JCP&L. Each of those employees effectively directly charges his or her time to JCP&L.

Other Service Company costs are indirectly charged when the costs are not directly chargeable to a single associate company because the services benefit multiple associate companies and the particular costs of the service is not identified to any individual associate company or companies. One example of such indirectly charged costs is an employee's work associated with the preparation of the SEC 10-K annual report. Such an employee's time would be indirectly charged to FirstEnergy and its associate companies using cost allocation methodologies that I discuss herein.

As I will further explain, the processes for accounting for, and charging, the Service Company costs, including the cost allocation methodologies for charging indirect charges, are integrated into the FirstEnergy SAP Enterprise Resource Planning system ("SAP"), which is FirstEnergy's comprehensive system-wide management software system.

Q. Please further clarify what you mean by "directly charged."

A. When I say that a cost is "directly charged," I am using that terminology to convey that the time and expenses associated with the service are charged directly to the identifiable associate company for which the service is being rendered. The costs of services are charged directly to the associate company receiving the services or for a particular transaction, even when more than one associate company is receiving the same services at the same time.

Q. Please further clarify what you mean by "indirectly charged."

A. When I say that a cost is "indirectly charged", I am using that terminology to convey that the charges are not specifically directly charged to a single associate company. In such cases, one could also say that such cost is "allocated" or "charged on an allocated basis."

While these terms can be used interchangeably, I have attempted to be consistent in using the term "indirectly charged" in order to simplify the distinction between such charges and those that are directly charged. For instance, it is sometimes said that one cost is "directly charged" while another cost is "indirectly allocated." This combination of terms may create confusion that I am hoping and attempting to avoid.

Q. Are the terms "directly charged" and "indirectly charged" the same as "direct costs" and "indirect costs"?

A. No. The former terms are methods of charging. The latter terms are types of costs. Since I have explained the former terms, I will also explain the latter terms.

Direct costs are costs that can be specifically identified with a particular service performed for an associate company. Costs incidental or related to direct items are also classified as direct costs. Direct costs may be directly charged if reasonably identifiable to a particular recipient associate company; otherwise direct costs are indirectly charged using an approved cost allocation methodology.

Indirect costs are costs of a general overhead nature such as support costs that cannot be identified with a particular service. This includes but is not limited to overhead costs (*i.e.*, payroll, stores handling, construction), administrative and general expenses, and various taxes. Costs incidental or related to indirect items are also classified as indirect costs. Indirect costs may be directly charged if reasonably identifiable to a particular recipient associate company; otherwise indirect costs are indirectly charged using an approved cost allocation methodology.

Q. What are the components of the service costs that are charged by the Service Company, whether charged directly or indirectly?

A. Service costs are fully loaded, meaning that they include the direct costs incurred to provide a service plus the indirect costs (such as appropriate overheads) incidental or related to a service whether charged directly or indirectly.

Q. When a service is provided to a group of companies does the Service Company directly or indirectly charge the costs for such service?

A. It depends. If the costs can be reasonably identified and related to the particular transaction for the particular individual associate companies, then the costs are directly charged to each individual associate company in the group. If they cannot, then the costs must be indirectly charged using an appropriate cost allocation methodology. However, I wish to emphasize that whenever practicable (to the extent excessive effort or expense is not required), costs that can be identified as related to a particular service provided to a particular associate company are directly charged to that associate company. But, to repeat, where the costs cannot be so identified, they are indirectly charged using an approved cost allocation methodology.

Q. What do you mean by "cost allocation methodology"?

A. A "cost allocation methodology" is a method or process for distributing costs for services rendered that are not directly charged to a single associate company, such as charges to multiple associate companies, which are indirectly charged.

Q. Where are the Service Company cost allocation methodologies found?

A. The cost allocation methodologies used by the Service Company today are set forth in the FirstEnergy Service Company Service Agreement (Service Agreement), and are the same ones that were approved by the SEC in 2003 and by the Board in a December 14, 2005 order, BPU Docket Nos. EM02100777 and EE98050267 (the "December 2005 Order"). The cost allocation methodologies are also listed in the FERC Form 60, which the Service

Company uses to report to the FERC annually, a copy of which is also provided to the Board and the Division of Rate Counsel. A copy of the FERC Form 60 for 2019 encompassing part of the Test Year is being finalized for filing with FERC and will be filed as a supplement, as schedule OLP-2 as soon as it is available. As I discuss further below, the FirstEnergy cost allocation methodologies and the procedures for using them are maintained and reviewed annually by the FirstEnergy General Accounting Group which is within the FirstEnergy Controllers Group.

Q. How does the Service Company use cost allocation methodologies?

A. The Service Company has no earnings, renders services at cost to FirstEnergy and its associate companies and, therefore, all of its costs must be fairly and equitably distributed to FirstEnergy and its associated companies. The cost allocation methodologies are used to accurately distribute those costs that are not directly charged to a particular associate company, and, therefore, are indirectly charged to, and among, the FirstEnergy associate companies in compliance with the standards promulgated by FERC under PUHCA 2005 (including cost allocation methodologies previously approved by the SEC under the ‘35Act and applicable state requirements, including, in the case of JCP&L, the December 2005 Order). The particular cost allocation methodology used with respect to any particular service varies based on the service provided and the associate company or companies receiving the service.

Q. How many cost allocation methodologies does the Service Company use?

A. As described in the Service Agreement, the Service Company has eighteen cost allocation methodologies available for use to appropriately and accurately distribute the costs of services, which are to be indirectly charged to and among FirstEnergy and its associate companies.

Q. Does the identity of the recipient associate company play a role in determining the use of a cost allocation methodology?

A. Yes. For example, if a service is being provided only to an unregulated segment of FirstEnergy's business, then the costs that need to be indirectly charged in a general manner would be indirectly charged using the "Multiple Factor-Non-Utility" cost allocation methodology so that such costs are not borne by any of the FirstEnergy utilities in the regulated segment.

Q. Are the cost allocation methodologies grouped together in any way that is helpful to understanding how they work?

A. Yes. Seven of the cost allocation methodologies pertain to information technology services. Four are used as general cost allocation methodologies with respect to costs that are not readily identifiable with particular cost drivers (*i.e.,* a measurable event or quantity that can influence the level of costs incurred for or by a particular activity and which can be directly traced to the origin of the costs themselves). The remaining seven cost allocation methodologies are identifiable to particular cost drivers.

Q. How are the cost allocation methodologies related to the services provided by the Service Company?

A. The Service Agreement lists the service categories and particular types of services along with a general description of the services and a reference to the cost allocation methodology (or methodologies) that is/are most likely to be used for costs associated with such services that are to be indirectly charged.

Q. Are the cost allocation methodologies changed regularly or periodically?

A. No.

Q. Does any aspect of the cost allocation process change from time to time?

A. While the cost allocation methodologies themselves have not changed, the data inputs required to apply the cost allocation methodologies do change on an annual basis based on actual experience. For example, the general cost allocation methodology "Multiple Factor–Utility" requires an averaging of three factors related to a FirstEnergy utility's percentage share of all of the FirstEnergy utilities' plant, operations and maintenance expenses, and revenues. This data will vary from year to year based upon actual results of operations. As a result, while the methodologies would not change, the percentage share for an associate company and the percentage allocation among associate companies within the methodology can change from year to year.

Q. Earlier you referred to SAP. Please explain how FirstEnergy uses SAP.

A. SAP is the FirstEnergy resource planning software system that links and coordinates business processes to perform core business functions such as, for example, maintaining a general ledger, financial reporting, human resources management, inventory management, and purchasing transactions in a fully integrated enterprise management system. When initially installed (at GPU in 1999 and FirstEnergy in 2003), SAP replaced other software systems that were not fully integrated or which required interfaces to integrate. SAP has been maintained through regular functional enhancements (multiple releases per year) to support business operations as well as implementing major version updates (the most recent of which was completed in 2015) that introduce new business functionality.

SAP is used to manage work, share information, track customer accounts, and meet other business needs. SAP contains the functions and processes for capturing, reporting and directly charging and indirectly charging the Service Company costs to and among FirstEnergy and its associate companies. SAP is currently organized to maintain, among other things, (i) separation of costs between FirstEnergy's regulated and non-regulated associate companies, and (ii) an adequate audit trail on the books and records of FirstEnergy and its associate companies.

Q. Please discuss the role of cost collectors.

A. Attributing and charging costs accurately to FirstEnergy and its associate companies requires the costs to be captured in SAP. This is the job of cost collectors, which are accounting devices used to plan, track, and account for costs of different categories or types of work. Cost collectors include orders, work breakdown structures ("WBS") and cost centers. Only one of these three types of cost collectors can be entered on a document during data entry. Orders (*i.e.*, a sales, production, process, purchase, internal, or work order that uniquely identifies a cost source) and WBSs (*i.e.*, a cost collector that organizes in a hierarchy the actions and activities to be carried out in a project) are temporary cost collectors because the costs accumulated using these cost collectors ultimately settle to a balance sheet account or to a cost center. A cost center is the principal type of cost collector, where the costs of providing services are accumulated to be either directly charged or indirectly charged.

Q. Please describe the use of cost centers.

A. As I said, cost centers are the principal type of cost collector in SAP. Within SAP, cost centers are assigned to departments and/or managers responsible for certain areas of the business such as functional areas within, for example, human resources, finance, facilities, information systems, administrative support, and legal. Each employee within the FirstEnergy System, including at the Service Company, is assigned to a cost center that relates to the area of the business or category of service for which they are responsible (*e.g.*, human resources, legal, treasury).

The cost center provides the mechanism for collecting the costs associated with those employees and the services that they provide, including overheads, incidental and related costs. All employees are required to ensure that their time in providing services is captured (*i.e.*, by recording the time spent on various tasks on a timesheet).

In the case of the Service Company, this also means identifying the appropriate cost center for the associate company, or companies, receiving such services. Ultimately, both the service provider cost center and the service recipient cost center track, bill/receive bills for, and collect/make the payments for the costs associated with the services rendered.

Q. Are the descriptions and uses of cost centers reviewed periodically?

A. Yes. As part of FirstEnergy's annual SOx control reviews, General Accounting performs an annual review of the allocation methodologies used for indirect charges to determine whether 1) billing allocators are still valid; 2) new allocations are needed; and 3) cost centers are using the correct billing factors. Additional details about this annual review of cost centers are provided in the "Controls" section of my testimony below.

Q. Are employee timesheets subject to review?

A. Yes. Supervisory review of employee timesheets is regularly performed to assure that time charged is appropriate and the cost center (or other cost collector) being used is proper. This includes review of the time document charges in relationship to employees' work schedules. In addition, cost center time sheet evaluations are completed each year to ensure the appropriate charging is taking place.

Q. Besides timesheets, are there other sources of costs captured in SAP?

A. Other-than-labor costs are accounted for in SAP based on expense reports, vendor invoices and journal entries. The costs associated with these sources would also flow to appropriate cost centers for tracking, billing and collection.

Q. How are costs transferred in SAP from the Service Company to JCP&L?

A. In responding to this question, it may be helpful to recall my earlier discussion of the Service Company costs that are directly or indirectly charged. The Service Company costs are accumulated in the cost centers and other relevant cost collectors and are either (i) "directly charged", for those costs originating within the Service Company that relate to services that are identified as benefiting only JCP&L (for instance), or (ii) "indirectly charged" using appropriate general and/or specific cost allocation methodologies associated with the services rendered, where the costs are identified as benefitting JCP&L **and** one or more of FirstEnergy and its other associated companies.

Q. Were changes made to Service Company cost allocations as a result of the strategic changes FirstEnergy has undergone because of the FES bankruptcy?

