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October 30, 2019

Filed via eTariff

Hon. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: *PJM Interconnection, L.L.C.*
Jersey Central Power & Light Company
Docket No. ER20- -000

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the Regulations of the Federal Energy Regulatory Commission ("FERC" or the "Commission"), 18 C.F.R. pt. 35, Jersey Central Power & Light Company ("JCP&L") hereby requests approval of a change in the revenue requirement used to establish the Network Integration Transmission Service ("NITS") rate charged for the JCPL Zone and the Transmission Enhancement Charge ("TEC") revenue requirements under the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("PJM Tariff") that is set forth in Attachment H-4 of the PJM Tariff.[1] The change in rates will be accomplished by replacing the current, stated revenue requirement in Attachment H-4 with a new transmission formula rate ("Formula Rate") and associated protocols ("Protocols") set forth in Attachments H-4, H-4A, and H-4B of the PJM Tariff. JCP&L, which is

1 Pursuant to Order No. 714, this filing is being submitted by PJM on behalf of JCP&L as part of an XML filing package that conforms with the Commission's regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. Thus, JCP&L has requested that PJM submit this filing in the eTariff system as part of PJM's electronic Intra PJM Tariff.

a FirstEnergy Operating Company, owns transmission facilities in New Jersey subject to the functional control of PJM.

The Formula Rate and Protocols that JCP&L is filing today are just and reasonable and consistent with Commission precedent regarding forward-looking transmission formula rates. JCP&L respectfully requests that the Commission accept the Formula Rate and Protocols effective January 1, 2020. Establishing the requested effective date for this filing will allow JCP&Ls forward-looking formula to take effect as designed on the first day of JCP&L's upcoming rate year.

1. Background

a. FirstEnergy and JCP&L

FirstEnergy Corp. ("FirstEnergy") is a diversified energy company headquartered in Akron, Ohio. FirstEnergy is a holding company under the Public Utility Holding Company Act of 2005 that has both regulated and unregulated subsidiaries and affiliates. FirstEnergy's subsidiaries and affiliates are involved in the transmission and distribution of electricity, as well as energy management and other energy-related services.[2] FirstEnergy Service Company provides legal, financial, and other corporate support services to all of FirstEnergy's subsidiaries and affiliates.

JCP&L is a New Jersey corporation that does business as an electric public utility in New Jersey. JCP&L provides retail electric and distribution services to approximately 1.14 million customers in 3,200 square miles of northern, western, and east-central New Jersey, covering an area with a population of approximately 2.7 million. JCP&L's transmission rates and operations are regulated by the Commission, and its retail and distribution rates and operations are regulated by the New Jersey Board of Public Utilities ("NJBPU"). JCP&L currently owns 2,598 circuit

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2 On March 31, 2018, FirstEnergy's merchant subsidiary, FirstEnergy Solutions Corp. ("FES") filed for Chapter 11 reorganization in federal bankruptcy court. One result of the bankruptcy filing is that an independent board of directors was established for FES and its subsidiaries, and control of all decisions and decision-making of FES transferred to the independent board of directors and the bankruptcy court. Additionally, FES was deconsolidated from FirstEnergy's consolidated financial statements. On October 15, 2019, the Judge overseeing the bankruptcy court proceeding indicated that he intended to confirm the Chapter 11 reorganization plan. As such, FES and its subsidiaries and affiliates that are in the bankruptcy proceeding functionally are independent of FirstEnergy Corp., even if until the end of the bankruptcy proceeding they continue to be affiliates.

miles of transmission lines and related facilities within its service territory under the functional control of PJM.

JCP&L provides open access to its Commission-jurisdictional transmission assets pursuant to the rates, terms, and conditions of the PJM Tariff, and its transmission rates are set forth in attachments to the Tariff. More particularly, the revenue requirements that JCP&L receives for NITS and TEC for use of its transmission assets is presently a Commission-approved "stated" annual revenue requirement which was accepted by the Commission as part of a settlement in 2018. *See PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,140 (2018) (Letter Order approving settlement rate for JCP&L); *see also* PJM Tariff, Attachment H-4 (Annual Transmission Rates – Jersey Central Power & Light Company for Network Integration Transmission Service).

b. JCP&L's Planned Transmission Investments

The Commission has long recognized that transmission formula rates can facilitate capital investments in transmission facilities by reducing the time lag in the recovery of transmission costs, thereby removing a disincentive to "funding necessary transmission infrastructure projects, especially large multi-year capital projects that will relieve congestion and improve reliability." *See Int'l Transmission Co*., 116 FERC ¶ 61,036 at P 19 (2006); *see also Promoting Transmission Inv. Through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 386 (2006) ("We agree with several commenters that formula rates can provide the certainty of recovery that is conducive to large transmission expansion programs [and] we continue to encourage public utilities to explore the benefits of filing transmission-related formula rates."), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g and clarif.*, Order No. 679-B, 119 FERC ¶ 61,062 (2007). Consistent with this policy preference, the forward-looking transmission formula rate proposed in this filing should facilitate transmission investment in the JCP&L zone.

FirstEnergy is currently implementing its Energizing the Future ("EtF") transmission program across its transmission system. EtF is designed to increase the reliability of the FirstEnergy transmission system, improve the condition of equipment, enhance system performance, and improve operational flexibility. The proposed Formula Rate will support this effort by removing regulatory uncertainty with regards to cost recovery for JCP&L's current and future transmission assets.

2. Description of this Filing

JCP&L currently recovers its transmission costs through a stated transmission rate under the PJM Tariff established in a "black box" settlement that was accepted by the Commission in 2018. *PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,140 (2018). With the present filing, JCP&L

seeks to replace this stated rate with the forward-looking Formula Rate, and associated Protocols, as detailed herein.

JCP&L's proposed Formula Rate and Protocols are being filed as Attachments H-4A and Attachment H-4B of the PJM Tariff, respectively. In addition, the Formula Rate and the Protocols are attached to the Prepared Direct Testimony of Roger D. Ruch ("Ruch Testimony") as Exhibit Nos. JCP-102 and JCP-103, respectively.

The Commission has long encouraged transmission owners to use formula rates for recovering transmission costs in order to remove disincentives and encourage transmission expansion programs. *See, e.g.*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 386. Accordingly, the vast majority of FERC-jurisdictional transmission owners in PJM currently recover their transmission costs through formula rates under the PJM Tariff.

The Formula Rate being filed herewith by JCP&L establishes a forward-looking formula rate that recovers projected transmission costs on a calendar year basis, with a true-up (with interest) to ensure that only actual costs are collected. The Formula Rate is similar to multiple other forward-looking transmission formula rates employed by other transmission owners in the PJM region. *See, e.g.*, *PJM Interconnection, L.L.C. and Potomac Elec. Power Co.*, 167 FERC ¶ 61,192 (2019); *PJM Interconnection, L.L.C. and Northeast Transmission Development, LLC*, 155 FERC ¶ 61,097 (2016); *NextEra Energy Transmission West, LLC*, 154 FERC ¶ 61,009 (2015). Further, the Protocols are consistent with the Commission's guidance provided in the Midcontinent Independent System Operator, Inc. ("MISO") proceedings on transmission formula rate protocols, and are based on the forward-looking protocols accepted for filing by the Commission in those proceedings. *See Midwest Indep. Transmission Sys. Operator, Inc*., 139 FERC ¶ 61,127 (2012), *order on investigation*, 143 FERC ¶ 61,149 (2013), *order on reh'g*, 146 FERC ¶ 61,209, *order on compliance filing*, 146 FERC ¶ 61,212 (2014) ("MISO").

JCP&L describes more fully below: (a) the forward-looking formula rate by which JCP&L's Projected Transmission Revenue Requirement ("PTRR") and Actual Transmission Revenue Requirement ("ATRR") will be calculated; (b) the methodologies for allocating certain costs among affiliates; (c) the depreciation rates set forth in the Formula Rate; (d) the fixed return on common equity ("ROE") component of the Formula Rate; (e) the Protocols; and (f) JCP&L's current projections of 2020 costs and special review procedures for those projections.

a. Forward-Looking Formula Rate

JCP&L's proposed Formula Rate is described in the Ruch Testimony and is attached as Exhibit No. JCP-102 thereto in its native Excel format. (Owing to PJM requirements, the formula rate submitted to the Commission's eTariff database is an .rtf file.)

As explained by Mr. Ruch, the proposed Formula Rate forecasts JCP&L's PTRR for the upcoming rate year, which PJM will include in calculating the transmission rates to be effective each rate year beginning on January 1. A true-up between the PTRR and ATRR then will be calculated the following year (rate year plus one) and applied as an addition to or subtraction from the subsequent year's net revenue requirement and resultant rate (rate year plus two). This true-up mechanism ensures that customers are not over charged if the ATRR is less than the billed net revenue requirement. Any difference between the ATRR and PTRR collected during the rate year will be added to or subtracted from the PTRR calculated two years later, with the interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. § 35.19a; or (ii) the interest rate determined by 18 CFR § 35.19a, if JCP&L does not have short-term debt.

As noted, the Formula Rate is similar to multiple other forward-looking formula rates employed by many other transmission owners in the PJM region. *See supra* at 4 (and cases cited therein).

b. Affiliate Cost Allocations

Consistent with Commission precedent, Section VI.A of the Protocols requires that JCP&L include in its annual informational filing a detailed description of the methodologies used to allocate and/or directly assign costs between JCP&L and its affiliates by service category or function; the magnitude of such costs that have been allocated or directly assigned between JCP&L and each affiliate by service category or function; and a copy of any service agreement between JCP&L and any JCP&L affiliate that went into effect during the rate year. *See PJM Interconnection, L.L.C. and Northeast Transmission Development, LLC*, 155 FERC ¶ 61,097 at P 127 (2016), *reh'g denied*, 158 FERC ¶ 61,060 (2017).

In compliance with this requirement, JCP&L is providing a detailed description of its affiliate cost allocation methodologies in the attached testimony of Michael T. Falen, who is Director, Transmission Business Services in the FirstEnergy Utilities Finance Group within the Controller's Group at FirstEnergy Service Company (the "Service Company"). As Mr. Falen explains, JCP&L affiliates will charge JCP&L in accordance with provisions of the FirstEnergy Service Agreement ("Service Agreement"), pursuant to which the Service Company provides administrative services to the FirstEnergy companies including JCP&L, and the Amended and Restated Mutual Assistance Agreement ("Mutual Assistance Agreement"), pursuant to which the FirstEnergy operating companies provide services to each other including JCP&L. The Service Agreement is attached as Exhibit No. JCP-405 and the Mutual Assistance Agreement is attached as Exhibit No. JCP-406. Mr. Falen's testimony regarding cost allocations under the Service Agreement and the Mutual Assistance Agreement is summarized below.

The Service Agreement sets forth the terms under which the Service Company provides centralized administrative, management and other services to FirstEnergy associate companies, including JCP&L. A full list and description of the services provided by the Service Company is provided in Exhibit A to the Service Agreement.

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. 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 billed to that associate company. But where the costs cannot be so identified, they are indirectly charged using the cost allocation methodology set forth in the Service Agreement. (JCP&L emphasizes that the allocation of Service Company costs to FirstEnergy and its associate companies operates independently from, and uses different methodologies than, the allocation of intra-JCP&L costs by operation of the Formula Rate.)

The cost allocation methodologies used by the Service Company presently are set forth in the Service Agreement and are also listed in FERC Form 60, which the Service Company files with the Commission annually. 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. As described in the Service Agreement, the Service Company has eighteen cost allocation methodologies. Seven of the cost allocation methodologies pertain to information technology services. Four others 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 cannot be directly traced to the origin of the costs themselves). The remaining seven cost allocation methodologies are identifiable to particular cost drivers. Such cost allocation methodologies are common in the utility industry.[3]

The Mutual Assistance Agreement is an agreement among the FirstEnergy operating companies pursuant to which they provide non-power goods and services to each other. The Mutual Assistance Agreement requires that all services to JCP&L be provided at cost, and that all goods sold to JCP&L be priced at cost less depreciation. As is the case under the Service Agreement, whenever practicable (to the extent excessive effort or expense is not required), costs

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3 *See, e.g.*, *Financial Accounting, Reporting and Records Retention Requirements Under the Public Utility Holding Company Act of 2005*, Final Rule, Order No. 684, FERC Stats. & Regs. ¶ 31,229 at P 9 (2006) ("[T]he Commission will permit centralized service companies to use a variety of cost accumulation systems, provided such systems support the allocation of expenses to the services performed and readily identify the source of the expenses and the basis for their allocation").

that can be identified as related to a service provided to a company are directly charged to that company.

c. Depreciation Rates

JCP&L is providing as Exhibit No. JCP-300 the testimony of John J. Spanos, President of Gannett Fleming Valuation and Rate Consultants, which describes the development of the depreciation rates set forth in the Formula Rate. Relatedly, the depreciation study produced by Mr. Spanos is attached to his testimony as Exhibit No. JCP-302.

As explained by Mr. Spanos, his depreciation study uses the straight line remaining life method, with the average service life procedure, which is a commonly-used and widely-accepted method for developing utility depreciation rates. The depreciation study is based on Mr. Spanos' analysis of JCP&L's accounting records from 1947 through 2018.

Mr. Spanos further explains that JCP&L is changing the cost of removal approach for developing net salvage values for the transmission-allocated share of general and intangible assets in a way that affects his study to be consistent with how all other transmission assets are treated. Previously, JCP&L expensed the costs of removal as they were incurred. JCP&L is changing this practice, and instead intends to establish a depreciation reserve based on estimated net value percentages and amortizing the cost of removal over the life of the asset. Mr. Spanos explains that the approach he uses for establishing net salvage values is the most commonly used accrual method in the industry.

The results of Mr. Spanos' depreciation analyses are summarized in the table at Pages VI-4 to VI-5 of his depreciation study, Exhibit No. JCP-302 at 47-48.

d. ROE Component

The Formula Rate contains a fixed ROE of 10.8%, based on the analysis and recommendations in the Direct Testimony of Adrien McKenzie, Exhibit No. JCP-200. Mr. McKenzie supports a base ROE of 10.3%, plus a 50 basis point ROE adder for RTO participation, for a total ROE of 10.8%.

Consistent with the Commission's support of the use of multiple financial models to determine ROEs, Mr. McKenzie develops his recommendation for JCP&L's base ROE using four models—the Discounted Cash Flow model, the Empirical Capital Asset Pricing Model, the Expected Earnings approach, and the Risk Premium method. *See Coakley v. Bangor Hydro-Elec. Co.*, Order Directing Briefs, 165 FERC ¶ 61,030 (2018); *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Order Directing Briefs, 165 FERC ¶ 61,118 (2018). Application of the four model methodology results in a composite ROE zone of reasonableness of

7.86% to 13.71%, with median and midpoint values averaging 10.03% and 10.63%, respectively. Mr. McKenzie averages these two values to arrive at his recommended base ROE of 10.3%.

Mr. McKenzie includes a 50 basis point adder to the base ROE for JCP&L's participation in the PJM RTO for a total recommended ROE of 10.8%, which falls within the zone of reasonableness established by Mr. McKenzie. Including an ROE adder of up to 50 basis points for RTO participation is consistent with Commission precedent and the Commission's policy of encouraging utilities to join and remain in RTOs. *See, e.g.*, *Pac. Gas & Elec. Co.*, 168 FERC ¶ 61,038 at PP 1-2 (2019); *Sw. Power Pool, Inc.*, 166 FERC ¶ 61,078 at P 32 (2019) (Mor-Gran-Sou Electric Cooperative, Inc.); *GridLiance Heartland LLC*, 166 FERC ¶ 61,067 at P 1 (2019); *PJM Interconnection, L.L.C. and Northeast Transmission Development, LLC*, 155 FERC ¶ 61,097 at P 94. The Commission has typically allowed public utilities participating in RTOs to include a 50 basis point adder to their base ROE, without setting the issue for hearing. *See, e.g.*, *Sw. Power Pool, Inc.*, 166 FERC ¶ 61,078 at PP 32, 34; *GridLiance Heartland LLC*, 166 FERC ¶ 61,067 at P 1. To JCP&L's knowledge, the ROEs in the transmission formula rates for all FERC-jurisdictional public utilities in PJM currently include a 50 basis point adder for RTO participation. Therefore, consistent with this precedent, and consistent with the Commission's guidance that the 50 basis point adder not cause the ROE to exceed the zone of reasonableness, JCP&L respectfully requests the Commission to approve the 50 basis points adder for RTO participation, without hearing.

e. Formula Rate Protocols

JCP&L also seeks Commission acceptance of the Protocols that govern operation and implementation of the Formula Rate. The Protocols are described in the Ruch Testimony and are attached to the Ruch Testimony as Exhibit No. JCP-103.

As explained by Mr. Ruch, the protocols describe the procedures applicable to the annual update of charges under the Formula Rate and the informational filing of the annual update with the Commission; describe how the annual update will be implemented; and provide a mechanism for parties to review and obtain information about the annual update, and present preliminary and formal challenges to the annual update. In developing the protocols, JCP&L has complied with the Commission's guidance relating to (1) scope of participation; (2) transparency of the information exchange; and (3) the ability of customers to present challenges, which the Commission addressed in its investigation of the formula rate protocols in the MISO tariff. *See MISO*, *supra* note 2. The Protocols are based on the protocols for forward-looking formula rates under the MISO tariff that were developed in the *MISO* proceeding. *See id.*

Consistent with Commission precedent, the Protocols expressly provide that the informational filing and calculation of the ATRR shall include a detailed description of the methodologies used to allocate costs between JCP&L and its affiliates, including any changes to the cost allocation methodologies, the magnitude of allocated costs, and service agreements governing cost allocation. *See, e.g.*, *ATX Sw., LLC*, 161 FERC ¶ 61,049 at P 12 (2017); *NextEra Energy Transmission West, LLC*, 156 FERC ¶ 61,095 at P 10 (2016); *Transource Wis., LLC*, 155 FERC ¶ 61,302 at PP 13-14, *order on reh'g and compliance*, 154 FERC ¶ 61,010 (2016); *PJM Interconnection, L.L.C. and Northeast Transmission Development, LLC*, 155 FERC ¶ 61,097 at P 127.

In the *MISO* proceeding and other recent cases, the Commission has provided guidance to the industry on the appropriate provisions for formula rate protocols. As a result of the Commission's efforts, there has been more consistency in the formula rate protocols being filed by public utilities, and fewer resources expended—by the Commission and the industry—in disputes over the terms of the protocols. In fact, in several recent orders, the Commission has accepted formula rate protocols that generally were consistent with the Commission's guidance without setting those protocols for burdensome hearing and settlement judge procedures, and instead requiring any necessary changes to be made through a compliance filing. *See, e.g.*, *PJM Interconnection, L.L.C. and AMP Transmission, LLC*, 166 FERC ¶ 61,216 at P 33; *NextEra Energy Transmission MidAtlantic, LLC*, 164 FERC ¶ 61,185 at P 23 (2018); *PJM Interconnection, L.L.C. and Northeast Transmission Development, LLC*, 155 FERC ¶ 61,097 at PP 128, 130.

JCP&L respectfully requests that the Commission follow this precedent here. JCP&L has closely adhered to the Commission's guidance in the *MISO* proceeding and other recent cases and is proposing protocols consistent with the Commission's guidance. To the extent the proposed Protocols differ from the protocols approved in the *MISO* proceeding, JCP&L submits there are sound reasons for the differences. For example, whereas the protocols in *MISO* provide for a posting of the projected net revenue requirement on September 1 of each year, it would be impractical for JCP&L to follow such a date. The timing of FirstEnergy's corporate budget process makes it extremely difficult for JCP&L to complete the PTRR any earlier than the end of October. JCP&L is thus proposing a PTRR posting date of October 31 to accommodate this fact.

The proposed Protocols also add two features that were not present in the *MISO* protocols. First, the Protocols add language pertaining to affiliate cost allocation that the Commission deemed necessary in its order in the matter pertaining to Northeast Transmission Development, LLC. *PJM Interconnection, L.L.C. and Northeast Transmission Development, LLC*, 155 FERC ¶ 61,097 at P 127. Second, the Protocols reserve JCP&L's right to make limited, single-issue FPA Section 205 filings to change certain values that are included as stated inputs to the Formula Rate, namely: (i) amortization and depreciation rates; (ii) post-employment benefits other than pensions rates; or (iii) any changes required in a final FERC rulemaking associated with excess/deficient deferred income taxes. The Commission has accepted such single-issue filings in prior cases. *See, e.g.*, *PJM Interconnection, L.L.C. and PPL Elec. Utils. Corp.*, 167 FERC ¶ 61,083 (2019) (single issue filing of ADIT-related changes); *Va. Elec. & Power Co.*, Docket No. ER19-1543-000 (Letter Order issued May 7, 2019) (single issue filing of post-employment benefits other than pension charges); *Sw. Power Pool, Inc.*, 167 FERC ¶ 61,202 (2019) (single issue filing of depreciation rate changes by Mid-Kansas Electric Company, Inc. and Sunflower Electric Power Corporation).

The Commission should, therefore, accept the Protocols without hearing or settlement procedures and, if the Commission finds that the Protocols deviate from Commission policy in any way that necessitates changes, order such changes to the Protocols to be made through a compliance filing.

f. 2020 Projections and Special Review Procedures

As explained above, JCP&L has filed a forward-looking formula rate and has requested an effective date of January 1, 2020. In support of this filing, JCP&L has prepared a projection of its transmission revenue requirement for the calendar year 2020, which JCP&L intends to begin collecting January 1, 2020. JCP&L is providing this projection on an informational basis in Exhibit No. JCP-402, Statement BK for Period II. The projection results in a Network Integration Transmission Service revenue requirement of approximately $147.5 million and a Transmission Enhancement Charge revenue requirement of approximately $22.0 million for 2020. (*See* Exhibit No. JCP-402 at page 45, line 10 and line 7, respectively.)[4] Details regarding the projected costs and rate base are provided in the Ruch Testimony.

For the calendar year 2021 projections, JCP&L will arrange for the projected costs to be posted on the PJM website no later than October 31, 2020. Those projections will be subject to the review and information procedures in the Protocols. Because the Protocols are not yet in effect, JCP&L will use special procedures to ensure that interested parties can review and seek information regarding the 2020 projections before they go into effect on January 1, 2020. Specifically, JCP&L is providing the 2020 projections with this filing, which will be posted on the PJM website. In addition, JCP&L will hold an open meeting to discuss the 2020 projections with interested parties, as it will do under the proposed Protocols for subsequent rate years.

3. Proposed Effective Date

JCP&L respectfully requests that the Commission accept the Formula Rate and Protocols effective January 1, 2020—*i.e.*, sixty-three days after this filing. Granting a January 1, 2020 effective date will allow JCP&L's forward-looking formula rate to take effect as designed on the first day of the upcoming rate year.

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4 A copy of Statement BK (which is the same as the Formula Rate) with 2020 data in Excel format is provided as Exhibit No. JCP-403.

JCP&L respectfully asks the Commission not to impose more than a nominal suspension of this filing that would prevent the requested effective date. Because JCP&L's rates are based on projected costs that will be trued up to actual costs, with interest, the formula rate should not result in unjust and unreasonable and substantially excessive rates under the Commission's *West Texas* policy. *West Tex. Utils. Co*., 18 FERC ¶ 61,189 at 61,374 (1982).[5] Moreover, granting the requested effective date will allow the Formula Rate to take effect on the first day of the calendar year, in accordance with its design. Suspending the Formula Rate beyond this requested date would create significant complications for JCP&L, JCP&L's customers, and the Commission in setting transmission charges for the initial year under the Formula Rate.

The Commission typically has not imposed five-month suspensions of forward-looking transmission formula rates, like the one JCP&L has filed, that are based on calendar year projections and that are trued up to actual costs, with interest. *See, e.g.*, *NorthWestern Corp.*, 167 FERC ¶ 61,278 at PP 1, 99 & n.115 (2019); *PJM Interconnection, L.L.C. and Potomac Elec. Power Co.*, 167 FERC ¶ 61,192 at P 1; *PJM Interconnection, L.L.C. and Northeast Transmission Development, LLC,* 155 FERC ¶ 61,097 at P 2 (2016); *NextEra Energy Transmission, West, LLC*, 154 FERC ¶ 61,009 at P 1 (2016). JCP&L respectfully requests that the Commission not impose a five-month suspension here.

4. Request for Waivers

In transmission formula rate filings, the Commission routinely allows waivers of the requirements of section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13. *See, e.g.*, *San Diego Gas & Elec. Co.*, 165 FERC ¶ 61,276 at P 34 (2018); *Pac. Gas & Elec. Co.*, 165 FERC ¶ 61,194 at P 33 (2018).[6] This is because the statements required by that section typically are not needed where the proposed rates are formulary and will be based on actual costs as reflected in the applicant's audited books and records. However, as explained in the following section, to provide the Commission and the interested parties with information regarding this filing, JCP&L is providing certain of the statements contemplated by section 35.13. To the extent the Commission finds that JCP&L has not fully complied with the requirements of section 35.13, JCP&L respectfully requests waiver of any requirements that are not satisfied by the statements submitted by JCP&L. In addition, JCP&L requests waiver of any other applicable requirement of 18 C.F.R.

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5 *See also Allegheny Power Sys. Operating Cos*., 111 FERC ¶ 61,308 at P 51 (2005) (accepting a proposed transmission formula rate with only a nominal suspension because "the Commission has, in fact, urged transmission owners to move from stated rates to formula rates"), *reh'g denied*, 115 FERC ¶ 61,156 (2006).

6 *See also Tucson Elec. Power Co.*, 168 FERC ¶ 61,068 (2019) (accepting for filing new formula rate that lacked full Section 35.13 statements); *NorthWestern Corp*., 167 FERC ¶ 61,278 (same).

Part 35 for which waiver is not specifically requested in order for the Commission to accept JCP&L's formula rate and protocols, for filing, with an effective date of January 1, 2020.

5. Additional Information Under Section 35.13

In accordance with 18 C.F.R. § 35.13(c), JCP&L is providing information concerning the revenues under the current stated rate for JCP&L and under the proposed Formula Rate submitted in the combined Statement BG/BH and Statement BK for Periods I and II. *See* Exhibit No. JCP-402. In addition, a copy of Statement BK with 2020 data in Excel format is provided as Exhibit No. JCP-403. As explained in Section 4, above, JCP&L requests waiver of the need to provide any additional cost of service statements.

For Period I, JCP&L is using Form 1 data from calendar year 2018. For Period II, JCP&L is using forecast data from calendar year 2020, which is the first twelve-month period following the proposed January 1, 2020 effective date for JCP&L's transmission formula rate. The projections for Period II thus cover the period when the initial charges under the revised Formula Rate are proposed to be in effect.

In addition, an attestation in accordance with 18 C.F.R. § 35.13(d)(6), sponsored by Mr. Falen, provided as Exhibit No. JCP-404.

6. Communications

Please place the following individuals on the official service list for this proceeding.[7]

For JCP&L:

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7 JCP&L respectfully requests waiver of the Commission's regulations, to the extent necessary, so as to permit more than two persons to be placed on the official service list for this docket.