A. Yes. In anticipation of the impacts of the competitive generation business bankruptcy (FES/FENOC), FirstEnergy launched an initiative called "FE Tomorrow" to, among other things, re-align the Service Company shared service organization in its support of the remaining FirstEnergy primarily regulated businesses. As part of the initiative, approximately $300M of shared service costs were identified as supporting the competitive generation business and strategies were put in place to eliminate such costs consistent with the reduction and elimination of the need for such support by FES/FENOC. These shared services costs were previously directly billed to FES/FENOC and were not allocated to other FirstEnergy associate companies, including JCP&L. Specifically, as a result of this effort, shared service headcount and costs have been reduced by approximately 40%.

Q. What is the current status of the FES Bankruptcy matter in terms of continuing to receive services from the Service Company?

A. As part of the definitive settlement agreement filed with the bankruptcy court on August 24, 2018, an Amended Shared Service Agreement (the "ASSA") was reached between the FES/FENOC debtors-in-possession and the Service Company, which provides FES/FENOC the right to continue receiving and paying for (through the existing allocation methodology) shared services from the Service Company until June 30, 2020. Additionally, FES/FENOC has the right to terminate, prior to June 30, 2020, any group of shared services (as outlined in the ASSA) on 90-days written notice. Since December 2018, FES/FENOC has provided 90-day notice for certain shared service functions, which the Service Company has ceased providing.

Q. Will there be any cost reallocations from the Service Company to JCP&L after the termination of shared services to FES?

A. Yes. Service Company costs that would have been allocated to FES/FENOC will be reallocated to the remaining FE subsidiaries, including JCP&L, after support to FES/FENOC is terminated. These costs are related to the operations and maintenance ("O&M") associated with Service Company functions such as finance, audit, and information technology services, and depreciation of information technology systems that were commonly used by both FES/FENOC and FirstEnergy and its other associate companies, including JCP&L. Once FES/FENOC is no longer supported by the Service Company, FES/FENOC will no longer be utilizing these common and remaining services and systems, and the revenue requirement impact of these costs to JCP&L is estimated to be approximately $5.1 million per year. It is anticipated that this adjustment will become effective during 2020 and is further detailed in Ms. Pittavino's testimony on adjustments 16 and 23 (Exhibit JC-4).

Q. Do you anticipate any further changes in the organizational structure of the Service Company after June 30, 2020?

A. No. The Service Company is currently sized to support the current and the currently anticipated configuration of the FirstEnergy System.

IV. <u>SERVICE COMPANY COSTS IN THE TEST YEAR</u>

Q. Please summarize the direct and indirect Service Company costs to JCP&L in the Test Year.

A. During the Test Year, the Service Company charges amount to a total of $117,534,907 charged to JCP&L. This total amount includes Service Company costs related to transmission, which are recovered through transmission rates. As explained in Ms. Pittavino's testimony, the transmission-related Service Company costs included in the above amount have been removed from JCP&L's request as part of this proceeding. Of the total amount, $32,784,830 are direct charges to JCP&L primarily for services from the Service Company's Transmission & Distribution ("T&D") group for distribution support services, the information technology group, the corporate services and Chief Information Officer function, and the legal department. The remaining $84,750,077 in costs are indirect charges to JCP&L primarily for services from the Service Company's customer service function, the information technology group, the T&D group, the corporate controller function and the human resources group using appropriate cost allocation methodologies found in the Service Agreement.

Q. Are any of the indirect Service Company costs allocated to FirstEnergy Corp.?

A. Yes. In accordance with the December 2005 Order, five percent (5%) of the indirect charges from the Service Company related to products and/or services that benefitted the entire FirstEnergy System are allocated to FirstEnergy. The remaining indirect charges are allocated to the appropriate FirstEnergy subsidiaries, which may include JCP&L, in accordance with the approved methodologies set forth in the Service Agreement.

Q. Can you provide additional detail regarding the Service Company charges that were assigned to JCP&L?

A. Yes. The following table (Table OLP-1) provides a breakdown of these Test Year charges by Service Company department or function. The description of functional services in the Service Agreement describes the services that are associated with these charges. It should be noted that the ratio of indirect to direct costs for the Test Year is likely affected by the mix of actual (last six months of 2019) and budgeted (first six months of 2020) data insofar as the budgeted data is not as readily susceptible to a determination as to whether it will be directly charged or indirectly charged -- a determination that is more precisely made at the time of the delivery of the services. As such, the 12+0 update to revenue requirements that the Company will provide in this case will reflect the actual amounts that are directly and indirectly charged during the test year.

Table OLP-1

Service Company Costs
Test Year - July 1, 2019-June 30, 2020

Department or Function	Direct	Indirect	Grand Total
Chairman of the Board	$ -	$ 147	$ 147
President & CEO, FirstEnergy Service Company	$ -	$ 349,076	$ 349,076
President, FE Utilities	$ 29,868	$ 232,472	$ 262,341
Transmission, Distribution Support	$ 14,862,739	$ 19,586,708	$ 34,449,447
Utility Operations	$ 19,443	$ 747,950	$ 767,393
Compliance & Reg. Services	$ 146,111	$ 2,299,314	$ 2,445,425
Customer Service	$ 1,165,623	$ 13,483,877	$ 14,649,501
Energy Efficiency	$ 85,532	$ 633,701	$ 719,234
Environmental	$ 446,088	$ 1,586,817	$ 2,032,905
EVP & Chief Financial Officer	$ -	$ 152,587	$ 152,587
Corporate Services & CIO	$ 7,684,122	$ 15,741,038	$ 23,425,160
Supply Chain	$ 301,088	$ 440,087	$ 741,175
Controller	$ 488,107	$ 6,891,791	$ 7,379,898
Treasury	$ 2,093	$ 423,104	$ 425,197
Corporate Risk	$ 3,092	$ 611,315	$ 614,407
Business Development	$ -	$ 569,286	$ 569,286
Integrated System Planning & Development	$ 36,089	$ 506,400	$ 542,490
Internal Auditing	$ 2,073	$ 612,370	$ 614,443
Legal	$ 2,483,823	$ 1,717,764	$ 4,201,587
Rates & Regulatory Affairs	$ 1,422,416	$ 354,394	$ 1,776,810
Corporate, Real Estate, Records Management	$ 1,072,768	$ 3,667,641	$ 4,740,409
External Affairs & Communications	$ -	$ 4,511,717	$ 4,511,717
Corporate Affairs & Community Involvement	$ 1,291	$ 1,399,621	$ 1,400,913
Federal Affairs & Energy Policy	$ 2,397	$ 309,579	$ 311,976
Local Affairs & Economic Development	$ 11,079	$ 172,015	$ 183,093
Human Resources	$ 97,641	$ 7,203,114	$ 7,300,755
State Affairs	$ 475,918	$ 112,060	$ 587,977
FE Generation & CNO	$ 1,945,428	$ 434,132	$ 2,379,560
Total	**$ 32,784,830**	**$ 84,750,077**	**$ 117,534,907**

Q. Are there any other Service Company costs that are not captured in the above table that JCP&L is proposing to include in its rates?

A. Yes. As mentioned in the testimony of Carol A. Pittavino, JCP&L is proposing an adjustment to capture certain expenses that were initially charged to FirstEnergy by the Service Company in the Test Year. These expenses are for Audit Fees for services provided by Pricewaterhouse Coopers ("PwC") which benefitted the entire FirstEnergy System, including JCP&L. The Multiple Factor – All allocation was used to assign JCP&L its portion of the expenses for the adjustment. The use of this allocation means that 5% of the costs will remain assigned to FirstEnergy in accordance with the Service Agreement, as discussed earlier in my testimony. The total amount of this proposed adjustment is $147,821. FirstEnergy incurred these costs for services that benefit the entire FirstEnergy System and would have to have been performed by each individual company within the system absent the use of the holding company structure. Accordingly, in this instance, the assignment of the FirstEnergy portion of these costs to the other entities within the FirstEnergy System through use of the Multiple Factor – All allocator is appropriate.

Q. What is the percentage of directly charged costs as compared to indirectly charged costs to JCP&L?

A. The following table (Table OLP-2)[5] provides a perspective on the distribution of costs from the Service Company to JCP&L for the Test Year as compared to the actual results for 2018 in terms of directly charged, indirectly charged and total costs:

Table OLP-2 ($)

	JC DIRECT	JC INDIRECT	TOTAL	DIRECT %	INDIRECT %
2018	33,469,695	91,363,255	124,832,950	26.81%	73.19%
TEST YEAR	32,784830	84,750,077	117,534,907	27.89%	72.11%

As mentioned above, the ratio of indirect to direct costs for the Test Year is likely affected by the mix of actual (last six months of 2019) and budgeted (first six months of 2020) data, which is not as readily susceptible to a determination as to whether and the extent to which it will be directly charged or indirectly charged -- a determination, as I

[5] Table OLP-2 represents all charges to JCP&L on an actual GAAP basis.

stated above, that is made at the time of delivery of the services. For example, looking at actual results for 2018 indicates that the ratio of direct and indirect costs was 26.81% direct and 73.19% indirect, which is consistent with the ratio of direct and indirect costs in the Test Year.

Q. Can you provide any additional perspective regarding the direct and indirect Service Company charges to JCP&L reflected in the Test Year amounts?

A. Yes, I can. I believe that it is helpful to consider Service Company costs charged to JCP&L in the context of the overall operations and maintenance costs of JCP&L in order to understand the relationship of the Service Company costs to JCP&L's total cost of operations, comprised of JCP&L's own cost of operations together with the Service Company's charges. In addition, because costs directly charged by the Service Company to JCP&L are, in essence, functionally equivalent to JCP&L's own (local) cost of operations, this view also provides additional perspective on the ratio of directly charged and indirectly charged costs from the Service Company. Consistent with the Service Company's role as a mutual service company, the services that give rise to these Service Company costs, particularly the indirectly charged costs are, predominantly, shared services that are less likely to be directly charged.

As shown in the table below (Table OLP-3) the Service Company's total charges to JCP&L during the Test Year represent only 15.5% of JCP&L's total Test Year cost of operations (excluding generation and purchase power expenses). More specifically, the Service Company's total indirectly charged O&M costs to JCP&L during the Test Year, including transmission-related costs that are not being requested as part of this proceeding, represented only approximately 12.4% of JCP&L's total cost of operations:

Table OLP-3[6]

Cost Category	JCP&L	%
Total T&D Operations & Maintenance	$ 402,997,726	84.5%
Service Company (O&M Direct)	14,940,858	3.1%
Service Company (O&M Indirect)	58,909,008	12.4%
Total Costs	$ 476,847,593	100.0%

Our annual cost center review process, which I discussed earlier, encourages the use of the most appropriate charging method given the nature of the costs and whether the cost is identifiable only to JCP&L and the results indicated above are consistent with that encouragement.

V. CONTROLS

Q. Are the Company's books and records audited by an independent accounting firm?

A. Yes. PwC audited the Company's financial statements included in the Company's 2018 10-K and FERC Form No. 1, as to which PwC concluded that the Company's financial statements present fairly, in all material respects, the financial position in conformity with GAAP and in accordance with accounting requirements of the FERC's USofA. PwC will also audit the Company's financial statements for 2019, which audit results will be issued in early 2020.

Q. Please address the controls that are in place with respect to charges and expenses that the Service Company either directly charges or indirectly charges to JCP&L.

A. The General Accounting function within the Controller's department is responsible for maintaining the cost allocation methodologies, which includes, among other things:

1. Annually reviewing cost allocation methodologies utilized with each service provided to determine if the most appropriate allocation methodology is being

[6] The total of these (*i.e.*, $476,847,726) is consistent with, and relies on, the amount set forth in Schedule CAP-1 (column 1, rows 7 to 12) as set forth in the direct testimony of Carol A. Pittavino, Exhibit JC-4.

utilized and that the appropriate associate companies are being billed for services performed. New allocation methods, if any, are identified, but cannot be used until approved, as necessary, by the necessary regulatory authorities. The results of this annual review are discussed with and reviewed by PwC.