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7. Persons Served

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[8] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[9] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the documents will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

[8] *See* 18 C.F.R. §§ 35.2(e), 385.2010(f)(3).

[9] PJM already maintains, updates and regularly uses e-mail lists for all PJM Members and affected state commissions.

8. Request for Privileged Treatment

JCP&L respectfully requests privileged treatment, in accordance with 18 C.F.R. Section 388.112, for the actuarial study provided as Exhibit No. JCP-104 (part of Attachment 3). This information, which is commercially sensitive and not publicly available, constitutes "[t]rade secrets and commercial or financial information obtained from a person [that are] privileged or confidential."[10] Accordingly, good cause exists for the Commission to grant this request for privileged treatment of this information.

In accordance with 18 C.F.R. Section 388.112(b), enclosed as Attachment 7 is a proposed protective agreement based on the Commission's model protective order.

Any questions regarding this request for privileged treatment should be directed to the undersigned.

9. Contents of Filing

The following documents are included in this filing:

This transmittal letter;

Attachment 1 Marked versions of Attachment H-4 of the PJM Tariff (including the ATRR Statement as Attachment H-4, the Formula Rate as Attachment H-4A, and the Protocols as Attachment H-4B) and a revised Table of Contents for the PJM Tariff;

Attachment 2 Clean versions of Attachment H-4 of the PJM Tariff (including the ATRR Statement as Attachment H-4, the Formula Rate as Attachment H-4A, and the Protocols as Attachment H-4B) and a revised Table of Contents for the PJM Tariff

Attachment 3 Prepared Direct Testimony of Roger D. Ruch and associated Exhibits (Exhibit Nos. JCP-100 to JCP-104) (Portions CUI//PRIV);

Attachment 4 Prepared Direct Testimony of Adrien M. McKenzie and associated Exhibits (Exhibit Nos. JCP-200 to JCP-208);

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10 18 C.F.R. § 388.107(d) & (f).

Attachment 5	Prepared Direct Testimony of John J. Spanos and associated Exhibits (Exhibit Nos. JCP-300 to JCP-302);
Attachment 6	Prepared Direct Testimony of Michael T. Falen and associated Exhibits (Exhibit Nos. JCP-400 to JCP-407); and
Attachment 7	Proposed Protective Agreement.

10. Conclusion

For the reasons stated herein, JCP&L respectfully requests that the Commission accept the Formula Rate and Protocols, without hearing, modification, condition or suspension, effective January 1, 2020.

Respectfully submitted,

/s/ *William S. Scherman*
William S. Scherman
Jeffrey M. Jakubiak
Jennifer C. Mansh

Counsel for FirstEnergy Service Company on behalf of Jersey Central Power & Light Company

Attachments

TABLE OF CONTENTS

ATTACHMENT H-4

Annual Transmission Rates -- Jersey Central Power & Light Company for Network Integration Transmission Service

1. The ~~annual~~ transmission revenue ~~requirement~~requirements and the rates for Network Integration Transmission Service ~~is $135,000,000. Attachment H-4A sets forth the rates for deliveries that utilize Jersey Central Power & Light Company ("JCP&L") distribution facilities at voltages below 34.5 kV delta.~~ are equal to the results of the formula shown in Attachment H- 4A, and will be posted on the PJM website pursuant to Attachment H-4B (Formula Rate Protocols). The transmission revenue requirement ~~reflects~~and the rates reflect the cost of providing transmission service over the 34.5 kV delta and higher transmission facilities of ~~JCP&L.~~Jersey Central Power & Light Company ("JCP&L"). Service utilizing facilities at voltages below 34.5 kV delta will be provided at rates determined on a case-by-case basis and stated in service agreements with affected customers.

2. The formula rate set forth in Attachment H-4A shall be calculated on the basis of projections, subject to true-up to actual data in accordance with the adjustment mechanism described in Attachment H-4B (Formula Rate Protocols).

~~2~~3. The rates and revenue requirements in this attachment shall be effective until amended by JCP&L or modified by the Commission.

~~3~~. In addition to the ~~revenue requirement~~rates set forth in paragraph 1 above, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse JCP&L for applicable sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT H-4A

Annual Transmission Rates ~~Other Supporting Facilities~~ -- Jersey Central Power & Light Company

for Network Integration Transmission Service

Service Below 34.5 kV delta

As provided in Attachment H-4, section 1, service utilizing facilities at voltages below 34.5 kV delta to serve certain New Jersey municipal utilities will be provided at rates determined on a case-by-case basis and stated in existing NITS Agreements under Attachment F through the expiration of such agreements on May 31, 2019. Commencing on June 1, 2019, the rates for such service shall be as follows:

Borough of Butler, New Jersey: $0.1121/kW-Month

Borough of Lavallette, New Jersey: $2.3784/kW-Month

Borough of Madison, New Jersey: $0.0570/kW-Month

Borough of Pemberton, New Jersey: $1.1081/kW-Month

Borough of Seaside Heights, New Jersey: $1.2459/kW-Month

The above rates will be applied to the each of the New Jersey boroughs' monthly sixty (60) minute coincident billing demands measured at the time of JCP&L's system peak each month.

Service Above 34.5 kV delta

See attached formula.

Formula Rate - Non-Levelized — For the 12 months ended 12/31/XXXX

Rate Formula Template
Utilizing FERC Form 1 Data

Jersey Central Power & Light

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 42, col 5]					
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 451	(page 4, line 29)		TP	0.00000	
3	Account No. 454	(page 4, line 30)		TP	0.00000	
4	Account No. 456	(page 4, line 31)		TP	0.00000	
5	Revenues from Grandfathered Interzonal Transactions			TP	0.00000	
6	Revenues from service provided by the ISO at a discount			TP	0.00000	
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12		TP	0.00000	
8	TOTAL REVENUE CREDITS (sum lines 2-7)					
9	True-up Adjustment with Interest	(Attachment 13, Line 28) enter negative				
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)				

					Total
	DIVISOR				
11	1 Coincident Peak (CP) (MW)			(Note A)	
12	Average 12 CPs (MW)			(Note CC)	
			Total		
13	Annual Rate ($/MW/Yr)	(line 10 / line 11)			
			Peak Rate Total		Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)			
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)			
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)			
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)			
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)			

Formula Rate - Non-Levelized | Rate Formula Template | For the 12 months ended 12/31/XXXX

Utilizing FERC Form 1 Data

Jersey Central Power & Light

Line No.	(1) RATE BASE:	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)		NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)		TP	0.00000	
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)		NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)		W/S	0.00000	
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)		CE	0.00000	
6	TOTAL GROSS PLANT (sum lines 1-5)			GP=	0.000%	
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)		NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)		TP	0.00000	
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)		NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)		W/S	0.00000	
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)		CE	0.00000	
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)					
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)				
14	Transmission	(line 2- line 8)		-		
15	Distribution	(line 3 - line 9)				
16	General & Intangible	(line 4 - line 10)				
17	Common	(line 5 - line 11)				
18	TOTAL NET PLANT (sum lines 13-17)			NP=	0.000%	
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 1, Col. 1 (Notes C, F)		NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 1, Col. 2 (Note C, F)		DA	1.00000	
21	Account No. 283 (enter negative)	Attachment 5, Line 1, Col. 3 (Notes C, F)		DA	1.00000	
22	Account No. 190	Attachment 5, Line 1, Col. 4 (Notes C, F)		DA	1.00000	
23	Account No. 255 (enter negative)	Attachment 5, Line 1, Col. 5 (Notes C, F)		DA	1.00000	
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 6, Col. 6 (Notes C & Y)		DA	1.00000	
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 9, Col. 6 (Notes C & Y)		DA	1.00000	
26	CWIP	216.b (Notes X & Z)		DA	1.00000	
27	Unamortized Abandoned Plant	Attachment 16, Line 15, Col. 7 (Notes X & BB)		DA	1.00000	
28	TOTAL ADJUSTMENTS (sum lines 19-27)					
29	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)		TP	0.00000	
30	WORKING CAPITAL (Note H)					
31	CWC	1/8*(Page 3, Line 14 minus Page 3, Line 11)				
32	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)		TE	0.00000	
33	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)		GP	0.00000	
34	TOTAL WORKING CAPITAL (sum lines 31 - 33)					
35	RATE BASE (sum lines 18, 28, 29, & 34)					

Formula Rate - Non-Levelized | Rate Formula Template | For the 12 months ended 12/31/XXXX

Utilizing FERC Form 1 Data

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b		TE	0.00000	
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)			DA	1.00000	
3	Less Account 565	321.96.b		DA	1.00000	
4	Less Account 566	321.97.b		DA	1.00000	
5	A&G	323.197.b		W/S	0.00000	
6	Less FERC Annual Fees			W/S	0.00000	
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)			W/S	0.00000	
8	Plus Transmission Related Reg. Comm. Exp. (Note I)			TE	0.00000	
9	PBOP Expense Adjustment in Year	Attachment 6, Line 11 (Note C)		DA	1.00000	
10	Common	356.1		CE	0.00000	
11	Account 566 Amortization of Regulatory Assets	321.97.b (notes)		DA	1.00000	
12	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 11		DA	1.00000	
13	Total Account 566 (sum lines 11 & 12, ties to 321.97.b)					
14	TOTAL O&M (sum lines 1, 5,8, 9, 10, 13 less 2, 3, 4, 6, 7)					
	DEPRECIATION AND AMORTIZATION EXPENSE					
15	Transmission	336.7.b (Note U)		TP	0.00000	
16	General & Intangible	336.1.f & 336.10.f (Note U)		W/S	0.00000	
17	Common	336.11.b (Note U)		CE	0.00000	
18	Amortization of Abandoned Plant	Attachment 16, Line 15, Col. 5 (Note BB)		DA	1.00000	
19	TOTAL DEPRECIATION (sum lines 15 -18)					
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
20	Payroll	263.i (Attachment 7, line 1z)		W/S	0.00000	
21	Highway and vehicle	263.i (Attachment 7, line 2z)		W/S	0.00000	
22	PLANT RELATED					
23	Property	263.i (Attachment 7, line 3z)		GP	0.00000	
24	Gross Receipts	263.i (Attachment 7, line 4z)		NA		
25	Other	263.i (Attachment 7, line 5z)		GP	0.00000	
26	Payments in lieu of taxes	Attachment 7, line 6z		GP	0.00000	
27	TOTAL OTHER TAXES (sum lines 20 - 26)					
	INCOME TAXES	(Note K)				
28	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
29	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
30	1 / (1 - T) = (from line 29)					
31	Amortized Investment Tax Credit (266.8.f) (enter negative)					
32	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) (Notes D)					
33	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) (Notes E)					
34	Income Tax Calculation = line 29 * line 39			NA		
35	ITC adjustment (line 30 * line 31)			NP	0.00000	
36	Permanent Differences and AFUDC Equity Tax Adjustment (line 30 * line 32)			DA	1.00000	
37	(Excess)/Deficient Deferred Income Tax Adjustment (line 30 * line 33)			DA	1.00000	
38	Total Income Taxes	sum lines 34 through 37				
39	RETURN	[Rate Base (page 2, line 35) * Rate of Return (page 4, line 25, col. 6)]		NA		
40	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)	(sum lines 14, 19, 27, 38, 39)				
41	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)				
42	GROSS REV. REQUIREMENT	(line 40 + line 41)				

Jersey Central Power & Light

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)	
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (page 2, line 2, column 3)							
2	Less transmission plant excluded from ISO rates (Note M)							
3	Less transmission plant included in OATT Ancillary Services (Note N)							
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)							
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=		
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)							
7	Less transmission expenses included in OATT Ancillary Services (Note L)							
8	Included transmission expenses (line 6 less line 7)							
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.00000	
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	0.00000	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.00000	
	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
12	Production	354.20.b	-	0.00	-			
13	Transmission	354.21.b		0.00				
14	Distribution	354.23.b		0.00	-		W&S Allocator	
15	Other	354.24,354.25,354.26. b		0.00	-		($ / Allocation)	
16	Total (sum lines 12-15)					=	0.00000	= WS
	COMMON PLANT ALLOCATOR (CE) (Note O)							
			$		% Electric (line 17 / line 20)		W&S Allocator (line 16, col. 6)	CE
17	Electric	200.3.c	-					
18	Gas	201.3.d	-		0.00000	*	0.00000	= 0.00000
19	Water	201.3.e	-					
20	Total (sum lines 17 - 19)		-					
	RETURN (R)						$	
21	Preferred Dividends (118.29c) (positive number)						-	
			$	%	Cost (Note P)		Weighted	
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)							=WCLTD
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)							
24	Common Stock Attachment 8, Line 14, Col. 6) (Note X)				0.1080			
25	Total (sum lines 22-24)							=R
	REVENUE CREDITS							
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)				
26	a. Bundled Non-RQ Sales for Resale (311.x.h)							
27	b. Bundled Sales for Resale included in Divisor on page 1							
28	Total of (a)-(b)							
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)		(300.17.b)					
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		(300.19.b)					
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)		(330.x.n)					

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT.
B	Prepayments shall exclude prepayments of income taxes.
C	Transmission-related only
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 30).

Inputs Required:	FIT =	0.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA., and related to generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = Attachment 10, Column (j) total. Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by its own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Page 4, Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.

Schedule 1A Rate Calculation

1	$	Attachment H-4A, Page 4, Line 7
2	$	Revenue Credits for Sched 1A - Note A
3	$	Net Schedule 1A Expenses (Line 1 - Line 2)
4		Annual MWh in JCP&L Zone - Note B
5	$	Schedule 1A rate $/MWh (Line 3/ Line 4)

Note:

A Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of JCP&L's zone during the year used to calculate rates under Attachment H-4A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the JCP&L zone. Data from RTO settlement systems for the calendar year prior to the rate year.

Incentive ROE Calculation

For the 12 months ended 12/31/XXXX

Return Calculation

			Source Reference	
1	Rate Base		Attachment H-4A, page 2, Line 35, Col. 5	
2	Preferred Dividends	enter positive	Attachment H-4A, page 4, Line 21, Col. 6	
	Common Stock			
3	Proprietary Capital		Attachment 8, Line 14, Col. 1	
4	Less Preferred Stock		Attachment 8, Line 14, Col. 2	
5	Less Accumulated Other Comprehensive Income Account 219		Attachment 8, Line 14, Col. 4	
6	Less Account 216.1 & Goodwill		Attachment 8, Line 14, Col. 3&5	
7	Common Stock		Attachment 8, Line 14, Col. 6	
	Capitalization			
8	Long Term Debt		Attachment H-4A, page 4, Line 22, Col. 3	
9	Preferred Stock		Attachment H-4A, page 4, Line 23, Col. 3	
10	Common Stock		Attachment H-4A, page 4, Line 24, Col. 3	
11	Total Capitalization		Attachment H-4A, page 4, Line 25, Col. 3	
12	Debt %	Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 4	
13	Preferred %	Preferred Stock	Attachment H-4A, page 4, Line 23, Col. 4	
14	Common %	Common Stock	Attachment H-4A, page 4, Line 24, Col. 4	
15	Debt Cost	Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 5	
16	Preferred Cost	Preferred Stock	Attachment H-4A, page 4, Line 23, Col. 5	
17	Common Cost	Common Stock		0.1080
18	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 12*Line 15)	
19	Weighted Cost of Preferred	Preferred Stock	(Line 13*Line 16)	
20	Weighted Cost of Common	Common Stock	(Line 14*Line 17)	
21	Rate of Return on Rate Base (ROR)		(Sum Lines 18 to 20)	
22	Investment Return = Rate Base * Rate of Return		**(Line 1*Line 21)**	

Income Taxes

	Income Tax Rates		
23	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	Attachment H-4A, page 3, Line 28, Col. 3	
24	CIT=(T/1-T) * (1-(WCLTD/R)) =	Calculated	
25	1 / (1 - T) = (from line 23)	Attachment H-4A, page 3, line 30, Col. 3	
26	Amortized Investment Tax Credit (266.8.f) (enter negative)	Attachment H-4A, page 3, Line 31, Col. 3	
27	Tax Effect of Permanent Differences and AFUDC Equity	Attachment H-4A, page 3, Line 32, Col. 3	
28	(Excess)/Deficient Deferred Income Taxes	Attachment H-4A, page 3, Line 33, Col. 3	
29	Income Tax Calculation	(Line 22*Line 24)	
30	ITC adjustment	Attachment H-4A, page 3, Line 35, Col. 5	
31	Permanent Differences and AFUDC Equity Tax Adjustment	Attachment H-4A, page 3, Line 36, Col. 5	
32	(Excess)/Deficient Deferred Income Tax Adjustment	Attachment H-4A, page 3, Line 37, Col. 5	
33	Total Income Taxes	Sum Lines 29 to 32	

Increased Return and Taxes

34	Return and Income taxes with increase in ROE	(Line 22 + Line 33)	
35	Return without incentive adder	Attachment H-4A, Page 3, Line 39, Col. 5	
36	Income Tax without incentive adder	Attachment H-4A, Page 3, Line 38, Col. 5	
37	Return and Income taxes without increase in ROE	Line 35 + Line 36	
38	Return and Income taxes with increase in ROE	Line 34	
39	Incremental Return and incomes taxes for increase in ROE	Line 38 - Line 37	
40	Rate Base	Line 1	
41	Incremental Return and incomes taxes for increase in ROE divided by rate base	Line 39 / Line 40	

Notes:

Line 17 to include an incentive ROE that is used only to determine the increase in return and incomes taxes associated with a specific increase in ROE. Any actual ROE incentive must be approved by the Commission. Until an ROE incentive is approved, line 17 will reflect the current ROE.

Gross Plant Calculation

For the 12 months ended 12/31/XXXX

			[1] **Production**	[2] **Transmission**	[3] **Distribution**	[4] **Intangible**	[5] **General**	[6] **Common**	[7] **Total**
1	December	20XX							
2	January	20XX							
3	February	20XX							
4	March	20XX							
5	April	20XX							
6	May	20XX							
7	June	20XX							
8	July	20XX							
9	August	20XX							
10	September	20XX							
11	October	20XX							
12	November	20XX							
13	December	20XX							
14	**13-month Average [A] [C]**								

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
			[B]	205.46.g	207.58.g	207.75.g	205.5.g	207.99.g	356.1	
15	December	20XX								
16	January	20XX								
17	February	20XX								
18	March	20XX								
19	April	20XX								
20	May	20XX								
21	June	20XX								
22	July	20XX								
23	August	20XX								
24	September	20XX								
25	October	20XX								
26	November	20XX								
27	December	20XX								
28	13-month Average									

Asset Retirement Costs

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
			[B]	205.44g	207.57.g	207.74.g	company records	207.98.g	company records
29	December	20XX							
30	January	20XX							
31	February	20XX							
32	March	20XX							
33	April	20XX							
34	May	20XX							
35	June	20XX							
36	July	20XX							
37	August	20XX							
38	September	20XX							
39	October	20XX							
40	November	20XX							
41	December	20XX							
42	13-month Average			-					-

Notes:
[A] Taken to Attachment H-4A, page 2, lines 1-6, Col. 3
[B] Reference for December balances as would be reported in FERC Form 1.
[C] Balance excludes Asset Retirements Costs

Accumulated Depreciation Calculation

			[1] Production	[2] Transmission	[3] Distribution	[4] Intangible	[5] General	[6] Common	[7] Total
1	December	20XX							
2	January	20XX							
3	February	20XX							
4	March	20XX							
5	April	20XX							
6	May	20XX							
7	June	20XX							
8	July	20XX							
9	August	20XX							
10	September	20XX							
11	October	20XX							
12	November	20XX							
13	December	20XX							
14	**13-month Average**	**[A] [C]**							

				Production	Transmission	Distribution	Intangible	General	Common	Total
			[B]	219.20-24.c	219.25.c	219.26.c	200.21.c	219.28.c	356.1	
15	December	20XX								
16	January	20XX								
17	February	20XX								
18	March	20XX								
19	April	20XX								
20	May	20XX								
21	June	20XX								
22	July	20XX								
23	August	20XX								
24	September	20XX								
25	October	20XX								
26	November	20XX								
27	December	20XX								
28	13-month Average									

Reserve for Depreciation of Asset Retirement Costs

				Production	Transmission	Distribution	Intangible	General	Common
			[B]	Company Records	Company Records	Company Records	Company Records	Company records	Company Records
29	December	20XX							
30	January	20XX							
31	February	20XX							
32	March	20XX							
33	April	20XX							
34	May	20XX							
35	June	20XX							
36	July	20XX							
37	August	20XX							
38	September	20XX							
39	October	20XX							
40	November	20XX							
41	December	20XX							
42	13-month Average			-		-	-	-	-

Notes:
[A] Taken to Attachment H-4A, page 2, lines 7-11, Col. 3
[B] Reference for December balances as would be reported in FERC Form 1.
[C] Balance excludes reserve for depreciation of asset retirement costs

			[1]	[2]	[3]	[4]	[5]	[6]
			ADIT Transmission Total (including Plant & Labor Related Transmission ADITs and applicable transmission adjustments from notes below)					
			Acct. No. 281 (enter negative)	**Acct. No. 282 (enter negative)**	**Acct. No. 283 (enter negative)**	**Acct. No. 190**	**Acct. No. 255 (enter negative)**	**Total**
				[B]	[C]	[D]	[E]	
1	December 31	20XX	-					

			ADIT Total Transmission-related only, including Plant & Labor Related Transmission ADITs (prior to adjustments from notes below)					
			Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
2	December 31	20XX [G]	-					

Notes:

[A] Beginning/Ending Average with adjustments for FAS143, FAS106, FAS109, CIACs and normalization to populate Appendix H-4A, page 2, lines 19-23, col. 3 for accounts 281, 282, 283, 190, and 255, respectively

[B] FERC Account No. 282 is adjusted for the following items.

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
3	20XX					

[C] FERC Account No. 283 is adjusted for the following items.

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
4	20XX					

[D] FERC Account No. 190 is adjusted for the following items:

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
5	20XX					

[E] See Attachment H-4A, page 5, note K; A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f).

[F] Sourced from Attachment 5b, page 1, col. O for PTRR & Attachment 5C, page 2, col. O for ATRR

[G] Sourced from Attachment 5a, page 1, lines 1-5, col. 4

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line	1	2 Transmission Ending (Note F)	3 End Plant & Labor Related Allocated to Transmission (page 1, col. K)	4 Total Transmission Ending (col. 2 + col. 3) (Note E)
1	ADIT- 282 From Account Subtotal Below			
2	ADIT-283 From Account Subtotal Below			
3	ADIT-190 From Account Subtotal Below			
4	ADIT-281 From Account Subtotal Below			
5	ADIT-255 From Account Subtotal Below			
	Total (sum rows 1-5)			

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line		A End Plant Related (Note A)	B End Labor Related (Note B)	C Plant & Labor Subtotal Col. A + Col. B	D Gross Plant Allocator (Note C)	E Wages & Salary Allocator (Note D)	F End Plant & Labor Related ADIT (Col. A * Col. D) + (Col. B * Col. E)
1	ADIT- 282 From Account Total Below						
2	ADIT-283 From Account Total Below						
3	ADIT-190 From Account Total Below						
4	ADIT-281 From Account Total Below						
5	ADIT-255 From Account Total Below						
6	Subtotal						

Notes
- A From column F (beginning on page 2)
- B From column G (beginning on page 2)
- C Refers to Attachment H-4A, page 2, line 6, col. 4
- D Refers to Attachment H-4A, page 4, line 16, col.6
- E Total Transmission Ending taken to Attachment 5, line 2
- F From column E (beginning on page 2) by account

For the 12 months ended 12/31/XXXX

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-190	End of Year Balance p234.18.c	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Subtotal							

Instructions for Account 190:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-282	**End of Year Balance p275.9.k**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
Subtotal							

Instructions for Account 282:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-283	End of Year Balance p277.19.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Subtotal							

Instructions for Account 283:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-281	End of Year Balance p273.8.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Subtotal							

Instructions for Account 281:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-255	End of Year Balance p267.h	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Subtotal							

Instructions for Account 255:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Line		A	B	C	D	E	F	G	H	I
		20XX Quarterly Activity and Balances								
1	PTRR	Beginning 190 (including adjustments)	Q1 Activity	Ending Q1	Q2 Activity	Ending Q2	Q3 Activity	Ending Q3	Q4 Activity	Ending Q4
2	PTRR	Beginning 190 (including adjustments)	Pro-rated Q1		Pro-rated Q2		Pro-rated Q3		Pro-rated Q4	
3	PTRR	Beginning 282 (including adjustments)	Q1 Activity	Ending Q1	Q2 Activity	Ending Q2	Q3 Activity	Ending Q3	Q4 Activity	Ending Q4
4	PTRR	Beginning 282 (including adjustments)	Pro-rated Q1		Pro-rated Q2		Pro-rated Q3		Pro-rated Q4	
5	PTRR	Beginning 283 (Including adjustments)	Q1 Activity	Ending Q1	Q2 Activity	Ending Q2	Q3 Activity	Ending Q3	Q4 Activity	Ending Q4
6	PTRR	Beginning 283 (Including adjustments)	Pro-rated Q1		Pro-rated Q2		Pro-rated Q3		Pro-rated Q4	

20XX PTRR

Line		Account	J	K	L	M	N	O	P
				Page 1, B+D+F+H	Page 1, row 2,4,6 Column A+B+D+F+H	J-L		M-N	Line 7= J-N-O Lines 8-9= -J+N+O
			Estimated Ending Balance (Before Adjustments)	Projected Activity	Prorated Ending Balance	Prorated – Estimated End (Before Adjustments)	Sum of end ADIT Adjustments	Normalization	Ending ADIT Balance Included in Formula Rate
7	PTRR	Total Account 190							
8	PTRR	Total Account 282							
9	PTRR	Total Account 283							
10	PTRR	Total ADIT Subject to Normalization							

Notes:
1. Attachment 5b will only be populated within the PTRR

Line		A	B	C	D	E	F	G	H	I
		20XX Quarterly Activity and Balances								
		Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
1	PTRR									
2	ATRR									
		Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
3	PTRR									
4	ATRR									
		Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
5	PTRR									
6	ATRR									
		Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
7	PTRR									
8	ATRR									
		Beginning 283 (Including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
9	PTRR									
10	ATRR									
		Beginning 283 (Including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
11	PTRR									
12	ATRR									

20XX PTRR

Line		Account	A Estimated Ending Balance (Before Adjustments)	B Page 1, B+D+F+H Projected Activity	C Page 1, row 3,7,11Column A+B+D+F+H Prorated Ending Balance	D A-C Prorated – Estimated End (Before Adjustments)	E Sum of end ADIT Adjustments	F D-E Normalization	G Line 1= A-E-F Lines 2-3 =A+E+F Ending ADIT Balance Included in Formula Rate
1	PTRR	Total Account 190							
2	PTRR	Total Account 282							
3	PTRR	Total Account 283							
4	PTRR	Total ADIT Subject to Normalization							