2. Testing and validating that overhead and allocation results are reasonable. During the monthly closing process, the overhead activity is reviewed to determine that the results are appropriate and complete.
3. Monitoring and maintaining existing overheads and allocations to ensure sender (source) amounts are being applied or allocated appropriately.
4. Performing steps required to apply overheads to direct costs.

In addition, JCP&L utilizes other control mechanisms that monitor the services being provided by the Service Company. These control mechanisms include billing and review procedures to ensure the accuracy of the Service Company billings and internal/external audit examinations.

Q. Please describe the billing process as a control mechanism.

A. The Service Company billings to JCP&L are generated on the basis of cost centers, work orders and time records. As mentioned earlier, the time documents are subject to review and approval by the supervisor or manager responsible for the employees completing such time records. In addition, the Service Company billings to JCP&L are reviewed and approved by the FEU Business Services group, which reports to me. The FEU Business Services group analyzes each month's Service Company billing summaries to JCP&L to ensure billing to the proper company and alignment or variance from budget. If required, detailed Service Company information (*i.e.*, time sheets, invoices) is available to the FEU Business Services group for further analyses.

Q. Please describe the billing reconciliation procedures as a control mechanism.

A. Another control that is performed every month is the reconciliation of the Service Company billings to the Service Company expenses with regard to services rendered to the FEU group of utilities, including JCP&L. Such reconciliation ensures that all expenses have been billed appropriately, and it also detects any over- or under-billings for any cost center.

Q. Please describe the audit process as a control over the Service Company charges to JCP&L.

A. The internal auditing department periodically reviews the Service Company charges, including its audits, to assess the design and operating effectiveness of the control environment for Service Company charges, which are processed through SAP. In general, the main objectives of the internal audit review are to determine whether internal controls over the billing process to FEU, including JCP&L, are adequate and effective, as well as to review the cost allocation methodologies then in effect and the application of these methodologies. This would include a review to ensure compliance with applicable regulatory requirements as well as with the Service Company policies and procedures pertaining to billing. The specific audit procedures to be utilized will typically include interviews, observations, tests and other procedures deemed necessary to accomplish the audit objectives.

Q. Can you elaborate further regarding the use of the audit process as a control?

A. Yes. Since 2005, the internal auditing department has conducted SOx control tests annually to ensure the appropriate use of cost allocation methodologies within SAP and that the SAP system is distributing costs correctly and in accordance with the SOx controls set in place to assure compliance with the PUHCA 2005.

Q. Can you discuss the use of this control relative to JCP&L?

A. Yes. The Internal Auditing department completed an audit of JCP&L's internal controls related to the Company's Cost Allocation Manual ("CAM") in 2017. The audit determined that the internal controls that support and govern the cost allocation process are adequately designed to provide a reasonable level of assurance regarding the reliability and integrity of the allocation of the charges billed to JCP&L, in accordance with the Service Agreement and CAM requirements.

The last external audit related to Service Company charges overseen by the Board was the Management Audit conducted by Schumaker & Company during the 2010-2011 period as reflected in the Schumaker Management Audit Report issued in June 2011. Furthermore, the Company is currently undergoing an audit by the FERC Division of Audits for the period January 1, 2015 through December 31, 2019, with a subsequent report expected to be issued in 2020 which will include selective tests of the Service Company cost allocation methodologies and charges billed by the Service Company to the FEU utilities.

Finally, as part of the annual review of JCP&L's overall financial condition and the results of operations of JCP&L, individual audit opinions are issued annually by an independent public accounting firm.

Q. Have these completed audits and reviews indicated any issues with the amounts of, or manner of charging Service Company charges?

A. No. Neither the reviews or the audits have generated any issues or concerns with the process or calculations used in the allocation charges. The application of the cost allocation methodology and cost review also have been determined to be consistent with the approved processes.

Q. Do you have any conclusions about the degree and extent of the controls in place?

A. In my view, as JCP&L's Controller, JCP&L has ample control over the Service Company costs. First, JCP&L reviews on a monthly basis the amounts the Service Company bills to it. Second, the cost collector system, billing review and reconciliation procedures, as well as the periodic audits performed by the internal audit function and external auditors, provide more than adequate opportunities for effective communications, decisions or other actions pertaining to quantity and coordination of service issues between JCP&L and the Service Company. Third, executive and director level oversight is provided by senior management and the Boards of Directors. All provide a comprehensive framework for assuring the fairness and reasonableness of the charges for the services provided to JCP&L by the Service Company.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Appendix A

PROFESSIONAL AND EDUCATIONAL BACKGROUND

OF

OLENGER L. PANNELL

I have been employed by a FirstEnergy System company since 2001, when I joined the Unregulated Commodity Operations organization supporting FirstEnergy Solutions ("FES") and FirstEnergy Generation ("FEG"), which were part of FirstEnergy's unregulated business. Since joining FirstEnergy, I have held various analyst positions within Commodity Operations and Supply Planning. In 2007, I served as Acting Manager of Supply Planning at FES. In 2009, I served as Manager of FES/FEG Forecast/Analysis/Budget as part of the FirstEnergy Service Company. At FirstEnergy Service Company I served in 2013 as the Forecasting and Reporting business lead for the Financial Transformation project in Information Technology, which was a project performed to focus the Finance organization on more analytical capabilities that support business decision making through the use of simplified, streamlined and standardized software and technology. My role on the team was to manage the implementation and integration of a best in class financial modeling tool designed to automate and standardize the creation of projected integrated financial statements to enable FirstEnergy to prepare business segment developed multi-year planning forecasts. The tool allows FirstEnergy to dynamically model financial scenarios aiding in decision making and risk mitigation strategy development. In 2014, I was Manager of Short-Term Budget & Forecast; in 2016, I was promoted to Director of Business Planning and Performance; in February 2018, I was named to my current position, which is Assistant Controller for FEU Finance and Controller for JCP&L. In terms of my education, I have a Bachelor of Science degree in Business Administration from The Ohio State University, with a focus in marketing and logistics.

SERVICE AGREEMENT

This Service Agreement ("Agreement") is entered into as of the 25th day of February, 2011, by and between each of the associate companies listed on the signature page hereto (each a "Client Company"), and FirstEnergy Service Company, an Ohio corporation ("Service Company").

WHEREAS, Service Company is a direct wholly-owned subsidiary of FirstEnergy Corp., a holding company under the Public Utility Holding Company Act of 2005, as amended (the "Act");

WHEREAS, Service Company has been formed for the purpose of providing administrative, management and other services to FirstEnergy Corp. and its associate companies, including Client Company (together, the "Client Companies"); and

WHEREAS, Client Company believes that it is in its interest to enter into an arrangement whereby Client Company may agree to purchase such administrative, management and other services from Service Company as Client Company may choose at cost as determined in accordance with this Agreement and the Act;

NOW, THEREFORE, in consideration of the mutual covenants contained herein and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

1. <u>DESCRIPTION OF SERVICES.</u>

Service Company agrees to provide certain administrative, management or other services (the "Services") to Client Company similar to those supplied to other Client Companies of Service Company. Such services are and will be provided to Client Company only at the request of Client Company. Exhibit A hereto lists and describes all of the Services that are available from Service Company.

2. <u>PERSONNEL.</u>

In order to provide the Services, Service Company will employ executive officers, accountants, financial advisers, technical advisers, attorneys and other persons with the necessary qualifications. If necessary, Service Company may also arrange for the services of nonaffiliated experts, consultants and attorneys in connection with the performance of any of the Services provided under this Agreement.

3. COMPENSATION AND ALLOCATION.

As and to the extent required by law, Service Company provides and will provide such services at fully allocated cost, determined in accordance with the Act. Exhibit A hereof contains rules for determining and allocating such costs.

4. TERMINATION AND MODIFICATION.

Either party to this Agreement may terminate this Agreement by providing 60 days written notice of such termination to the other party. This Agreement is subject to termination or modification at any time to the extent its performance may conflict with the provisions of the Act or with any rule, regulation or order of the Federal Regulatory Energy Commission (the "Commission") adopted before or after the making of this Agreement. This Agreement shall be subject to the approval of any state commission or other state regulatory body whose approval is, by the laws of said state, a legal prerequisite to the execution and delivery or the performance of this Agreement.

5. SERVICE REQUESTS.

Client Company and Service Company will prepare a Service Request on or before September 30th of each year listing Services to be provided to Client Company by Service Company and any special arrangements related to the provision of such Services for the coming year, based on Services provided during the preceding year. Client Company and Service Company may supplement the Service Request during the year to reflect any additional or special Services that Client Company wishes to obtain from Service Company, and the arrangements relating thereto.

6. BILLING AND PAYMENT.

Unless otherwise set forth in a Service Request, payment for Services provided by Service Company shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of Client Company and Service Company. Billing will be made on a monthly basis, with the bill to be rendered as soon as practicable after the close of the month, and remittance or accounting entries completed within 30 days of billing. Any amount remaining unpaid after 30 days following receipt of the bill shall bear interest thereon from the due date of the bill until payment at a rate equal to the prime rate on the due date.

7. NOTICE.

Where written notice is required by this Agreement, all notices, consents, certificates, or other communications hereunder shall be in writing and shall be deemed given when mailed by United States registered or certified mail, postage prepaid, return receipt requested, addressed as follows:

To Client Company: c/o President
76 South Main St.
Akron, Ohio 44308

To Service Company: c/o Vice President and Controller
76 South Main Street
Akron, Ohio 44308

8. GOVERNING LAW.

This Agreement shall be governed by and construed in accordance with the laws of the State of Ohio, without regard to its conflict of laws provisions.

9. MODIFICATION.

No amendment, change or modification to this Agreement shall be valid, unless made in writing and signed by both parties hereto.

10. ENTIRE AGREEMENT.

This Agreement, together with its exhibits, constitutes the entire understanding and agreement of the parties with respect to its subject matter, and effective upon the execution of this Agreement by the respective parties hereof, any and all prior agreements, understandings or representations with respect to this subject matter are hereby terminated and canceled in their entirety and are of no further force and effect, except to the extent transactions thereunder have taken place prior to such effective date in which case such agreements will govern the terms of such transactions.

11. WAIVER.

No waiver by either party hereto of a breach of any provision of this Agreement shall constitute a waiver of any preceding or succeeding breach of the same or any other provision hereof.

12. ASSIGNMENT.

This Agreement shall inure to the benefit and shall be binding upon the parties and their respective successors and assigns. No assignment of this Agreement or either party's rights, interests or obligations hereunder may be made without the other party's consent, which shall not be unreasonably withheld, delayed or conditioned.

13. SEVERABILITY.

If any provision or provisions of this Agreement shall be held by a court of competent jurisdiction to be invalid, illegal, or unenforceable, the validity, legality, and enforceability of the remaining provisions shall in no way be affected or impaired thereby.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed effective as of the 25th day of February, 2011. This Agreement supercedes any previous agreement between the Service Company and the Client Companies.

FirstEnergy Service Company

By: ______________________
Harvey L. Wagner
Vice President & Controller

Client Companies:

Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company
Pennsylvania Power Company
American Transmission Systems, Incorporated
Pennsylvania Electric Company
Waverly Electric Power & Light Company
Metropolitan Edison Company
Monongahela Power Company
The Potomac Edison Company
West Penn Power Company
PATH - Allegheny Land Acquisition Company
PATH Allegheny Maryland Transmission Company, LLC
PATH Allegheny Transmission Company, LLC
PATH Allegheny Virginia Transmission Corporation
AYE Series, Potomac-Appalachian Transmission Highline, LLC
Trans-Allegheny Interstate Line Company

By: ______________________
Charles E. Jones
President

Jersey Central Power & Light Company

By: Donald M. Lynch
Donald M. Lynch
President

EXHIBIT A
DESCRIPTION OF SERVICES AND ALLOCATION METHODOLOGY

1. Description Of Services

Overview

This Exhibit provides a description of all services provided by Service Company departments and the cost allocation methodologies to be used in connection therewith. All products and services are subject to Service Level Standards as negotiated between the Service Company department and Client Company. Each Client Company is classified as either a "Utility Subsidiary" or a "Non-Utility Subsidiary".