20XX ATRR

		Account	H Actual Ending Balance (Before Adjustments)	I Page 1, B+D+F+H Actual Activity	J Page 1, row 4,8,12 column A+B+D+F+H Prorated Ending Balance	K H-J Prorated – Actual End (Before Adjustments)	L D-K Prorated Activity Not Projected	M Sum of end ADIT Adjustments	N E-M ADIT Adjustments not projected	O K+L-M-N Normalization	P Line 5= H-M-O Lines 6-7= -H+M+O Ending ADIT Balance Included in Formula Rate
5	ATRR	Total Account 190									
6	ATRR	Total Account 282									
7	ATRR	Total Account 283									
8	ATRR	Total ADIT Subject to Normalization									

Notes:

Attachment 5c will only be populated within the ATRR

1	**Calculation of PBOP Expenses**		
2	**JCP&L**	**Amount**	**Source**
3	Total FirstEnergy PBOP expenses	-$155,537,000	FirstEnergy 2018 Actuarial Study
4	Labor dollars (FirstEnergy)	$2,363,633,077	FirstEnergy 2018 Actual: Company Records
5	cost per labor dollar (line 3 / line 4)	-$0.0658	
6	labor (labor not capitalized) current year, transmission only		JCP&L Labor: Company Records
7	PBOP Expense for current year (line 5 * line 6)		
8	PBOP expense in Account 926 for current year, total company		JCP&L Account 926: Company Records
9	W&S Labor Allocator		
10	Allocated Transmission PBOP (line 8 * line 9)		
11	PBOP Adjustment for Attachment H-4A, page 3, line 9 (line 7 - line 10)		
12	Lines 3-4 cannot change absent a Section 205 or 206 filing approved or accepted by FERC in a separate proceeding		

For the 12 months ended 12/31/XXXX

Taxes Other than Income Calculation

		[A]	Dec 31, XXXX
1	**Payroll Taxes**		
1a		263.i	
1b		263.i	
1c		263.i	
1d		263.i	
1z	**Payroll Taxes Total**		
2	**Highway and Vehicle Taxes**		
2a		263.i	
2z	**Highway and Vehicle Taxes**		
3	**Property Taxes**		
3a		263.i	
3b		263.i	
3c		263.i	
3d		263.i	
3z	**Property Taxes**		
4	**Gross Receipts Tax**		
4a		263.i	
4z	**Gross Receipts Tax**		
5	**Other Taxes**		
5a		263.i	
5b		263.i	
5c		263.i	
5d			
5z	**Other Taxes**		
6z	**Payments in lieu of taxes**		
7	Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z) [tie to 114.14c]		

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Capital Structure Calculation

				[1] Proprietary Capital	[2] Preferred Stock	[3] Account 216.1	[4] Account 219	[5] Goodwill	[6] Common Stock	[7] Long Term Debt
			[A]	112.16.c	112.3.c	112.12.c	112.15.c	233.5.f	(1) - (2) - (3) - (4) - (5)	112.24.c
1	December	20XX								
2	January	20XX								
3	February	20XX								
4	March	20XX								
5	April	20XX								
6	May	20XX								
7	June	20XX								
8	July	20XX								
9	August	20XX								
10	September	20XX								
11	October	20XX								
12	November	20XX								
13	December	20XX								
14	13-month Average									

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Stated Value Inputs

Formula Rate Protocols
Section VIII.A

1. Rate of Return on Common Equity ("ROE")

JCP&L's stated ROE is set to: 10.8%

2. Postretirement Benefits Other Than Pension ("PBOP")

**sometimes referred to as Other Post Employment Benefits, or "OPEB"*

Total FirstEnergy PBOP expenses	-$155,537,000
Labor dollars (FirstEnergy)	$2,363,633,077
Cost per labor dollar	-$0.0658

3. Depreciation Rates [1][2]

FERC Account	Depr %
350.2	1.53%
352	1.14%
353	2.43%
354	0.83%
355	1.95%
356	2.45%
356.1	1.09%
357	1.39%
358	1.88%
359	1.10%
389.2	3.92%
390.1	1.51%
390.2	0.46%
391.1	4.00%
391.15	5.00%
391.2	20.00%
391.25	20.00%
392	3.84%
393	3.33%
394	4.00%
395	5.00%
396	3.03%
397	5.00%
398	5.00%

Note:

[1] Account 303 amortization period is 7 years.
[2] Accounts 391.10, 391.15, 391.20, 391.25, 393, 394, 395, 397, and 398 have an unrecovered reserve to be amortized over 5 years separately from the assets in these accounts beginning January 1, 2020 through December 31, 2025.

Debt Cost Calculation

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED 12/31/20XX

	t=N	(a) Issue Date	(b) Maturity Date	(c) ORIGINAL ISSUANCE (table 2, col. cc)	(d) Net Proceeds At Issuance (table 2, col. hh)	(e) Net Amount Outstanding at t=N	(f) Months Outstanding at t=N	(g) Average Net Outstanding in Year* z* ((col e. * col. F)/12)	(h) Weighted Outstanding Ratios (col. g/col. g total)	(i) Effective Cost Rate (Table 2, Col. II)	(j) Weighted Debt Cost at t = N (h) * (i)	
Long Term Debt Cost at Year Ended:	**12/31/20XX**											
First Mortgage Bonds:												
(1)												
(2)												
(3)												
(4)												
(5)												
												**

t = time
The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.
The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.
* z = Average of monthly balances for months outstanding during the year (average of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).
Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).
** This Total Weighted Average Debt Cost will be shown on page 4, line 22, column 5 of formula rate Attachment H-4A.

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED 12/31/20XX

	Long Term Debt Issuances	Affiliate	(aa) Issue Date	(bb) Maturity Date	(cc) Amount Issued	(dd) (Discount) Premium at Issuance	(ee) Issuance Expense	(ff) Loss/Gain on Reacquired Debt	(gg) Less Related ADIT	(hh) Net Proceeds (col. cc + col. dd - col. ee - col. ff)	(ii) Net Proceeds Ratio ((col. hh / col. cc) *100)	(jj) Coupon Rate	(kk) Annual Interest (col. cc *col. jj)	(ll) Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
(1)														
(2)														
(3)														
(4)														
(5)														
	TOTALS													

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation
Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_o equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

Transmission Enhancement Charge (TEC) Worksheet

To be completed in conjunction with Attachment H-4A

Line No.	(1)	(2) Reference	(3) Transmission	(4) Allocator
1	Gross Transmission Plant - Total	Attach. H-4A, p. 2, line 2, col. 5 (Note A)		
2	Net Transmission Plant - Total	Attach. H-4A, p. 2, line 14, col. 5 (Note B)		
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-4A, p. 3, line 14, col. 5		
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)		
	GENERAL, INTANGIBLE, AND COMMON (G,I, & C) DEPRECIATION EXPENSE			
5	Total G, I, & C depreciation expense	Attach. H-4A, p. 3, lines 16 & 17, col. 5		
6	Annual allocation factor for G, I, & C depreciation expense	(line 5 divided by line 1, col. 3)		
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach. H-4A, p. 3, line 27, col. 5		
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col. 3)		
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, & 8**		
	INCOME TAXES			
10	Total Income Taxes	Attach. H-4A, p. 3, line 38, col. 5		
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2, col. 3)		
	RETURN			
12	Return on Rate Base	Attach. H-4A, p. 3, line 39, col. 5		
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2, col. 3)		
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		

Columns 5-9 (page 1) only applies with incentive ROE project(s) (Note F)

(5) Line No.	(6)	(7) Reference	(8) Transmission	(9) Allocator
	INCOME TAXES			
10b	Total Income Taxes	Attachment 2, line 33		
11b	Annual Allocation Factor for Income Taxes	(line 10b divided by line 2, col. 3)		
	RETURN			
12b	Return on Rate Base	Attachment 2, line 22		
13b	Annual Allocation Factor for Return on Rate Base	(line 12b divided by line 2, col. 3)		
14b	**Annual Allocation Factor for Return**	**Sum of line 11b and 13b**		
15	**Additional Annual Allocation Factor for Return**	**Line 14 b, col. 9 less line 14, col. 4**		

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-4A

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	**Project Name**	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**Additional Incentive Annual Allocation**	**Total Annual Revenue Requirement**	**True-up Adjustment**	**Net Revenue Requirement**
1			(Note C & H)	(Page 1, line 9)	(Col. 3 * Col. 4)	(Note D & H)	Page 1, line 14	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8, & 9)	(Col. 6 * Page 1, line 15, Col. 9)	(Sum Col. 10 & 11)	(Note G)	(Sum Col. 12 & 13)

3 Transmission Enhancement Credit taken to Attachment H-4A Page 1, Line 7
4 Additional Incentive Revenue taken to Attachment H-4A, Page 3, Line 41

Notes

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-4A.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-4A.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 above. This value includes subsequent capital investments required to maintain the project in-service.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-4A, page 3, line 15.
F Any actual ROE incentive must be approved by the Commission
G True-up adjustment is calculated on the project true-up schedule, attachment 12 column j
H Based on a 13-month average

TEC Worksheet Support
Net Plant Detail

Line No.	Project Name	RTEP Project Number	Project Gross Plant	Dec-XX	Jan-XX	Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sep-XX	Oct-XX	Nov-XX	Dec-XX
			(Note A)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)

NOTE:
[A] Project Gross Plant is the total capital investment for the project, including subsequent capital investments required to maintain the project in-service. Utilizing a 13-month average. [D] Company records

TEC Worksheet Support
Net Plant Detail

Accumulated Depreciation	**Dec-XX**	**Jan-XX**	**Feb-XX**	**Mar-XX**	**Apr-XX**	**May-XX**	**Jun-XX**	**Jul-XX**	**Aug-XX**	**Sep-XX**	**Oct-XX**	**Nov-XX**	**Dec-XX**	**Project Net Plant**
(Note B)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note B & C)

NOTE

[B] Utilizing a 13-month average [C] Taken to Attachment 11, Page 2, Col.6 [D] Company records

For the 12 months ended 12/31/XXXX

TEC – True-up

To be completed after Attachment 11 for the True-up Year is updated using actual data

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	**Project Name**	**RTEP Project Number**	**Actual Revenues for Attachment 11**	**Projected Annual Revenue Requirement**	**% of Total Revenue Requirement**	**Revenue Received**	**Actual Annual Revenue Requirement**	**True-up Adjustment Principal Over/(Under)**	**Applicable Interest Rate on Over/(Under)**	**Total True-up Adjustment with Interest Over/(Under)**
				Projected Attachment 11 p 2 of 2, col. 14	Col d, line 2 / col. d, line 3	Col c, line 1 * Col e	Actual Attachment 11 p 2 of 2, col. 14	Col. f - Col. G	Col. H line 2x / Col. H line 3* Col. J line 4	Col. h + Col. i
1	[A] Actual RTEP Credit Revenues for true-up year		0							
2a	Project 1			-	-	-	-	-		
2b	Project 2				-	-		-		
2c	Project 3				-	-		-		
3	Subtotal			-			-	-		
4	Total Interest (Sourced from Attachment 13a, line 30)									-

NOTE

[A] Amount included in revenues reported on pages 328-330 of FERC Form 1.

Net Revenue Requirement True-up with Interest

	Reconciliation Revenue Requirement For Year 20XX Available June 10, 20XX		20XX Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 20XX		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	**Average Monthly**	**Months**	**Calculated Interest**	**Amortization**	**Surcharge (Refund) Owed**
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.0000%				
	An over or under collection will be recovered prorata over 20XX, held for 20XX and returned prorate over 20XX							
	Calculation of Interest					**Monthly**		
3	January	Year 20XX	-	0.0000%	12	-		-
4	February	Year 20XX	-	0.0000%	11	-		-
5	March	Year 20XX	-	0.0000%	10	-		-
6	April	Year 20XX	-	0.0000%	9	-		-
7	May	Year 20XX	-	0.0000%	8	-		-
8	June	Year 20XX	-	0.0000%	7	-		-
9	July	Year 20XX	-	0.0000%	6	-		-
10	August	Year 20XX	-	0.0000%	5	-		-
11	September	Year 20XX	-	0.0000%	4	-		-
12	October	Year 20XX	-	0.0000%	3	-		-
13	November	Year 20XX	-	0.0000%	2	-		-
14	December	Year 20XX	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 20XX	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
16	January	Year 20XX	-	0.0000%		-	-	-
17	February	Year 20XX	-	0.0000%		-	-	-
18	March	Year 20XX	-	0.0000%		-	-	-
19	April	Year 20XX	-	0.0000%		-	-	-
20	May	Year 20XX	-	0.0000%		-	-	-
21	June	Year 20XX	-	0.0000%		-	-	-
22	July	Year 20XX	-	0.0000%		-	-	-
23	August	Year 20XX	-	0.0000%		-	-	-
24	September	Year 20XX	-	0.0000%		-	-	-
25	October	Year 20XX	-	0.0000%		-	-	-
26	November	Year 20XX	-	0.0000%		-	-	-
27	December	Year 20XX	-	0.0000%		-	-	-
						-		

28	True-Up with Interest	$ -
29	Less Over (Under) Recovery	$ -
30	Total Interest	$ -

[A] Interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if JCP&L does not have short term debt

TEC Revenue Requirement True-up with Interest

	TEC Reconciliation Revenue Requirement For Year 20XX Available June 10, 20XX		TEC 20XX Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 20XX		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	Average Monthly	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.0000%				
	An over or under collection will be recovered prorata over 20XX, held for 20XX and returned prorate over 20XX							
	Calculation of Interest					**Monthly**		
3	January	Year 20XX	-	0.0000%	12	-		-
4	February	Year 20XX	-	0.0000%	11	-		-
5	March	Year 20XX	-	0.0000%	10	-		-
6	April	Year 20XX	-	0.0000%	9	-		-
7	May	Year 20XX	-	0.0000%	8	-		-
8	June	Year 20XX	-	0.0000%	7	-		-
9	July	Year 20XX	-	0.0000%	6	-		-
10	August	Year 20XX	-	0.0000%	5	-		-
11	September	Year 20XX	-	0.0000%	4	-		-
12	October	Year 20XX	-	0.0000%	3	-		-
13	November	Year 20XX	-	0.0000%	2	-		-
14	December	Year 20XX	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 20XX	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
16	January	Year 20XX	-	0.0000%		-	-	-
17	February	Year 20XX	-	0.0000%		-	-	-
18	March	Year 20XX	-	0.0000%		-	-	-
19	April	Year 20XX	-	0.0000%		-	-	-
20	May	Year 20XX	-	0.0000%		-	-	-
21	June	Year 20XX	-	0.0000%		-	-	-
22	July	Year 20XX	-	0.0000%		-	-	-
23	August	Year 20XX	-	0.0000%		-	-	-
24	September	Year 20XX	-	0.0000%		-	-	-
25	October	Year 20XX	-	0.0000%		-	-	-
26	November	Year 20XX	-	0.0000%		-	-	-
27	December	Year 20XX	-	0.0000%		-	-	-
						-		
28	True-Up with Interest						$ -	
29	Less Over (Under) Recovery						$ -	
30	Total Interest						$ -	

[A] Interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if JCP&L does not have short term debt

Other Rate Base Items

				[1]	[2]	[3]	[4]	[5]	[6]
				Land Held for Future Use	**Materials & Supplies**	**Prepayments (Account 165)**		**Total**	
			[A]	214.x.d	227.8.c &.16.c	111.57.c[B]			
1	December 31	20XX		-	-				
2	December 31	20XX		-	-				
3	Begin/End Average			-	-				

				Unfunded Reserve - Plant Related					Total
		FERC Acct No.		**228.1**	**228.2**	**228.3**	**228.4**	**242**	
		[A]	[C]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c	
4	December 31	20XX		-	-	-	-	-	-
5	December 31	20XX		-	-	-	-	-	-
6	Begin/End Average			-	-	-	-	-	-

				Unfunded Reserve - Labor Related						Total
		FERC Acct No.		**228.1**	**228.2**	**228.3**	**228.4**	**242**		
		[A]	[C]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c		
7	December 31	20XX		-	-	-	-	-	-	-
8	December 31	20XX		-	-	-	-	-	-	-
9	Begin/End Average			-	-	-	-	-	-	-

Notes:
[A] Reference for December balances as would be reported in FERC Form 1.
[B] Prepayments shall exclude prepayments of income taxes.
[C] Includes transmission-related balance only

Income Tax Adjustments

	[1]	[2]	[3] Dec 31, 20XX	Reference
1	Tax adjustment for Permanent Differences & AFUDC Equity	[A][C]		JCP&L Company Records
2	Amortized Excess Deferred Taxes (enter negative)	[B][C]		JCP&L Company Records
3	Amortized Deficient Deferred Taxes	[B][C]		JCP&L Company Records

Notes:

[A] AFUDC equity component is the gross cumulative annual amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function.

[B] Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. The balance located within Column 3, row 2 and row 3, is the net impact of excess deferred and deficient amortization.

[C] Year end balance for line 1 taken to Attachment H-4A, page 3, line 32; Year end balance for lines 2-3 taken to Attachment H-4A, page 3, line 33

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Line No.	**Description**	**EDIT Transmission Allocation**	**Amortization Period**	**Years Remaining at Year End**	**Amortization of EDIT**	**Protected (P) Non-Protected (N)**
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30	Total Non-Property Amortization (Total of lines 1 thru 29)					
31	**Property Book-Tax Timing Difference [B] [C]**					N & P
						N & P
32	**Total Non-Property & Property Amortization [A] [B] [C]**					

Notes:

Above amortization is populated from company records

[A] Ties to Attachment 15, page 1, line 2, column 3 for net excess & Attachment 15, page 1, line 3, Column 3 for net deficient

[B] The amortization schedule of the EDIT balance related to Tax Cuts and Job Act of 2017 shall be consistent with the following periods:

Protected Property & Non-Protected Property	ARAM
Non-Protected, Non-Property:	10 years
Protected, Non-Property:	35 years

[C] The regulatory assets and liabilities, included in FERC accounts 182.3 and 254, respectively, will amortize through FERC income statement accounts 410.1 and 411.1

For the 12 months ended 12/31/XXXX

Abandoned Plant

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
2	December 20XX	p111.71.d (and Notes)	13				
3	January	FERC Account 182.2	12				
4	February	FERC Account 182.2	11				
5	March	FERC Account 182.2	10				
6	April	FERC Account 182.2	9				
7	May	FERC Account 182.2	8				
8	June	FERC Account 182.2	7				
9	July	FERC Account 182.2	6				
10	August	FERC Account 182.2	5				
11	September	FERC Account 182.2	4				
12	October	FERC Account 182.2	3				
13	November	FERC Account 182.2	2				
14	December 20XX	p111.71.c (and Notes) Detail on p230b	1				
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13					
					Attachment H-4A, page 3, Line 18		Attachment H-4A, page 2, Line 27

Note:
Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC and will be zero until the Commission accepts or approves recovery of the cost of abandoned plant

			CWIP [A] 216.b	
1	December	20XX		
2	January	20XX		
3	February	20XX		
4	March	20XX		
5	April	20XX		
6	May	20XX		
7	June	20XX		
8	July	20XX		
9	August	20XX		
10	September	20XX		
11	October	20XX		
12	November	20XX		
13	December	20XX		
14	13-month Average			-

Notes:
[A] Includes only CWIP authorized by the Commission for inclusion in rate base.

Federal Income Tax Rate

Nominal Federal Income Tax Rate (entered on Attachment H-4A, page 5 of 5, Note K)	

State Income Tax Rate

	New Jersey	Combined Rate (entered on Attachment H-4A, page 5 of 5, Note K)
Nominal State Income Tax Rate		
Times Apportionment Percentage		
Combined State Income Tax Rate		

Regulatory Asset

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (Company Records)	Additions (Deductions)	Ending Balance
2	December 20XX	p232 (and Notes)	13				
3	January	FERC Account 182.3	12				
4	February	FERC Account 182.3	11				
5	March	FERC Account 182.3	10				
6	April	FERC Account 182.3	9				
7	May	FERC Account 182.3	8				
8	June	FERC Account 182.3	7				
9	July	FERC Account 182.3	6				
10	August	FERC Account 182.3	5				
11	September	FERC Account 182.3	4				
12	October	FERC Account 182.3	3				
13	November	FERC Account 182.3	2				
14	December 20XX	p232 (and Notes)	1				
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13					

Operation and Maintenance Expenses

FF1 Page 321 Line No.	Account Reference	Description	Account Balance [A]
			[redacted]
82		***Operation***	[redacted]
83	560	Operation Supervision and Engineering	
84			[redacted]
85	561.1	Load Dispatch-Reliability	
86	561.2	Load Dispatch-Monitor and Operate Transmission System	
87	561.3	Load-Dispatch-Transmission Service and Scheduling	
88	561.4	Scheduling, System Control and Dispatch Services	
89	561.5	Reliability, Planning and Standards Development	
90	561.6	Transmission Service Studies	
91	561.7	Generation Interconnection Studies	
92	561.8	Reliability, Planning and Standards Development Services	
93	562	Station Expenses	
94	563	Overhead Lines Expense	
95	564	Underground Lines Expense	
96	565	Transmission of Electricity by Others	
97	566	Miscellaneous Transmission Expense	
98	567	Rents	
99		TOTAL Operation (Enter Total of Lines 83 thru 98)	$0
100		***Maintenance***	[redacted]
101	568	Maintenance Supervision and Engineering	
102	569	Maintenance of Structures	
103	569.1	Maintenance of Computer Hardware	
104	569.2	Maintenance of Computer Software	
105	569.3	Maintenance of Communication Equipment	
106	569.4	Maintenance of Miscellaneous Regional Transmission Plant	
107	570	Maintenance of Station Equipment	
108	571	Maintenance of Overhead Lines	
109	572	Maintenance of Underground Lines	
110	573	Maintenance of Miscellaneous Transmission Plant	
111		TOTAL Maintenance (Total of lines 101 thru 110)	$0
112		**TOTAL Transmission Expenses (Total of lines 99 and 111)**	**$0**

Notes:

[A] December balances as would be reported in FERC Form 1

Administrative and General (A&G) Expenses

FF1 Page 323 Line No.	Account Reference	Description	Account Balance [B]
			-
180		***Operation***	-
181	920	Administrative and General Salaries	-
182	921	Office Supplies and Expenses	-
183	Less 922	Administrative Expenses Transferred - Credit	-
184	923	Outside Services Employed	-
185	924	Property Insurance	-
186	925	Injuries and Damages	-
187	926	Employee Pensions and Benefits	-
188	927	Franchise Requirements	-
189	928	Regulatory Commission Expense	-
190	Less 929	(Less) Duplicate Charges-Cr.	-
191	930.1	General Advertising Expenses	-
192	930.2	Miscellaneous General Expenses	-
193	931	Rents	-
194		**Total Operation (Enter Total of lines 181 thru 193)**	$0
195		***Maintenance***	-
196	935	Maintenance of General Plant	-
197		**TOTAL A&G Expenses (Total of lines 194 and 196)**	**$0**

Notes:

[B] December balances as would be reported in FERC Form 1, Transmission only

ATTACHMENT H-4B

~~[Reserved]~~

Jersey Central Power & Light Company

Formula Rate Implementation Protocols

ANNUAL TRUE-UP, INFORMATION EXCHANGE, AND CHALLENGE PROCEDURES

Definitions

"Actual Transmission Revenue Requirement" or "ATRR" means the actual net transmission revenue requirement calculated and posted on the PJM website no later than June 10 of each year subsequent to calendar year 2020 for the immediately preceding calendar year in accordance with JCP&L's Formula Rate and based upon JCP&L's actual costs and expenditures.

"Annual Update" means JCP&L's ATRR for the preceding calendar year, as well as the True-up for the prior Rate Year, as posted on or before June 10 of each year.

"Formal Challenge" means a written challenge to an Annual Update or Projected Transmission Revenue Requirement submitted to the Federal Energy Regulatory Commission (the "Commission" or "FERC") as provided in Section IV below.

"Formula Rate" means the collection of formulas and worksheets, unpopulated with any data, included as Attachment H-4A of the PJM Tariff.

"Interested Parties" include, but are not limited to, customers under the PJM Tariff, state utility regulatory commissions, the Organization of PJM States, Inc., consumer advocacy agencies, and state attorneys general.

"PJM Tariff" means the Open Access Transmission Tariff of the PJM Interconnection, L.L.C.

"Preliminary Challenge" means a written challenge to the Annual Update or Projected Transmission Revenue Requirement submitted to JCP&L as provided in Section IV below.

"Projected Transmission Revenue Requirement" or "PTRR" means the projected net transmission revenue requirement calculated for the forthcoming Rate Year, as well as, where applicable, the most recently calculated True-up, with interest, to be posted on the PJM website no later than October 31 of each year for rates effective the next calendar year starting January 1.

"Protocols" means these Protocols, included as Attachment H-4B of the PJM Tariff).

"Publication Date" means the date on which the Annual Update is posted.

"Rate Year" means the twelve consecutive month period that begins on January 1 and continues through December 31.

"True-up" means the difference between the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) and the ATRR for the same Rate Year, which shall be provided in the Annual Update on or before June 10 of the year subsequent to the Rate Year. The True-up will be a component of the PTRR.

Section I. Applicability

The following procedures shall apply to the Jersey Central Power & Light Company ("JCP&L") calculation of its Actual Transmission Revenue Requirement, True-up, and Projected Transmission Revenue Requirement.

Section II. Annual Update and Projected Transmission Revenue Requirement

A. On or before June 10 of each year subsequent to calendar year 2020, JCP&L shall determine its Annual Update for the immediately preceding calendar year under Attachment H-4A and Section VII of these Protocols, including calculation of the True-up to be included in JCP&L's PTRR for the subsequent Rate Year.

B. On or before June 10 of each year subsequent to calendar year 2020, JCP&L shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website. Within two (2) days of such posting, JCP&L shall provide notice of such posting via an e-mail exploder list.

C. On or before October 31, 2020, and on or before each subsequent October 31, JCP&L shall provide the PTRR to PJM and cause such information to be posted on the PJM website, in both a Portable Document Format ("PDF") and fully-functioning Excel file, and within two (2) days of posting of the PTRR, JCP&L shall provide notice of such posting via an e-mail exploder list.

D. If the date for posting the Annual Update or PTRR falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual Update occurs shall be that year's Publication Date. Any delay in the Publication Date or in the posting of the PTRR will result in an equivalent extension of time for the submission of information requests discussed in Section III of these Protocols.

E. The ATRR shall:

1. Include a workable data-populated version of the Formula Rate template and underlying work papers in Excel format with all formulas and links intact;

2. Be based on JCP&L's FERC Form No. 1 for the prior calendar year;

3. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the ATRR that are not otherwise available in the FERC Form No. 1, subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC's Model Protective Order;

4. Provide sufficient information to enable Interested Parties to replicate the calculation of the ATRR results from the FERC Form No. 1;

5. Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1;

6. Identify and, to the extent not explained in a worksheet included in the ATRR, explain, all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in the FERC Form No. 1;

7. Provide underlying data for Formula Rate inputs that provide greater granularity than is required for the FERC Form No. 1;

8. With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

   a. Identify any Accounting Change, including:

      i. the initial implementation of an accounting standard or policy;

      ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

      iii. correction of errors and prior period adjustments that affect the ATRR and True-up calculation;

      iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the ATRR at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the ATRR; and

d. Provide, for each item identified pursuant to items II.E.8.a - II.E.8.c above, a narrative explanation of the individual impact of such change on the ATRR; and

9. Include for the applicable Rate Year the following information related to affiliate cost allocation: (A) a detailed description of the methodologies used to allocate and directly assign costs between JCP&L and its affiliates by service category and function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; and (B) the magnitude of such costs that have been allocated or directly assigned between JCP&L and each affiliate by service category or function.