2. Cost Allocation Methodology

Overview

The costs of services provided by Service Company will be directly assigned, distributed or allocated by activity, project, program, work order or other appropriate basis. The primary basis for charges to affiliates is the direct charge method. The methodologies listed below pertain to all other costs which are not directly assigned but which make up the fully allocated cost of providing the product or service. The costs of product and services provided by the ServeCo that cannot be charged directly to the Subsidiary receiving the product or service will be allocated among the associate companies by utilizing one of the methods described below that most accurately distributes the costs. The method of cost allocation varies based on the department rendering the service. The allocation methods used by Service Company are as follows:

a. **"Multiple Factor – All"** - For the Indirect Costs for products or services benefiting the entire FirstEnergy system, FirstEnergy and all Subsidiaries will bear a fair and equitable portion of such costs. FirstEnergy will bear 5% of these Indirect Costs. The remaining Indirect Costs will be allocated among the Utility Subsidiaries and the Non-Utility Subsidiaries benefiting from the services provided based on FirstEnergy's equity investment in the respective groups. A subsequent allocation step will then occur. Among the Utility Subsidiaries, allocations will be based upon the **"Multiple Factor - Utility"** method. Among the Non-Utility Subsidiaries, allocations will be based upon the **"Multiple Factor - Non-Utility"** method.

b. **"Multiple Factor – Utility"** - For the Indirect Costs for a product or service solely benefiting one or more of the Utility Subsidiaries, each such Utility Subsidiary so benefiting will be charged a portion of the Indirect Costs based on the sum of the weighted averages of the following factors:

1. Gross transmission and/or distribution plant
2. Operating and maintenance expense excluding purchase power and fuel costs

3. Transmission and/or distribution revenues, excluding transactions with affiliates

These three (3) factors have been determined to be the most appropriate for the Utility Subsidiaries in the FirstEnergy system. Each factor will be weighted equally so that no one facet of the electric utility operations inordinately influences the distribution of Indirect Costs.

c. **"Multiple Factor - Non-Utility"** - For the Indirect Costs for products or services solely benefiting the Non-Utility Subsidiaries, each Non-Utility Subsidiary so benefiting receiving the product or service will be charged a proportion of the Indirect Costs based upon the total assets of each Non-Utility Subsidiary, including the generating assets under operating leases from the Utility Subsidiaries.

d. **"Multiple Factor - Utility and Non-Utility"** - For the Indirect Costs for a product or service benefiting one or more of the Utility and Non-Utility Subsidiaries, each such Subsidiary so benefiting is first- assigned a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in such Subsidiaries. Following this distribution, a subsequent allocation step will then occur. Among the Utility Subsidiaries, allocations will be based upon the **"Multiple Factor-Utility."** Among the Non-Utility Subsidiaries, allocations will be based upon **"Multiple Factor - Non-Utility"**

e. **"Direct Charge Ratio"** - The ratio of direct charges for a particular product or service to an individual Subsidiary as a percentage of the total direct charges for a particular product or service to all Subsidiaries benefiting from such services. Indirect Costs are then allocated to each Subsidiary based on the calculated ratios.

f. **"Number of Customers Ratio"** - For costs of products and services driven by the number of Utility customers, the allocation method that will be used will be the number of Utility customers for the respective Utility Subsidiary receiving the product or service divided by the total number of utility customers.

g. **"Number of Shopping Customers Ratio"** - A "shopping customer" is defined as a Utility customer who has selected a competitive electric generation supplier. For costs of products and services driven by the number of shopping customers, the allocation method that will be used will be the number of shopping customers for the respective Utility Subsidiary receiving the product or service divided by the total number of shopping customers.

h. **"Number of Participating Employees – General"** - For costs of products and services driven by all participating employees within the FirstEnergy system, the allocation method that will be used will be the number of participating employees for the respective Subsidiary receiving the product or service divided by the total number of participating employees.

i. **"Number of Participating Employees - Utility and Non-Utility"** - For costs of products and services driven by participating employees who work for the Utility and Non-Utility Subsidiaries, the Subsidiaries receiving the product or service are first assigned a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in the respective groups. Costs are further allocated by using the number of participating employees for the respective Subsidiary divided by the total number of participating FirstEnergy employees.

j. **"Gigabytes Used Ratio"** - Number of gigabytes utilized by a Subsidiary receiving the product or service divided by the total number of gigabytes used by the FirstEnergy system companies applicable to that respective product or service.

k. **"Number of Computer Workstations Ratio"** - Number of computer workstations utilized by a Subsidiary receiving the product or service divided by the total number of computer workstations in use by the FirstEnergy system companies applicable to that respective product or service.

l. **"Number of Billing Inserts Ratio"** - Number of billing inserts performed for a Subsidiary receiving the product or service divided by the total number of billing inserts performed for the FirstEnergy system companies applicable to that respective product or service.

m. **"Number of Invoices Ratio"** - Number of invoices processed for a Subsidiary receiving the product or service divided by the total number of invoices processed for the FirstEnergy system companies applicable to that respective product or service.

n. **"Number of Payments Ratio"** - Number of monthly payments processed for a Subsidiary divided by the total monthly number of payments processed for the FirstEnergy system companies applicable to that respective product or service. This will not be utilized until some historical information is available out of our new automated system.

o. **"Daily Print Volume"** - Average daily print volume performed for a Subsidiary receiving the service divided by the total average daily print volume performed for the entire FirstEnergy system.

p. **"Number of Intel Servers"** - Number of Intel servers utilized by a Subsidiary receiving the product or service divided by the total number of Intel servers utilized by the FirstEnergy system.

q. **"Application Development Ratio"** - Number of application development hours budgeted for a Subsidiary receiving the service divided by the total number of budgeted application development hours for the year.

r. **"Server Support Composite"** - The average ratio of unix gigabytes, SAP gigabytes and Intel number of servers for a Subsidiary receiving the service.

3. **Descriptions of Products and Services**

CALL CENTER

Product or Service	Product / Service Description	Indirect Allocation Methods
Field All Inbound Regulated Calls	Field calls related to billing, credit, new service, service order completion, outages, and other miscellaneous activities.	Multiple Factor – Utility and Non-Utility
Field All Inbound Unregulated Calls	Field calls related to billing, credit, new service, service order completion, outages, and other miscellaneous activities.	Multiple Factor – Utility and Non-Utility

CUSTOMER SERVICE

Product or Service	Product / Service Description	Indirect Allocation Methods
Supplier Services	Provide customer services support to electric generation suppliers, administer and maintain Electronic Data Interface (EDI) functions and invoice suppliers.	Number of Shopping Customers Ratio
Regulatory Interface and Process Improvement: Supplier	Liaison to ensure Customer Choice requirements and develop and execute plans to improve supplier services processes.	Number of Shopping Customers Ratio
Market Support Generation (MSG) Administration	Administer and support MSG supplier functions.	Number of Shopping Customers Ratio
Regulatory Interface and Process Improvement: Regulatory	Respond to regulatory complaints from customers and develop and execute plans to improve regulatory compliance processes.	Number of Customers Ratio
Compliance	Work with regions to communicate and ensure regulatory requirements.	Multiple Factor – Utility
Power Billing	Provide billing functions for large commercial/industrial contract customers.	Number of Customers Ratio
Revenue Reporting	Perform and manage revenue reporting functions.	Number of Customers Ratio
Billing Exception Processing	Process billing exceptions.	Number of Customers Ratio
Remittance Processing	Process customer payments and deposit funds.	Number of Payments Ratio
Human Services	Coordinate and administer the various social services programs.	Number of Customers Ratio

Arrears Management/ Outsourcing Services Incorporated (OSI) Administration	Coordinate and perform arrears, credit and bankruptcy functions. Manage outside collections agencies' performance and OSI credit activities.	Number of Customers Ratio
Revenue Protection Administration	Perform revenue reporting and compliance functions.	Number of Customers Ratio
Metrics and Budget/ Customer Satisfaction Measurement	Manage Customer Services and Call Center Departments' budgets and measure performance and customer satisfaction results.	Number of Customers Ratio
Policy/Procedures Development and Documentation	Develop, document and communicate Customer Services policies and procedures.	Number of Customers Ratio
Bill Administration/ Forms Administration	Design standardized customer bills, envelopes, and forms.	Number of Customers Ratio
Meter Reading Support	Coordinate Meter Reading schedules and routing activities.	Number of Customers Ratio
Customer Information System (CIS) Control	Operate and maintain CIS.	Number of Customers Ratio

ECONOMIC DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Economic Development Services	Foster economic development to encourage capital investment in FirstEnergy's service areas.	Multiple Factor – Utility

TRANSMISSION & DISTRIBUTION TECHNICAL SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Forestry	Provide forestry services.	Multiple Factor – Utility
Distribution Reliability and Asset Records	Services include Joint User contracts, public works coordination, reliability reporting to regions and Public Utility Commissions, mutual assistance coordination, PowerOn support, cable locate ticket screening and tariff support.	Multiple Factor – Utility

Design Standards	Services include line material and construction standards, distribution line and underground maintenance practices and support, new business process support, and service practices.	Multiple Factor – Utility
Substation Services Support	Services include Substation maintenance plan coordination, practices and support, mobile substation administration and planning, and environmental compliance support.	Multiple Factor – Utility
Equipment Repair/Testing Services	Services include the maintenance, installation, maintenance, testing and repair of utility equipment.	Multiple Factor – Utility
Fleet Services	Develop fleet strategy, and perform fleet maintenance practices and support.	Multiple Factor – Utility
Financial Services	Identify revenue enhancements and cost reductions.	Multiple Factor – Utility
Substation Design and Transmission-Line Maintenance Support	Perform substation and transmission line design and project management and transmission line and substation design and material standards, right-of-way and survey services, transmission line maintenance plan coordination, practices and support, FAA activity coordination.	Multiple Factor – Utility
Planning and Protection	Perform planning and protection support for subtransmission system and overall radial system capacity planning overview, and interconnection coordination for distributed technology applications on distribution system.	Multiple Factor – Utility
Capital Budget and Equipment Support	Capital budget development and support, and major equipment specifications and procurement/repair activities for major equipment.	Multiple Factor – Utility

WORKFORCE DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Transmission and Distribution Skills Training	Develop and facilitate technical and safety training for workers associated with distribution activities, including line, substation, meter, fleet, warehouse, field engineering, and dispatch. Provide support through equipment evaluation, training analyses, job assessments, and project coordination.	Number of Participating Employees – General
Customer Service Skills Training	Develop and facilitate skills training for customer service groups.	Multiple Factor – Utility
External Learning Opportunities Through the Power Systems Institute	Develop educational partnerships with colleges to offer two-year degrees in electric utility technology.	Multiple Factor – Utility

ADMINISTRATIVE SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Administrative Support Services	Provides services in production printing, document imaging, graphic services, food services, corporate mailroom and corporate courier.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Provide Records Management Services	Provides services in records storage, records retrieval, records retention, records planning and engineering records.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Provide Business Services	Provides services in convenience copiers, fax machines, pagers, printers, and business information center.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*

* For services rendered only to the utilities.

EXECUTIVE

Product or Service	Product / Service Description	Indirect Allocation Methods
Executive Management	Consultation and services in management and administration of all aspects of the business.	Multiple Factor – All

COMMUNICATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Public Relations	Provides services in media relations, financial communications, annual reports, executive presentation, public relations counsel, corporate writing, internet support and special projects.	Multiple Factor – All
Employee Communications	Provides services with update, retirees, satellite broadcast, human resource-related communications and special projects.	Number of Participating Employees – Utility and Non-Utility
Production	Provides services related to display, photography, Corporate ID, video and employee merchandise.	Multiple Factor – All
Sponsorship	Provides services related to sports marketing, university support and special projects.	Multiple Factor – All
Non-Utility Advertising	Provides services related to broadcast/print, collateral, direct mail, internet/intranet, display/merchandise, yellow/white pages, production/agency support and special projects.	Multiple Factor – Non-Utility
Utility Advertising	Provides services related to TV, radio, print, outdoors, Internet/Intranet, special projects, production, agency support and creative media placement.	Multiple Factor – Utility
Utility Bill Inserts	Provides services developing regulated bill service to Ohio, Pennsylvania and New Jersey.	Multiple Factor – Utility
Utility : Yellow / White Pages	Provides services with regulated yellow/white pages.	Multiple Factor – Utility
Utility: Research	Provides research services.	Multiple Factor – Utility
Ohio Consumer Education	Provides services related to Ohio Consumer Education statewide and locally.	Multiple Factor – Utility
Ohio Deregulation Education	Provides service related to Deregulation Education.	Multiple Factor – Utility

CORPORATE AFFAIRS AND COMMUNITY INVOLVEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Corporate Affairs Activities	Provide administrative support through oversight of the business practices and planning and implementation of staff, senior management and related meetings. Serves as community liaison.	Multiple Factor – Utility
Direct Community Involvement Initiatives	Provides direction in employee volunteerism, supports viable community partnerships and educational initiatives.	Multiple Factor – Utility
Energy Efficiency Programs	Directing and coordinating Ohio Weatherization and Energy Efficiency Programs for Low Income Customers.	Multiple Factor – Utility
Community Initiatives Consulting Services	Consults to regional operations and other business units and client managers for the various community programs.	Multiple Factor – Utility
Contributions Management	Directs, coordinates, monitors, and manages contributions.	Multiple Factor – Utility

CORPORATE

Product or Service	Product / Service Description	Indirect Allocation Methods
Investor Services	Stock administration, perform recordkeeping, transfer agent, registrar, paying agent, reinvestment plan administration and other services for shareholders.	None (All Direct Charge to Holding Co.)
Board of Directors Support	Support and administration of Board of Directors meetings and director compensation.	None (All Direct Charge to Holding Co.)
Annual Meeting Coordination	Coordinate the Annual Meeting of Shareholders, including the preparation and mailing of proxy materials and annual reports and the tabulation of proxies.	None (All Direct Charge to Holding Co.).
Indenture Compliance	Administer the company's indentures	Multiple Factor – Utility

HUMAN RESOURCES

Product or Service	Product / Service Description	Indirect Allocation Methods
Manage Employee Executive Compensation and Benefits	Provide management and supervision for employee and executive compensation and benefits.	Number of Participating Employees – General
Manage Workers Compensation and Disability Management	Provide management and supervision for workers compensation and disability programs.	Number of Participating Employees – General
Provide and Coordinate Human Resources Training	Design, prepare and conduct training.	Number of Participating Employees – General
Provide Employment Services	Provide staffing, relocation and employment expertise.	Number of Participating Employees – General
Provide HRIS Services	Provide and maintain Human Resources information.	Number of Participating Employees – General
Provide Diversity Management Services	Manage Affirmative Action programs, provide EEO/AA consulting services, and respond to charges.	Number of Participating Employees – General
Manage/ Administer Medical Services and Wellness Programs	Establish compliance, develop, implement, and administer medical and wellness programs.	Number of Participating Employees – General

INDUSTRIAL RELATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Labor Contract Negotiations	Provide contract negotiation services for all labor agreements.	Number of Participating Employees – General
Provide Labor Consulting Services	Provide labor consulting services.	Number of Participating Employees – General
Manage/Administer Safety Programs	Develop, implement and administer occupational safety programs.	Number of Participating Employees – General

REAL ESTATE

Product or Service	Product / Service Description	Indirect Allocation Methods
Facilities Management	Management and maintenance of office facilities.	Multiple Factor – All or Multiple Factor Utility*
Facilities Planning and Project Management	Manage office design services, furniture, project management and other capital improvements.	Multiple Factor – All or Multiple Factor Utility*
Management of Real Estate Assets	Support internal and external inquiries regarding the acquisition, divestiture and management of real estate assets	Multiple Factor – All or Multiple Factor Utility*
Manage/Administer Security Programs	Administer physical security, special investigations, security audits, security consultation and contract guard services.	Multiple Factor – All or Multiple Factor Utility*

* For services rendered only to the utilities.

FIRSTENERGY TECHNOLOGIES

Product or Service	Product / Service Description	Indirect Allocation Methods
Strategic Technologies	Develop, support and implement EPRI programs, industry initiatives, research and development programs, collaboratives and activities with universities, labs and the Department of Energy.	Multiple Factor – Utility
New Technology Assessment	Perform assessment activities for strategic technology pilots, technology assessments, marketing tests, customer pilots and due diligence reviews.	Multiple Factor – Utility and Non-Utility
Technical Application and Product Innovation	Develop, analyze and support strategic alliances, joint ventures, strategic startups, direct investments and Portfolio initiatives.	Multiple Factor – Utility and Non-Utility
New Technology and Product Market Deployment	Develop, support and implement the following initiatives: tailored solutions with existing products, commercial packages, operational efficiencies and business area solutions.	Multiple Factor – Utility and Non-Utility
Demand Response Initiatives	Provide support for corporate demand response initiatives.	Multiple Factor – Utility and Non-Utility
Renewable Energy Program and Strategy	Provide support for various corporate and regulatory initiatives to develop and implement renewable energy programs and products.	Multiple Factor – Utility

Regulated Programs and Services	Develop, support and implement programs and strategies to meet corporate initiatives and regulatory mandates and commitments related to Comprehensive Resource Assessment(CRA), customer end-use. technology, distributed generation and load management.	Multiple Factor – Utility
Project Implementation Management Services	Develop and implement end-use and distributed generation technology-based products and services.	Multiple Factor – Utility and Non-Utility

TECHNOLOGY & SUPPORT SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Network Services	Provide Internal Network Services.	Multiple Factor – Utility and Non-Utility
Maintain wireless cell sites and fiber optics network	Maintain internal wireless cell sites and fiber optic network; provide engineering, procurement, and installation services.	Multiple Factor – Utility and Non-Utility

INFORMATION TECHNOLOGY

Product or Service	Product / Service Description	Indirect Allocation Methods
Application Development	Create new or enhance existing applications; including analysis design coding, testing, system integration, and implementation, as well as any required technical writing or project manual development.	Directly Billed
Development Supervision and Tool Support	Supervision of application development employees and the support of development software tools.	Application Development Ratio
Server Support (Unix, SAP)	Create and support the network and server infrastructure to accommodate unix and SAP client server applications.	Gigabytes Used Ratio
Client Server Storage Support	Support of storage requirements for all server applications.	Server Support Composite Ratio
Server Support (Intel)	Create and support the network and server infrastructure to accommodate windows and NT client server applications.	Number of Intel Servers Ratio
Mainframe Processing and Storage Support	Execute mainframe applications, including an appropriate portion of support, started tasks, mainframe backups and microfiche services.	Gigabytes Used Ratio

Desktop Support	Help desk email and end-user tools, remote access, repair services, and general workstation support.	Number of Computer Workstations Ratio
Network Services	Includes voice, data, EMS and radio access.	Direct Charge Ratio
Inserting Services	Provide document bursting, inserting and mailing.	Number of Billing Inserts Ratio
Printing Services	Provide mainframe and client server printing services at the data center.	Daily Print Volume Ratio
Technical Consulting	Provide consulting support to departments and end-users to enable them to leverage their IT capabilities. Provide advice and consultation regarding desktop setups and configurations.	Directly Billed
Training	Provide IT training.	Multiple Factor – Utility and Non–Utility
Business Application Support	Support business application related software licenses and / or hardware maintenance provided by an outside vendor.	Directly Billed
Data Security	Disaster recovery and data security services.	Multiple Factor – Utility and Non-Utility
Project Management Office	Oversee technology projects through benefit.	Multiple Factor – Utility and Non-Utility
Provide Telecommunication Services	Provide telecommunication services and equipment.	Direct Charge Ratio
Portal Support	Support the infrastructure to accommodate internet and intranet application access.	Multiple Factor – Utility and Non-Utility

PERFORMANCE PLANNING

Product or Service	**Product / Service Description**	**Indirect Allocation Methods**
Performance Planning Services	Develop, support and execute performance planning services.	Multiple Factor – All

SUPPLY CHAIN

Product or Service	Product / Service Description	Indirect Allocation Methods
Strategic Planning, Demand management and Procurement Projects	Provide assistance in materials and services planning (demand management) and performs special procurement projects.	Multiple Factor – Utility and Non-Utility
Goods and services procurement	Procure material, equipment and contractor services. Establish, manage and administer programs, which allow internal customers to obtain goods without having to process the need through Procurement. Develop specifications, construction standards, schedules, and bills of materials.	Multiple Factor – Utility and Non-Utility
Materials Management Support	Maintain the computerized purchasing and materials management systems, and material related modules; maintain and/or modify select management reports. Analyze Supply Chain processes and measure performance. Monitor and forecast demand to ensure a continuous supply of materials.	Multiple Factor – Utility and Non-Utility
Investment Recovery Projects	Develop and implement plans for disposition of surplus assets.	Multiple Factor – Utility and Non-Utility
Process, Refurbish and Sell Materials	Perform recovery processing, investment recovery processing, refurbishing and selling materials.	Multiple Factor – Utility and Non-Utility
Provide Warehousing Services - Non-nuclear	Receive and place material into stock, insure quality requirements are met at receipt, maintain inventory counts, and update information systems. Fill customer requests for material from stock.	Multiple Factor – Utility and Non-Utility
Provide Warehousing Services - Nuclear	Receive and place material into stock, insure quality requirements are met at receipt, maintain inventory counts, and update information systems. Fill customer requests for material from stock.	None (All direct charged)
Warehousing Space Charge	Provide warehousing space to internal customers.	Multiple Factor – Utility and Non-Utility

CONTROLLERS

Product or Service	Product / Service Description	Indirect Allocation Methods
Accounting Research	Provide accounting research and consulting to ensure compliance with existing and proposed financial reporting, and regulatory accounting requirements.	Multiple Factor - All
Accounts Payable	Nonpayroll corporate disbursement services including account distribution to the general ledger. Resolve problems associated with invoice processing and maintain the accounts payable system.	Multiple Factor - All
Billing Services	Prepare non-retail electric billings.	Multiple Factor Utility
Infrastructure and Corporate Reporting, Accounting and Budgeting	Prepare Corporate Sustaining reports, subsidiary accounting and corporate budgeting, which includes reporting and support of the ledger, property records and SAP system.	Multiple Factor - All
Due Diligence	Assist value centers to determine whether proposed business acquisitions/combinations and similar transactions are desirable from a financial perspective; extensive review/analysis following preliminary review and firm intent to proceed with transaction through commitment and closing phases.	None (All direct charged)
Value Center Accounting and Budgeting	Maintain the property accounting system and provide value center accounting such as management reporting.	Multiple Factor – Utility and Non-Utility
Property Record Maintenance	Maintain corporate continuing property records.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Tax Consulting and Research	Conduct tax research and tax consulting to assure compliance with statues, while evaluating alternative tax strategies within the constraints of regulations that provide additional shareholder value to the company. In addition, provide tax-consulting advice to the value centers on tax compliance and reporting issues, which includes business "start-up" support to organizations requiring assistance.	Multiple Factor – All

* For services rendered only to the utilities.

Tax Compliance	Prepare and process all schedules and information associated with corporate and subsidiary tax returns, audits, and tax litigation, assuring compliance with tax regulations and statues.	Multiple Factor – All or Multiple Factor Utility*

* For services rendered only to the utilities.