F. The Projected Transmission Revenue Requirement shall:

1. Include a workable data-populated version of the Formula Rate template and underlying work papers in Excel format with all formulas and links intact;

2. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the PTRR;

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the PTRR;

4. With respect to any Accounting Change:

a. Identify any Accounting Change, including:

i. the initial implementation of an accounting standard or policy;

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. correction of errors and prior period adjustments that affect the PTRR calculation;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the PTRR at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the PTRR; and

d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these Protocols, a narrative explanation of the individual impact of such change on the PTRR.

G. JCP&L shall hold an open meeting among Interested Parties (“Annual Update Meeting”), to be conducted via Internet webcast, no earlier than ten (10) business days following the Publication Date and no later than July 10. No fewer than seven (7) days prior to such Annual Update Meeting, JCP&L shall provide notice on PJM’s website of the time and date of the Annual Update Meeting, and shall provide notice of the posting via an e-mail exploder list. The Annual Update Meeting shall: (i) permit JCP&L to explain and clarify its ATRR and True-up; and (ii) provide Interested Parties an opportunity to seek information and clarifications from JCP&L about the ATRR and True-up.

H. JCP&L shall hold an open meeting among Interested Parties (“Annual Projected Rate Meeting”), to be conducted via Internet webcast, no earlier than five (5) business days following the posting of the PTRR (as described in Section II.C of these Protocols) and no later than November 30. No fewer than five (5) days prior to such Annual Projected Rate Meeting, JCP&L shall provide notice on PJM’s website of the time and date of the Annual Projected Rate Meeting, and shall provide notice of the posting via an e-mail exploder list. The Annual Projected Rate Meeting shall: (i) permit JCP&L to explain and clarify its PTRR and (ii) provide Interested Parties an opportunity to seek information and clarifications from JCP&L about the PTRR.

Section III. Information Exchange Procedures

Each Annual Update and PTRR shall be subject to the following information exchange procedures (“Information Exchange Procedures”):

A. Interested Parties shall have until January 15 following the Publication Date (unless such period is extended with the written consent of JCP&L or by FERC order) to serve reasonable information and document requests on JCP&L (“Information Exchange

Period”). If January 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

1. the extent or effect of an Accounting Change;
2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these Protocols;
3. the proper application of the Formula Rate and procedures in these Protocols;
4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the ATRR or PTRR;
5. the prudence of actual costs and expenditures;
6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or
7. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

The information and document requests shall not be directed to ascertaining whether the Formula Rate is just and reasonable.

B. JCP&L shall make a good faith effort to respond to any information and document request within fifteen (15) business days of receipt of such request. JCP&L shall respond to all information and document requests by no later than February 25 following the Publication Date, unless the Information Exchange Period is extended by JCP&L or FERC.

C. JCP&L will serve all information requests from Interested Parties and JCP&L’s response(s) to such requests upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such information requests or responses, as needed, under non-disclosure agreements that are based on FERC’s Model Protective Order.

D. JCP&L shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any proceeding addressing JCP&L’s Annual Update or PTRR, and such responses may be included in any Formal Challenge or other submittal addressing JCP&L’s Annual Update or PTRR.

Section IV. Challenge Procedures

A. Interested Parties shall have until March 31 following the Publication Date (unless such period is extended with the written consent of JCP&L or by FERC order) ("Review Period"), to review the inputs, supporting explanations, allocations and calculations and to notify JCP&L in writing, which may be made electronically, of any specific Preliminary Challenges to the Annual Update or PTRR. If the final day of the Review Period falls on a holiday recognized by FERC, the deadline for submitting all Preliminary Challenges shall be extended to the next business day. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update or PTRR shall bar pursuit of such issue with respect to that Annual Update or PTRR under the challenge procedures set forth in these Protocols, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update or PTRR. This Section IV.A in no way shall affect a party's rights under Federal Power Act ("FPA") section 206 as set forth in Section IV.I of these Protocols.

B. Preliminary Challenges shall be subject to the resolution procedures and limitations in this Section IV and shall satisfy all of the following requirements.

1. A party submitting a Preliminary Challenge to JCP&L must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge.

2. JCP&L shall make a good faith effort to respond to any Preliminary Challenge within twenty (20) business days of written receipt of such challenge.

3. JCP&L, and where applicable, PJM, shall appoint a senior representative to work with each party that submitted a Preliminary Challenge (or its representative) toward a resolution of the challenge.

4. If JCP&L disagrees with such challenge, JCP&L will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information.

5. No Preliminary Challenge may be submitted after March 31, and JCP&L must respond to all Preliminary Challenges by no later than April 30 unless the Review Period is extended by JCP&L or FERC, or as provided in Section IV.A above.

6. JCP&L will serve all Preliminary Challenges and JCP&L's response(s) to such Preliminary Challenges upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such Preliminary Challenges or responses, as needed, under non-disclosure agreements that are based on the FERC's Model Protective Order.

C. Formal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy all of the following requirements.

1. A Formal Challenge shall:

a. Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or these Protocols;

b. Explain how the action or inaction violates the filed Formula Rate or these Protocols;

c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

(i) the extent or effect of an Accounting Change;

(ii) whether the ATRR or PTRR fails to include data properly recorded in accordance with these Protocols;

(iii) the proper application of the Formula Rate and procedures in these Protocols;

(iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the ATRR or PTRR;

(v) the prudence of actual costs and expenditures;

(vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

(vii) any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the challenged action or inaction;

e. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the challenged action or inaction raised by the Formal Challenge, and, if not, describe why not.

2. Service. Any person filing a Formal Challenge must serve a copy of such Formal Challenge on JCP&L. Service to JCP&L must be simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. A party filing a Formal Challenge shall serve the individual listed as the contact person on JCP&L's Informational Filing required under Section VI of these Protocols.

D. Preliminary and Formal Challenges shall be limited to all issues that may be necessary to determine:

1. the extent or effect of an Accounting Change;

2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these Protocols, or includes data not properly recorded in accordance with these Protocols;

3. the proper application of the Formula Rate and procedures in these Protocols;

4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the ATRR and PTRR;

5. the prudence of actual costs and expenditures included as inputs to the Formula Rate;

6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

7. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

E. Any changes or adjustments to the ATRR and PTRR resulting from the information exchange and Preliminary Challenge processes that are agreed to by JCP&L will be reported in the Informational Filing required pursuant to Section VI of these Protocols. Any such changes or adjustments agreed to by JCP&L on or before December 1 will be reflected in the PTRR for the upcoming Rate Year. Any changes or adjustments agreed to by JCP&L after December 1 will be reflected in the following year's Annual Update, as discussed in Section V of these Protocols.

F. An Interested Party shall have until June 1 following the Review Period (unless such date is extended with the written consent of JCP&L to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with FERC, which shall be served on JCP&L on the date of such filing as specified in Section IV.C.2 above. A Formal Challenge shall be filed in the same docket as JCP&L's Informational Filing discussed in Section VI of these Protocols. JCP&L shall respond to the Formal Challenge by the deadline established by FERC. An Interested Party may not pursue a Formal Challenge unless it submitted a Preliminary Challenge on some issue (which may be different from the Formal Challenge issue) during the applicable Review Period.

G. In any proceeding initiated by FERC concerning the Annual Update or PTRR or in response to a Formal Challenge, JCP&L shall bear the burden, consistent with FPA section 205, of proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols, that it followed the applicable requirements and procedures in the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

H. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of JCP&L to file unilaterally, pursuant to FPA section 205 and the regulations thereunder, to change these Protocols, the Formula Rate, or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to FPA section 206.

I. No party shall seek to modify these Protocols or the Formula Rate under the challenge procedures set forth in these Protocols, and the Annual Update and PTRR shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to these Protocols or the Formula Rate will require, as applicable, a FPA section 205 or section 206 proceeding. JCP&L may, at its discretion and at a time of its choosing, make a limited filing pursuant to FPA section 205 to modify stated values in the Formula Rate for (a) amortization and depreciation rates, (b) Post-Employment Benefits Other Than Pensions rates, or (c) to make any changes required in a final FERC rulemaking associated with excess/deficient deferred income taxes. The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.

J. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1 shall first raise the matter with JCP&L in accordance with this Section IV before pursuing a Formal Challenge.

Section V. Changes to Actual Transmission Revenue Requirement or Projected Transmission Revenue Requirement

A. Except as provided in Section IV.E of these Protocols, any changes to the data inputs, including but not limited to revisions to JCP&L's FERC Form No. 1, or as the result of any FERC proceeding to consider the ATRR or PTRR, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the PTRR for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these Protocols.

Section VI. Informational Filings

A. By June 10 of each year, JCP&L shall submit to FERC an informational filing ("Informational Filing") of its PTRR for the Rate Year, including its ATRR and True-up. This Informational Filing must include information that is reasonably necessary to determine:

1. that input data to the Formula Rate are properly recorded in any underlying work papers;
2. that JCP&L has properly applied the Formula Rate and these Protocols;
3. the accuracy of data and the consistency with the Formula Rate of the transmission revenue requirement and rates under review;
4. the extent of Accounting Changes that affect Formula Rate inputs; and
5. the reasonableness of projected costs.

The Informational Filing must also describe any corrections or adjustments made during the period since the Publication Date, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Preliminary Challenge or Formal Challenge procedures.

Finally, the Informational Filing shall include for the applicable Rate Year the following information related to affiliate cost allocation: a detailed description of the methodologies used to allocate and directly assign costs between JCP&L and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; the magnitude of such costs that have been allocated or directly assigned between JCP&L and each affiliate by service category or function; and a copy of any service agreement between JCP&L and any JCP&L affiliate that went into effect during the Rate Year.

Within five (5) days of such Informational Filing, JCP&L shall provide notice of the Informational Filing via an e-mail exploder list and by posting the docket number assigned to JCP&L's Informational Filing on the PJM website, subject to the protection of any confidential information contained in the Informational Filing, as needed, under nondisclosure agreements that are based on FERC's Model Protective Order.

B. Any challenges to the implementation of the Formula Rate must be made through the challenge procedures described in Section IV of these Protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

Section VII. Calculation of True-up

The True-up will be determined in the following manner:

A. As part of the Annual Update for each Rate Year, JCP&L shall determine the difference between the revenues collected by PJM based on the PTRR for the Rate Year (net of the True-up from the prior year) and the ATRR for the same Rate Year based on actual cost data as reflected in its FERC Form No. 1. The True-up will be determined as follows:

   i. The ATRR for the previous Rate Year as determined using JCP&L's completed FERC Form No. 1 report shall be compared to the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) for that same Rate Year ("True-up Year") to determine any excess or shortfall in the revenues collected by PJM in the True-up Year. The revenue excess or shortfall determined by this comparison shall constitute the "True-up."

   ii. Interest on any True-up shall be based on the interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. § 35.19a; or (ii) the interest rate determined by 18 CFR § 35.19a, if JCP&L does not have short-term debt. Interest rates will be used to calculate the time value of money for the period that the True-up exists. The interest rate to be applied to the True-up will be determined using the average rate for the twenty (20) months preceding September 1 of the current year.

B. JCP&L will post on PJM's website all information relating to the True-up as part of the Annual Update. As provided in Section II.B of these Protocols, JCP&L shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website on or before June 10 of each year subsequent to calendar year 2020.

Section VIII. Formula Rate Inputs

A. Stated inputs to the Formula Rate: For (i) rate of return on common equity; (ii) "Post-Employment Benefits other than Pension" ("PBOP") charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement

Benefits Other Than Pensions; and (iii) depreciation and/or amortization rates, the values in the Formula Rate shall be stated values and may be changed only pursuant to a FPA section 205 or section 206 proceeding. These stated-value inputs are specified in Attachment 9 of the Formula Rate.

B. Unpopulated Formula Rate line items: With respect to line items in the Formula Rate that are not currently populated with non-zero numerical values because FERC policy requires prior authorization for recovery of the underlying costs or because, due to the nature of the associated functional activities, such costs are not considered part of JCP&L's transmission-related revenue requirement (but not line items that are zero values in a particular Rate Year for the sole reason that no such costs or revenues were incurred or revenues received or projected to be incurred or received during the Rate Year), such line items shall not be populated with non-zero values except as may be authorized following a FPA section 205 or section 206 proceeding.

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ATTACHMENT H-4

Annual Transmission Rates -- Jersey Central Power & Light Company for Network Integration Transmission Service

1. The transmission revenue requirements and the rates for Network Integration Transmission Service are equal to the results of the formula shown in Attachment H- 4A, and will be posted on the PJM website pursuant to Attachment H-4B (Formula Rate Protocols). The transmission revenue requirement and the rates reflect the cost of providing transmission service over the 34.5 kV delta and higher transmission facilities of Jersey Central Power & Light Company ("JCP&L"). Service utilizing facilities at voltages below 34.5 kV delta will be provided at rates determined on a case-by-case basis and stated in service agreements with affected customers.

2. The formula rate set forth in Attachment H-4A shall be calculated on the basis of projections, subject to true-up to actual data in accordance with the adjustment mechanism described in Attachment H-4B (Formula Rate Protocols).