CREDIT MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Credit Analysis and Supporting Functions	Provide detailed written credit analysis issuing recommendations on counterparty creditworthiness and assigning credit limits.	Multiple Factor – Utility and Non-Utility
Credit Policies and Procedures	Develop and support credit policies and procedures for managing credit risk. Implement and support standardized credit approval processes.	Multiple Factor – Utility and Non-Utility
Credit Management Information System	Develop and support credit management reports and calculate credit exposure on a corporate wide basis.	Multiple Factor - All

ENTERPRISE RISK MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
General Risk Management	Develop and maintain an enterprise risk management system.	Multiple Factor - All

INSURANCE SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Insurance Policies	Manage and support insurance policies for all the business units.	Multiple Factor – Utility and Non-Utility
Loss Control Services	Manage and support property inspections to prevent losses.	Multiple Factor – Utility and Non-Utility
Surety Bonds	Manage and support Surety Bonds.	Multiple Factor– Utility and Non-Utility
Risk Transfer and Risk Mitigation Services	Manage and support risk transfer and risk mitigation services.	Multiple Factor – Utility and Non-Utility
Ancillary Coverages	Manage and support ancillary coverages.	None (All direct charged)

INTERNAL AUDIT

Product or Service	Product / Service Description	Indirect Allocation Methods
Audit Services	Perform the following internal audit services based on risk levels and / or requests: financial, performance analysis, safeguarding of assets, computer- related and fraud investigations.	Multiple Factor -- All or Multiple Factor – Utility*

INVESTMENT MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Qualified and Non-qualified Pension and Savings Plan	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Number of Participating Employees – Utility and Non–Utility
FirstEnergy Foundation	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor - All
Voluntary Employee Benefit Association (VEBA) Trust	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Number of Participating Employees – Utility and Non–Utility
Nuclear Decommissioning	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	None (All direct charged)
Non-Utility Generator Trust	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor – Non-Utility
Spent Nuclear Fuel	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	None (All direct charged)
Low-Income Housing Tax Credit Partnership	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor - All

INVESTOR RELATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Investor Information	Compile and communicate information to investors.	Multiple Factor – Utility* or Direct Charge to Holding Co.
Investor Education	Target and educate potential investors to promote FirstEnergy's valuation characteristics and business strategy.	None (All Direct Charge to Holding Co.)

* For services rendered only to the utilities.

Regulations Compliance	Ensure compliance with SEC Fair Disclosure regulations.	Multiple Factor - All

FirstEnergy Management Education	Provide education to management of business concerns and valuation issues of analyst/investors	Multiple Factor – All
FirstEnergy Employee Education	Actively promote understanding of financial and investor relations' issues.	Multiple Factor – All

RATES AND REGULATORY AFFAIRS

Product or Service	Product / Service Description	Indirect Allocation Methods
Regulatory Activities and Consulting	Manage regulatory activities and interfaces, including tariff development and interpretation. Monitor and participate in regulatory affairs at the local, state and federal levels.	Multiple Factor – Utility
Customer Pricing and Contracting	Develop pricing programs for regulated electric service for retail and wholesale customers, including "unbundled" costs and prices for generation, transmission and distribution service and support justification to regulators. Provide support in developing pricing for special-purpose customer programs and non-regulated energy services (e.g. prepayment, economic development, interruptible load, conjunctive-billing electric service programs).	Multiple Factor – Utility
Billing Support	Provide assistance calculating customer (external and internal) invoices and operate and maintain systems to render, collect and account for these invoices.	Multiple Factor – Utility
Sales and Load Forecasting	Develop short-term and long-term sales forecast, peak load projections and customer counts	Multiple Factor – Utility and Non-Utility

TREASURY

Product or Service	Product / Service Description	Indirect Allocation Methods
Capital Structure Management and Administration	Perform all activities related to acquiring capital and establish and administer funding, legal documentation, and record-keeping activities associated with finance programs	Multiple Factor – All
Corporate Funds Management	Plan, manage, and operate the corporate "cash-flow-cycle."	Multiple Factor – All
Corporate Forecasting	Provide regulatory support, strategy support, financial modeling and forecasting, financial and economic analysis and development of annual corporate KPI target.	Multiple Factor – All

Capital Project Evaluation and Support	Provide analytical support in the areas of financing, profitability, capital structure and cash flow.	Multiple Factor – Utility and Non-Utility
Investor Relations Activities	Provide institutional and retail security holder, buy and sell-side analysts, rating agencies, and other key members of the financial community with qualitative and quantitative information.	Multiple Factor – All

BUSINESS DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Mergers and Acquisitions Support	Support, evaluate and assist in the management of merger, asset acquisition and asset disposition activities.	None (All direct charged)
Internal Consulting	Perform strategic analysis/business fit, and economic analysis. Provide integration and transitional management services as needed.	None (All direct charged)

GOVERNMENTAL AFFAIRS

Product or Service	Product / Service Description	Indirect Allocation Methods
Federal Governmental Affairs Support	Activities associated with developing and maintaining relationships with federal government institutions; includes lobbying, and other support activities.	None (All direct charged)
State Governmental Affairs Support	Activities associated with developing and maintaining relationships with state government institutions; includes lobbying, and other support activities.	None (All direct charged)

LEGAL

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Governmental Affairs Support	Activities associated with developing and maintaining relationships with government institutions; includes lobbying, litigation, and other support activities.	None (All direct charged)
Nuclear Legal Consultation and Case Management	Provide legal advice for federal and state nuclear matters.	None (All direct charged)
Human Resources Legal Consultation & Case Management	Provide legal advice for human resource matters (including workers compensation, union negotiations, arbitrations, class action lawsuits, etc.).	Multiple Factor – Utility and Non-Utility

Product or Service	Product / Service Description	Indirect Allocation Methods
Employee Benefits Legal Consultation & Case Management	Provide legal advice for employee benefits matters (including health and welfare benefits, tax-qualified and non-tax qualified benefit plans and programs, pension administration, etc.).	Number of Participating Employees – Utility and Non-Utility
Tax Legal Consultation & Case Management	Provide legal advice for tax matters including federal, state & local tax matters (land tax, sales & use tax, IRS, etc.).	Multiple Factor – All
Bankruptcy Legal Consultation & Case Management	Provide legal advice for bankruptcy matters.	Multiple Factor – Utility and Non-Utility
International Legal Consultation & Case Management	Provide legal advice for international matters– contract negotiations, sale/lease agreements.	None (All direct charged)
Non-Utility Legal Consultation & Case Management	Provide legal advice on federal and state matters to Non-Utility Subsidiaries.	Multiple Factor – Non-Utilities
Regulatory Legal Consultation & Case Management	Provide legal advice for federal and state regulatory matters.	Multiple Factor – Utility
Environmental Legal Consultation & Case Management	Provide legal advice for environmental matters (other than PCB – related matters) - federal (EPA) and state (EPA), regulatory/legislative compliance issues.	None (All direct charged)
PCB Environmental Legal Consultation & Case Management	Provide legal advice for PCB-related matters - federal (EPA) and state (EPA), regulatory/legislative compliance issues.	Multiple Factor – Utility
Real Estate Legal Consultation & Case Management	Provide legal advice for real estate matters.	Multiple Factor – Utility and Non-Utility
Corporate Legal Consultation & Case Management	Provide legal advice for general corporate and transactional matters (including SEC filings, Board of Directors matters, PUHCA, Financings, Securities Matters, Intellectual Property, Technology, General Counsel matters, etc.).	Multiple Factor – All
Claims Legal Consultation & Case Management	Provide legal advice for Claims matters.	Multiple Factor – All

CLAIMS

Product or Service	Product / Service Description	Indirect Allocation Methods

Process Receivable Claims	Provide management, supervision, and performance of tasks associated with the resolution and chargeback of receivable claims.	Multiple Factor - All
Provide Corporate Support	Claims support in evaluating claims, and procuring appropriate external/internal legal resources.	Multiple Factor - All

EXHIBIT JC-16

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

James E. O'Toole

Re: Cash Working Capital

I. INTRODUCTION AND SUMMARY OF TESTIMONY

Q. Please state your name and business address.

A. My name is James E. O'Toole. My business address is 300 Madison Avenue, Morristown, New Jersey.

Q. By whom are you employed and in what capacity?

A. I am employed by FirstEnergy Service Company as an Analyst in the Rates and Regulatory Affairs Department, and primarily support Jersey Central Power & Light Company ("JCP&L"). My experience, education and professional qualifications are set out in Appendix A.

Q. Have you previously testified in Board of Public Utilities ("Board" or "BPU") proceedings?

A. No.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to sponsor the Lead/Lag Study used to determine the cash working capital requirement for JCP&L.

Q. Can you briefly summarize your testimony and conclusions?

A. Yes. Based on the Lead/Lag Study, JCP&L's cash working capital requirement is $114,525,841, as shown on Schedule JOT-1.

II. CASH WORKING CAPITAL

Q. Has the Company included a cash working capital component in the calculation of rate base?

A. Yes, the Company's analysis as described below indicates that inclusion of a cash working capital component in rate base is justified.

Q. Please define cash working capital for ratemaking purposes.

A. Although accountants generally define working capital as a measure of liquidity based on a comparison of current assets to current liabilities, for ratemaking purposes, working capital generally has been defined as the average amount of capital provided by investors, over and above the investment in plant and other specifically identified rate base items, to ensure adequate cash availability between the time expenditures are required to provide service and the time collections are received for that service. For ratemaking purposes, working capital is not a measure of liquidity at a point in time, but the average amount of cash provided by investors on a continuing basis over and above the investment in plant and other specified rate base items.

Q. Why should the Company be allowed to include cash working capital as a component of rate base?

A. Cash working capital is necessary to fund operating costs. The timing difference between the receipt of revenues and the payment of expenses requires that the Company maintain cash working capital to make these payments. If this was not the case, these funds could otherwise be invested in plant or other investments that earn a rate of return.

Q. Has a Lead/Lag Study been prepared for purposes of this case?

A. Yes. The Lead/Lag Study has been prepared by me or under my direct supervision. The results of the Lead/Lag Study are provided in the Schedules attached to my testimony.

Q. Please define the terms "lead" and "lag" with respect to revenue and expenses and explain how each is calculated.

A. In general, a Revenue Lag measures the amount of time that elapses from the provision of a product or service by the Company to a customer and the receipt of the compensation by the Company from the customer for that product or service. A Revenue Lead would be defined as payment to the Company by the customer in advance of the Company providing a product or service to the customer. An Expense Lag would be defined as payment by the Company for a product or service after the Company receives the product or a service has been rendered. An Expense Lead would be defined as payment by the Company for a product or service before the Company receives the product or service. In this study, days were used to quantify the amount of lead or lag time.

Q. Please describe in detail the Lead/Lag Study as filed in this case.

A. The Lead/Lag Study performed for this rate proceeding was calculated using leads and lags developed from a historical analysis of JCP&L's revenues and expenses as reported in JCP&L's FERC Form 1 for the period July 1, 2018 to June 30, 2019 ("Study Period"). The summary of the Lead/Lag Study is shown on Schedule JOT-1. The Lead/Lag Study was broken into two main categories: revenues and expenses. After analyzing the major components of these two main categories, a composite lag factor was developed for the revenue component while a composite lead factor was developed for the expense component. The lag factor for expenses was then subtracted from the lag factor for revenues.

Q. Please describe the methodology used to develop the Revenue Lag for the electric revenue accounts.

A. The electric Revenue Lag consists of three distinct periods: 1) a Service Period Lag, 2) a Meter Reading-to-Billing Lag, and 3) A Billing-to-Payment (Collection) Lag.

The Service Period Lag is measured from the mid-period of the service period to the date a meter is read. The Service Period Lag may be calculated using either billing period or meter reading cycle, both of which are interrelated. Both approaches produce a 15.2 -day Service Period Lag.

The Meter Reading-to-Billing Lag was calculated using the JCP&L Meter Reading Work Schedule for the Study Period. Generally, billing occurs the same day as the meter reading, with the bill mailed the next day. However, exceptions to this generalization are as follows: 1) the billing of the large industrial customers can take an additional day due to the complexity of their bills, and 2) weekends, holidays, and severe weather days require additional time in the reading and/or billing of customers. The meter reading-to-billing lag was calculated to be 1.5 days.

The Company determined the Billing-to-Payment (Collection) Lag using the days sales outstanding method. The days sales outstanding method determines the collection lag by dividing the average accounts receivable balance by the average billed sales per day. The Billing-to-Payment (Collection) Lag using the Study Period data was calculated to be 28.3 days. The details supporting the summary of the lags for the revenue account as presented here is provided on Schedule JOT-3 and summarized on Schedule JOT-2.

Q. How did you calculate the Revenue Lag associated with Other Operating Revenue?

A. The calculation of the Other Operating Revenue Lag is shown on Schedule JOT-4, which lists each of the individual components of Other Operating Revenue and their respective lead or lag. Lag in receipt of Late Payment Charges and Miscellaneous Service Revenues were calculated with overall Electric Revenue Lag because each component is billed with Electric Revenue. The Notes to Schedule JOT-4 explain how leads and lags were calculated for other components of Other Operating Revenue. Total Other Operating Revenue Lag is the dollar-weighted average lag time calculated by dividing total

(Lead)/Lag Dollars (line 11, column 6) by Total Other Operating Revenue in (line 11, column 4).

Q. Please explain the Expense Lag associated with the payment of Energy Purchases.

A. The Expense Lag days associated with Energy Purchases are shown on Schedule JOT-5. This measures the average lag between the Companies' receipt of generation service from suppliers of default generation (i.e., Basic Generation Service or "BGS") until the Companies pay for that service. The period from the midpoint to the end of each monthly service period is 15.2 days (365 days ÷12 months ÷ 2), which assumes uniform purchases over any given service period. The Companies' BGS Supplier Master Agreements require payment on the first business day after the 19th of the month, or twenty days after the end of the service period. The lag is, therefore, 35.2 days (15.2 days + 20 days).

Q. How was the Expense Lag associated with Payroll determined?

A. Payroll is divided into four categories: Bi-weekly Payroll, Weekly Payroll, Payroll-Adjustments, and Incentive Compensation. A weighted average lag time is calculated for each component of payroll, as described in the Notes to Schedule JOT-6. In addition, the total dollar-weighted Payroll lag time is calculated by dividing the total (Lead)/Lag dollars by total Payroll on Schedule JOT-6.

Q. Please identify the components of Employee Benefits and explain how the Expense Lags were calculated for each component.

A. The principal components of Employee Benefits consist of: (1) Medical Insurance; (2) Life Insurance; (3) Savings Plan Match; (4) Worker's Compensation and Long-Term Disability ("LTD") Insurance; and (5) Other Employment Benefits. The Notes to Schedule JOT-7 describe how the lag was calculated for each category. The total dollar-weighted Employee

Benefits Lag is calculated by dividing the total (Lead)/Lag dollars by total Employee Benefits on Schedule JOT-7.

Q. How was the Expense Lag for uncollectible accounts expense determined?

A. The lag for uncollectible accounts is recognized in the calculation of the collection lag as shown on Schedule JOT-8 for Other O&M. The accounts receivable is reduced when uncollectible accounts are written off, and thus reduces the collection lag. To include a lag for uncollectible accounts expense would be double counting.

Q. How did you calculate the Expense Leads and Expense Lags associated with Taxes?

A. A weighted average lead or lag was calculated based on the required payment dates and percentage of the payment due on those dates for each category of tax listed including payroll taxes, on Schedule JOT-9. Additionally, the methodology for computing each weighted average tax lead or lag is detailed in the Notes to Schedule JOT-9.

Q. How were the Expense Lag for depreciation expense determined?

A. In accordance with the decision rendered in the Company's 2012 base rate case (BPU Docket No. ER12111052), depreciation expense has been included with a zero lag as shown on Schedule JOT-1. Depreciation expense represents a return of cash to investors for their investment in plant and should be allowed to earn a return until that cash is returned to the investors. The appropriate way to recognize the return is the inclusion of depreciation in the lead-lag study with a zero-lag.

Q. Has the Company included the provision for deferred income taxes in the Lead/Lag Study?

A. Without conceding potential future positions in regard to this issue, the Company has, in accordance with the decision rendered in its 2012 base rate case (BPU Docket No. ER12111052), not included deferred income taxes in this study.

Q. Were there any major reconciling items between the income statement in the FERC Form 1 and the numbers used for this study?

A. Yes. I have included sales and use tax ("SUT") in both operating revenue and expenses as shown on Schedule JOT-1. In the case of SUT, the Company acts as a collection agent for the State of New Jersey. Customers are billed a charge for SUT, which the Company is responsible for remitting to the State. JCP&L is required to remit these total tax dollars to the State in advance of collecting them from customers, and this timing difference has an impact on the cash working capital requirements of the Company.

Q. What Expense Lag, if any, was assigned for return on invested capital?

A. A zero-lag time was assigned to interest on long-term and short-term debt and dividends on common stock. All the payments for these items originate from operating income, which is the property of the investor once service is provided.

Q. Can you summarize the overall results of your Lead-Lag Study?

A. Yes. As shown on Schedule JOT-1, the study calculated an average lag of 26.1 days, which results in a cash working capital requirement of $114,525,841.

Q. Does this complete your direct testimony in this case?

A. Yes, at this time. I reserve the right to supplement my testimony.

James E. O'Toole

Professional and Educational Background

I am a Regulatory Analyst in the Rates and Regulatory Affairs Department for FirstEnergy Service Company. I have worked in the Rates and Regulatory Affairs Department since September 1990. My position reports directly to the Director of Rates and Regulatory Affairs and I am responsible for providing accounting, financial, and analytical support for various rate activities, particularly for tariff rider filings.

I was first employed by FirstEnergy or its related or predecessor companies ("FE") in November 1987, when I began my employment with Jersey Central Power & Light Company as a Staff Accountant in the General Books group. In that position, I participated in monthly accounting closings, prepared journal entries, performed account analysis and reconciliations and maintained computer-generated reports.

Prior to my employment at FE, I worked as an Accounting Manager at Drakes Bakeries, which was then a subsidiary of Borden, Inc., from January 1983 to October 1987, managing the accounts payable, monthly general ledger closings, budgeting processes, financial statements and doing accounting report writing. From October 1980 to January 1983, I was an Accounting Supervisor at Anchor Savings Bank responsible for monthly general ledger closings, financial statements, account analysis and fixed assets. After graduating from college, I worked as a Junior Accountant with the CPA firm now known as Schonbraun Safris McCann Bekritsky & Co LLC, from July 1979 to September 1980, performing write-ups and bank reconciliations, assisting on audits, and preparing or reviewing payroll, sales, individual and business tax returns.

I am a 1979 graduate of Seton Hall University with a BS in Business Administration and a concentration in Accounting. In 1989, I received my Master of Business Administration with a concentration in Finance from Seton Hall University.

JERSEY CENTRAL POWER & LIGHT COMPANY
2020 Lead/Lag Study
Summary

Line No.	Description	Total Company: 12 Months Ended 6/30/2020 6+6 Forecast	Total Company: Adjustments	Total Company: CWC	Total Company: Lead/ Lags	Total Company: Dollar Days	Transmission Only: CWC	Net of Transmission: CWC	Lead/ Lags	Dollar Days
1	Operating Revenues									
2	Electric Revenues	$ 1,657,712,583		$ 1,657,712,583	45.0	$ 74,597,066,235	$ 75,074,463	$ 1,582,638,120	45.0	$ 71,218,715,400
3	NJ Sales & Use Tax (1)	-	$ 109,823,459	109,823,459	45.0	4,942,055,655	4,973,683	104,849,776	45.0	4,718,239,920
4	Other Revenues	139,556,015		139,556,015	63.4	8,849,926,543	88,268,257	51,287,758	63.4	3,252,406,504
		$ 1,797,268,598	$ 109,823,459	$ 1,907,092,057	46.3	$ 88,389,048,433	$ 168,316,403	$ 1,738,775,654	45.5	$ 79,189,361,824
5	Energy Purchases	$ 901,298,400		$ 901,298,400	35.2	$ 31,725,703,680	$ 173,956	$ 901,124,444	35.2	$ 31,719,580,429
6	BGS/NGC Deferral	2,088,367		2,088,367	0.0	-	-	2,088,367	0.0	-
7	Payroll	177,386,844		177,386,844	23.4	4,142,588,091	10,022,094	167,364,750	23.4	3,908,537,999
8	Employee Benefits	24,849,415		24,849,415	40.9	1,016,767,325	2,142,019	22,707,396	40.9	929,122,005
9	Pension/OPEB	61,750,949		61,750,949	0.0	-	5,322,931	56,428,018	0.0	-
10	Other O&M	214,871,518		214,871,518	26.0	5,593,061,012	22,468,075	192,403,443	26.0	5,008,221,684
11	Operations and Maintenance	$ 1,382,245,492		$ 1,382,245,493	30.7	$ 42,478,120,108	$ 40,129,075	$ 1,342,116,418	31.0	$ 41,565,462,117
11	Depreciation and Amortization	$ 177,475,443	-	$ 177,475,443	0.0	$ -	$ 37,289,183	$ 140,186,260	0.0	$ -
12	Regulatory Debits	62,550,503	-	62,550,503	0.0	-	-	62,550,503	0.0	-
13	Regulatory Credits	(97,478,122)	-	(97,478,122)	0.0	-	-	(97,478,122)	0.0	-
14	Taxes Other Than Income	11,399,506	-	11,399,506	(3.6)	(40,479,897)	1,842,178	9,557,328	(3.6)	(33,938,282)
15	Accretion Expense	9,380,189	-	9,380,189	0.0	-	-	9,380,189	0.0	-
16	Income Taxes									
17	Current	31,767,925	-	31,767,925	35.9	1,141,143,516	-	31,767,925	35.9	1,141,143,516
18	Prior	-	-		0.0	-	-	-	0.0	-
19	Deferred	-	-	-	0.0	-	-	-	0.0	-
20	Investment Tax Credit	-	-	-	0.0	-	-	-	0.0	-
21	NJ Sales Tax	-	109,823,459	109,823,459	(51.5)	(5,655,908,139)	4,973,683	104,849,776	(51.5)	(5,399,763,464)
22	Total Utility Operating Expenses	$ 1,577,340,936	$ 109,823,459	$ 1,687,164,396	22.5	$ 37,922,875,588	$ 84,234,119	$ 1,602,930,277	23.3	$ 37,272,903,887
23	Net Utility Operating Income	$ 219,927,662	$ -	$ 219,927,661	23.9	$ 50,466,172,845	$ 84,082,284	$ 135,845,377	22.3	$ 41,916,457,937
24	Days/Year							366		366
25	Cash Working Capital Requirement	(Total Dollar Days / 366)						$ 4,379,591	26.1	$ 114,525,841

Note
(1) Uses NJ Sales & Use Tax Rate of 6.625%

Jersey Central Power & Light Company
Cash Working Capital
Electric Revenue Lag
For the 12 Months Ended June 30, 2019
$000

Line #		Amount	Lag/ (Lead) Days		Lag/(Lead) Dollars
1	Electric Revenues	$ 1,733,833	45.0	(1)	$ 78,022,485
2	Total Electric Revenues	$ 1,733,833	45.0		$ 78,022,485

(1) Amount from FERC Form 1 (Page 300, Line #10)

Jersey Central Power & Light Company
Cash Working Capital
Revenue Lag (Based On Actuals)
For the 12 Months Ended June 30, 2019
($000)

Line No	Description	Factor	Accounts Receivable Balance	Billed Revenues	A/R Turnover	(Lead) / Lag Days	
	Month / Year:	(1)	(2)	(3)	(4)	(5)	
1	July 2018		$ 157,517	$ 192,302			
2	August 2018		171,443	207,021			
3	September 2018		202,782	209,842			
4	October 2018		151,947	148,960			
5	November 2018		135,934	126,219			
6	December 2018		138,064	143,972			
7	January 2019		153,320	163,741			
8	February 2019		157,237	152,611			
9	March 2019		139,567	142,446			
10	April 2019		115,626	125,168			
11	May 2019		105,619	125,398			
12	June 2019		119,118	141,049			
13	12-month Average Accounts Receivable Balance	=SUM(L1 : L12) / 12	$ 145,681				
14	Total Billed Revenues			$ 1,878,729			
15	Accounts Receivable Turnover (1)	L14 / L13			12.9		
16	Annual Number of Days				365		
17	Collection Days Lag (2)	L16 / L15				28.3	days
18	Lag from Meter Reading to Billing (3)					1.5	days
19	Lag from Service Period to Meter Reading (4)		365 days	/ 12 months /	x 1/2 =	15.2	days
20	Total Revenue Lag					45.0	days

Notes:

Computation of Billing to Cash Collections Lag using Days Sales Outstanding Method:

(1) Average Billed Sales Per Day (ABSD) = $\dfrac{\text{Total Billed Sales}}{\text{Number of Days in a Calendar Year}}$

(2) Days Sales Outstanding (DSO) = $\dfrac{\text{Average Accounts Receivable Balance}}{\text{Average Billed Sales Per Day (ABSD)}}$

(3) Lag based on On-demand billing with additional lag stemming from weekends and holidays.
(4) Lag based on a meter being read 12 times annually and service being rendered evenly throughout the meter reading period.

Exhibit JC-16
Schedule JOT-4

Jersey Central Power & Light Company
Cash Working Capital
Other Operating Revenues
For the 12 Months Ended June 30, 2019
$000

Line #	Other Revenues	Amount	Lag/ (Lead) Days		Lag/(Lead) Dollars
1	Sales for Resale	$ 21,348	35.2	(1)	$ 751,450
2	SREC Sales	10,358	80.0	(2)	828,640
3	Late Payment Charges	2,337	45.0	(3)	105,165
4	Miscellaneous Service Revenues	5,525	45.0	(3)	248,625
5	Telecom Facility Rentals	2,774	70.6	(4)	195,872
6	Telephone/Cable Pole Rentals	5,971	540.8	(4)	3,228,878
7	Intercompany Rentals	213	15.2	(5)	3,238
8	Power Guard Program	879	45.0	(3)	39,555
9	Network Integration Transmission Service (NITS)	79,212	35.2	(1)	2,788,262
10	Other	536	0.0		536
10	Total Other Revenues	$ 129,153	63.4		$ 8,190,221

Notes:
(1) See Note 1 to Schedule JOT-5 for Energy Purchases.
(2) Lag/(Lead) assumes that JCP&L paticipates in four SREC auctions per year and that the SRECs sold in each auction are acquired in the quarter prior to the auction. For example, SRECs sold in Dec.2018 were generated in August 2018 through October 2018.
(3) Lag is the same as the electric revenue lag. See Schedule JOT-2.
(4) Lag/(Lead) based on the weighted average of the largest customers.
(5) Paid monthly on the 20th of the following month. A mid-point of 15.2 days is calculated {(365 ÷ 12) ÷ 2} plus an additional 20 day lag until payment the following month.

Jersey Central Power & Light Company
Cash Working Capital
Energy Purchases
For the 12 Months Ended June 30, 2019
$000

Line #		Amount	Lag/ (Lead) Days		Lag/(Lead) Dollars
1	Energy Purchases	$ 877,343	35.2	(1)	$ 30,882,488

(1) Lag based on service midpoint ((365 ÷ 12) ÷ 2} = 15.2 days) + Supplier Master Agreement payment terms, the first common banking day after the 19th of the month (20 days).

Jersey Central Power & Light Company
Cash Working Capital
Payroll
For the 12 Months Ended June 30, 2019
$000

Line #		Amount	Lag/(Lead) Days		Lag/(Lead) Dollars
1	Bi-weekly Payroll	$ 36,571	11.0	(1)	$ 402,286
2	Weekly Payroll	$ 122,370	7.5	(2)	$ 917,775
3	Other Payroll Adjustments	$ 3,149	8.3	(3)	$ 26,153
4	Incentive Compensation	$ 11,069	242.5	(4)	$ 2,684,342
5	Total Payroll	$ 173,160	23.4		$ 4,043,872

Notes	Description	Payment Weighting Factor	Payment Weighting Ratio	Days Until Payment After Service Period	Midpoint of Service Period	(Lead) / Lag Payment Days	Weighted (Lead) / Lag Days
		(1)	(2)	(3)	(4)	(5) = (3) + (4)	(6) = (5) * (2)
(1)	**BI-WEEKLY PAYROLL (Sunday - Saturday)** -			4.0	7.0	11.0	
(2)	**WEEKLY PAYROLL (Sunday - Saturday)** -			4.0	3.5	7.5	
(3)	**PAYROLL - ADJUSTMENTS** - Weighted on bi-weekly and weekly payroll expense using the total lag days calculated in (a) and (b) above.						
	Bi-weekly Payroll weighted lag days	$ 36,571	23.0%			11.0	2.5
	Weekly Payroll weighted lag days	$ 122,370	77.0%			7.5	5.8
	Total	$ 158,941	100.0%				8.3
(4)	**INCENTIVE COMPENSATION** - Paid for the entire year in early March of the following year; Assume March 1.						
	Payment		100%	60.0	182.5		242.5

Jersey Central Power & Light Company
Cash Working Capital
Employee Benefits
For the 12 Months Ended June 30, 2019
$000

Line #	Description of Benefits	Amount	Lag/(Lead) Days		Lag/(Lead) Dollars
1	Medical Insurance	$ 17,114	42.5	(1)	$ 727,354
2	Life Insurance	$ 1,299	30.2	(2)	$ 39,232
3	Worker's Compensation/LTD	$ 1,180	13.0	(4)	$ 15,340
4	Savings Plan Match	$ 144	13.0	(3)	$ 1,866
5	Other Employee Benefits	$ 5,553	45.2	(5)	$ 250,996
6	Total Employee Benefits	$ 25,290	40.9		$ 1,034,788
7	Pension / OPEB	$ (14,945)	0.0	(6)	$ -

* OPEB is an acronym for Other Post Employment Benefits.

Notes:

(1) Lag based on a typical claim processing time of 1.4 months.

(2) Lag based on premiums being paid on the 15th of the next month for the current month coverage.

(3) See the calculation associated with Note (4) - Payroll Taxes on Schedule JOT-9.
The Savings Plan Match is also made on payday.

(4) Lag based on premiums and claims being paid bi-weekly on a Friday for the prior weeks.

(5) Lag based on Accounts Payable defaulting to a 30 day lag if payment terms are not established + 15.2 midpoint

(6) Lag based on non-cash items being assigned a zero lag.

Jersey Central Power & Light Company
Cash Working Capital
Other O&M
For the 12 Months Ended June 30, 2019
$000

Line #		Amount	Lag/ (Lead) Days		Lag/(Lead) Dollars
1	FE Service Company	$ 118,047	15.2	(1)	$ 1,794,310
2	NJBPU Annual Assessment	$ 4,166	50.0	(2)	$ 208,306
3	Rate Counsel Annual Assessment	$ 996	65.0	(3)	$ 64,748
4	Misc. O&M	$ 69,388	45.0	(4)	$ 3,122,460
5	Uncollectibles	$ 6,783	0.0	(5)	$ -
6	Total Other O&M	$ 199,380	26.0		$ 5,189,823

Notes:

(1) Lag based on midpoint of service period (15.2). Intercompany accounting transactions occur on the last day of the service period. Service Company bills and the Company pays on the same day.

	Description	Payment Percentage	Payment Dates	Midpoint of Service Period	(Lead) / Lag Payment Days	Weighted (Lead) / Lag Days
		(1)	(2)	(3)	(4) = (2) - (3)	(5)
(2)	**NJBPU Annual Assessments**					
	Payment	100%	2/20/19	1/1/19	50.0	50.0

In 2019, assessment was due 2/20, covering the period July 2018 - June 2019. Assumes midpoint of 1/1.

(3)	**RPA Annual Assessments**					
	Payment	100%	3/7/19	1/1/19	65.0	65.0

In 2019, assessment was due 3/7, covering the period July 2018 - June 2019. Assumes midpoint of 1/1.

(4) Lag based on the Company's standard payment terms of 45 days.

(5) Lag days set to zero based on Board decision in New Jersey Natural Gas Company proceeding dated, June 20, 1986, BPU Docket No.GR85100974.

Jersey Central Power & Light Company
Cash Working Capital
Taxes
For the 12 Months Ended June 30, 2019
$000

Line #	Income Taxes:	Amount	Lag/(Lead) Days		Lag/(Lead) Dollars
1	Federal Income Tax	$ (36,512)	37.5	(1)	$ (1,369,184)
2	Corporate Business Tax	$ (697)	-46.8	(2)	$ 32,612
3	Total Income Taxes	$ (37,208)	35.9		$ (1,336,572)
	Taxes Other Than Income Taxes:				
5	Property/Real Estate Taxes	$ 5,170	-14.3	(3)	$ (73,926)
4	Payroll Taxes	$ 4,752	8.3	(4)	$ 39,469
6	Other Taxes	$ (218)	0.0	(5)	$ -
7	Total Taxes	$ 9,704	-3.6		$ (34,458)
8	NJ Sales & Use Tax (NJSUT)	$ 115,592	-51.5	(5) & (6)	$ (5,952,967)

Notes	Line No.	Description	Payment Percentage	Payment Dates	Midpoint of Service Period	(Lead) / Lag Payment Days	Weighted (Lead) / Lag Days
			(1)	(2)	(3)	(4) = (2) - (3)	(5)
(1)		**FEDERAL INCOME TAX**					
	1	First Payment	25%	4/15/19	7/1/19	(77)	(19.3)
	2	Second Payment	25%	6/15/19	7/1/19	(16)	(4.0)
	3	Third Payment	25%	9/15/19	7/1/19	76	19.0
	4	Fourth Payment	25%	12/15/19	7/1/19	167	41.8
	5	Total					37.5
(2)		**CORPORATE BUSINESS TAX**					
	6	First Payment	25%	4/15/19	7/1/19	(77)	(19.3)
	7	Second Payment	50%	5/15/19	7/1/19	(47)	(23.5)
	8	Third Payment	25%	6/15/19	7/1/19	(16)	(4.0)
	9	Total					(46.8)
(3)		**NJ PROPERTY TAX**					
	10	First Payment	25%	2/1/19	7/1/19	(150)	(37.5)
	11	Second Payment	25%	5/1/19	7/1/19	(61)	(15.3)
	12	Third Payment	25%	8/1/19	7/1/19	31	7.8
	13	Fourth Payment	25%	11/1/19	7/1/19	123	30.8
	14	Total					(14.3)
(4)		**PAYROLL TAXES***					
	15	Bi-weekly Payday	$ 36,571	23.0%		11.0	2.5
	16	Weekly Payday	$ 122,370	77.0%		7.5	5.8
	17	Total	$ 158,941	100.0%			8.3
	*	ADP withdraws Tax Expense from the Company's bank account on payday. Weighted on bi-weekly and weekly payroll expense using the paper check lag days calculated in Note 3 on Schedule JOT-6.					
(5)		**NJ SALES TAX**					
	18	First Six Payments	50%	2/20/19	1/15/19	36	18.0
	19	Seventh Payment	50%	5/15/19	10/1/19	(139)	(69.5)
	20	Total					(51.5)