3. The rates and revenue requirements in this attachment shall be effective until amended by JCP&L or modified by the Commission.

. In addition to the rates set forth in paragraph 1 above, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse JCP&L for applicable sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT H-4A
Annual Transmission Rates -- Jersey Central Power & Light Company
for Network Integration Transmission Service

<u>Service Below 34.5 kV delta</u>

As provided in Attachment H-4, section 1, service utilizing facilities at voltages below 34.5 kV delta to serve certain New Jersey municipal utilities will be provided at rates determined on a case-by-case basis and stated in existing NITS Agreements under Attachment F through the expiration of such agreements on May 31, 2019. Commencing on June 1, 2019, the rates for such service shall be as follows:

Borough of Butler, New Jersey: $0.1121/kW-Month

Borough of Lavallette, New Jersey: $2.3784/kW-Month

Borough of Madison, New Jersey: $0.0570/kW-Month

Borough of Pemberton, New Jersey: $1.1081/kW-Month

Borough of Seaside Heights, New Jersey: $1.2459/kW-Month

The above rates will be applied to the each of the New Jersey boroughs' monthly sixty (60) minute coincident billing demands measured at the time of JCP&L's system peak each month.

<u>Service Above 34.5 kV delta</u>

See attached formula.

Formula Rate - Non-Levelized

For the 12 months ended 12/31/XXXX

Rate Formula Template
Utilizing FERC Form 1 Data

Jersey Central Power & Light

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 42, col 5]					
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 451	(page 4, line 29)		TP	0.00000	
3	Account No. 454	(page 4, line 30)		TP	0.00000	
4	Account No. 456	(page 4, line 31)		TP	0.00000	
5	Revenues from Grandfathered Interzonal Transactions			TP	0.00000	
6	Revenues from service provided by the ISO at a discount			TP	0.00000	
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12		TP	0.00000	
8	TOTAL REVENUE CREDITS (sum lines 2-7)					
9	True-up Adjustment with Interest	(Attachment 13, Line 28) enter negative				
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)				
	DIVISOR					Total
11	1 Coincident Peak (CP) (MW)				(Note A)	
12	Average 12 CPs (MW)				(Note CC)	
			Total			
13	Annual Rate ($/MW/Yr)	(line 10 / line 11)				
			Peak Rate Total			Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)				
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)				
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)				
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)				
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)				

Formula Rate - Non-Levelized | Rate Formula Template | For the 12 months ended 12/31/XXXX

Utilizing FERC Form 1 Data

Jersey Central Power & Light

Line No.	(1) RATE BASE:	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)		NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)		TP	0.00000	
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)		NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)		W/S	0.00000	
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)		CE	0.00000	
6	TOTAL GROSS PLANT (sum lines 1-5)			GP=	0.000%	
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)		NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)		TP	0.00000	
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)		NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)		W/S	0.00000	
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)		CE	0.00000	
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)					
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)				
14	Transmission	(line 2- line 8)		-		
15	Distribution	(line 3 - line 9)				
16	General & Intangible	(line 4 - line 10)				
17	Common	(line 5 - line 11)				
18	TOTAL NET PLANT (sum lines 13-17)			NP=	0.000%	
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 1, Col. 1 (Notes C, F)		NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 1, Col. 2 (Note C, F)		DA	1.00000	
21	Account No. 283 (enter negative)	Attachment 5, Line 1, Col. 3 (Notes C, F)		DA	1.00000	
22	Account No. 190	Attachment 5, Line 1, Col. 4 (Notes C, F)		DA	1.00000	
23	Account No. 255 (enter negative)	Attachment 5, Line 1, Col. 5 (Notes C, F)		DA	1.00000	
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 6, Col. 6 (Notes C & Y)		DA	1.00000	
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 9, Col. 6 (Notes C & Y)		DA	1.00000	
26	CWIP	216.b (Notes X & Z)		DA	1.00000	
27	Unamortized Abandoned Plant	Attachment 16, Line 15, Col. 7 (Notes X & BB)		DA	1.00000	
28	TOTAL ADJUSTMENTS (sum lines 19-27)					
29	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)		TP	0.00000	
30	WORKING CAPITAL (Note H)					
31	CWC	1/8*(Page 3, Line 14 minus Page 3, Line 11)				
32	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)		TE	0.00000	
33	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)		GP	0.00000	
34	TOTAL WORKING CAPITAL (sum lines 31 - 33)					
35	RATE BASE (sum lines 18, 28, 29, & 34)					

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/XXXX

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b		TE	0.00000	
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)			DA	1.00000	
3	Less Account 565	321.96.b		DA	1.00000	
4	Less Account 566	321.97.b		DA	1.00000	
5	A&G	323.197.b		W/S	0.00000	
6	Less FERC Annual Fees			W/S	0.00000	
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)			W/S	0.00000	
8	Plus Transmission Related Reg. Comm. Exp. (Note I)			TE	0.00000	
9	PBOP Expense Adjustment in Year	Attachment 6, Line 11 (Note C)		DA	1.00000	
10	Common	356.1		CE	0.00000	
11	Account 566 Amortization of Regulatory Assets	321.97.b (notes)		DA	1.00000	
12	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset) 321.97.b - line 11			DA	1.00000	
13	Total Account 566 (sum lines 11 & 12, ties to 321.97.b)					
14	TOTAL O&M (sum lines 1, 5,8, 9, 10, 13 less 2, 3, 4, 6, 7)					
	DEPRECIATION AND AMORTIZATION EXPENSE					
15	Transmission	336.7.b (Note U)		TP	0.00000	
16	General & Intangible	336.1.f & 336.10.f (Note U)		W/S	0.00000	
17	Common	336.11.b (Note U)		CE	0.00000	
18	Amortization of Abandoned Plant	Attachment 16, Line 15, Col. 5 (Note BB)		DA	1.00000	
19	TOTAL DEPRECIATION (sum lines 15 -18)					
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
20	Payroll	263.i (Attachment 7, line 1z)		W/S	0.00000	
21	Highway and vehicle	263.i (Attachment 7, line 2z)		W/S	0.00000	
22	PLANT RELATED					
23	Property	263.i (Attachment 7, line 3z)		GP	0.00000	
24	Gross Receipts	263.i (Attachment 7, line 4z)		NA		
25	Other	263.i (Attachment 7, line 5z)		GP	0.00000	
26	Payments in lieu of taxes	Attachment 7, line 6z		GP	0.00000	
27	TOTAL OTHER TAXES (sum lines 20 - 26)					
	INCOME TAXES	(Note K)				
28	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
29	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
30	1 / (1 - T) = (from line 29)					
31	Amortized Investment Tax Credit (266.8.f) (enter negative)					
32	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) (Notes D)					
33	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) (Notes E)					
34	Income Tax Calculation = line 29 * line 39			NA		
35	ITC adjustment (line 30 * line 31)			NP	0.00000	
36	Permanent Differences and AFUDC Equity Tax Adjustment (line 30 * line 32)			DA	1.00000	
37	(Excess)/Deficient Deferred Income Tax Adjustment (line 30 * line 33)			DA	1.00000	
38	Total Income Taxes	sum lines 34 through 37				
39	RETURN	[Rate Base (page 2, line 35) * Rate of Return (page 4, line 25, col. 6)]		NA		
40	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)	(sum lines 14, 19, 27, 38, 39)				
41	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)				
42	GROSS REV. REQUIREMENT	(line 40 + line 41)				

Formula Rate - Non-Levelized | Rate Formula Template | For the 12 months ended 12/31/XXXX

Utilizing FERC Form 1 Data

Jersey Central Power & Light

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)	
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (page 2, line 2, column 3)							
2	Less transmission plant excluded from ISO rates (Note M)							
3	Less transmission plant included in OATT Ancillary Services (Note N)							
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)							
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=		
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)							
7	Less transmission expenses included in OATT Ancillary Services (Note L)							
8	Included transmission expenses (line 6 less line 7)							
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.00000	
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	0.00000	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.00000	
	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
12	Production	354.20.b	-	0.00	-			
13	Transmission	354.21.b		0.00				
14	Distribution	354.23.b		0.00	-		W&S Allocator	
15	Other	354.24,354.25,354.26. b		0.00	-		($ / Allocation)	
16	Total (sum lines 12-15)					=	0.00000	= WS
	COMMON PLANT ALLOCATOR (CE) (Note O)							
			$		% Electric		W&S Allocator	
17	Electric	200.3.c	-		(line 17 / line 20)		(line 16, col. 6)	CE
18	Gas	201.3.d	-		0.00000	*	0.00000	= 0.00000
19	Water	201.3.e	-					
20	Total (sum lines 17 - 19)		-					
	RETURN (R)						$	
21	Preferred Dividends (118.29c) (positive number)						-	
			$	%	Cost (Note P)		Weighted	
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)							=WCLTD
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)							
24	Common Stock Attachment 8, Line 14, Col. 6) (Note X)				0.1080			
25	Total (sum lines 22-24)							=R
	REVENUE CREDITS							
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)				
26	a. Bundled Non-RQ Sales for Resale (311.x.h)							
27	b. Bundled Sales for Resale included in Divisor on page 1							
28	Total of (a)-(b)							
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)		(300.17.b)					
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		(300.19.b)					
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)		(330.x.n)					

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT.
B	Prepayments shall exclude prepayments of income taxes.
C	Transmission-related only
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 30).

Inputs Required:	FIT =	0.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA., and related to generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = Attachment 10, Column (j) total. Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by its own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Page 4, Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.

For the 12 months ended 12/31/XXXX

Schedule 1A Rate Calculation

1	$	Attachment H-4A, Page 4, Line 7
2	$	Revenue Credits for Sched 1A - Note A
3	$	Net Schedule 1A Expenses (Line 1 - Line 2)
4		Annual MWh in JCP&L Zone - Note B
5	$	Schedule 1A rate $/MWh (Line 3/ Line 4)

Note:

A Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of JCP&L's zone during the year used to calculate rates under Attachment H-4A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the JCP&L zone. Data from RTO settlement systems for the calendar year prior to the rate year.

Incentive ROE Calculation

For the 12 months ended 12/31/XXXX

Return Calculation

			Source Reference	
1	Rate Base		Attachment H-4A, page 2, Line 35, Col. 5	
2	Preferred Dividends	enter positive	Attachment H-4A, page 4, Line 21, Col. 6	
	Common Stock			
3	Proprietary Capital		Attachment 8, Line 14, Col. 1	
4	Less Preferred Stock		Attachment 8, Line 14, Col. 2	
5	Less Accumulated Other Comprehensive Income Account 219		Attachment 8, Line 14, Col. 4	
6	Less Account 216.1 & Goodwill		Attachment 8, Line 14, Col. 3&5	
7	Common Stock		Attachment 8, Line 14, Col. 6	
	Capitalization			
8	Long Term Debt		Attachment H-4A, page 4, Line 22, Col. 3	
9	Preferred Stock		Attachment H-4A, page 4, Line 23, Col. 3	
10	Common Stock		Attachment H-4A, page 4, Line 24, Col. 3	
11	Total Capitalization		Attachment H-4A, page 4, Line 25, Col. 3	
12	Debt %	Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 4	
13	Preferred %	Preferred Stock	Attachment H-4A, page 4, Line 23, Col. 4	
14	Common %	Common Stock	Attachment H-4A, page 4, Line 24, Col. 4	
15	Debt Cost	Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 5	
16	Preferred Cost	Preferred Stock	Attachment H-4A, page 4, Line 23, Col. 5	
17	Common Cost	Common Stock		0.1080
18	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 12*Line 15)	
19	Weighted Cost of Preferred	Preferred Stock	(Line 13*Line 16)	
20	Weighted Cost of Common	Common Stock	(Line 14*Line 17)	
21	Rate of Return on Rate Base (ROR)		(Sum Lines 18 to 20)	
22	Investment Return = Rate Base * Rate of Return		**(Line 1*Line 21)**	

Income Taxes

	Income Tax Rates	
23	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	Attachment H-4A, page 3, Line 28, Col. 3
24	CIT=(T/1-T) * (1-(WCLTD/R)) =	Calculated
25	1 / (1 - T) = (from line 23)	Attachment H-4A, page 3, line 30, Col. 3
26	Amortized Investment Tax Credit (266.8.f) (enter negative)	Attachment H-4A, page 3, Line 31, Col. 3
27	Tax Effect of Permanent Differences and AFUDC Equity	Attachment H-4A, page 3, Line 32, Col. 3
28	(Excess)/Deficient Deferred Income Taxes	Attachment H-4A, page 3, Line 33, Col. 3
29	Income Tax Calculation	(Line 22*Line 24)
30	ITC adjustment	Attachment H-4A, page 3, Line 35, Col. 5
31	Permanent Differences and AFUDC Equity Tax Adjustment	Attachment H-4A, page 3, Line 36, Col. 5
32	(Excess)/Deficient Deferred Income Tax Adjustment	Attachment H-4A, page 3, Line 37, Col. 5
33	Total Income Taxes	Sum Lines 29 to 32

Increased Return and Taxes

34	Return and Income taxes with increase in ROE	(Line 22 + Line 33)
35	Return without incentive adder	Attachment H-4A, Page 3, Line 39, Col. 5
36	Income Tax without incentive adder	Attachment H-4A, Page 3, Line 38, Col. 5
37	Return and Income taxes without increase in ROE	Line 35 + Line 36
38	Return and Income taxes with increase in ROE	Line 34
39	Incremental Return and incomes taxes for increase in ROE	Line 38 - Line 37
40	Rate Base	Line 1
41	Incremental Return and incomes taxes for increase in ROE divided by rate base	Line 39 / Line 40

Notes:
Line 17 to include an incentive ROE that is used only to determine the increase in return and incomes taxes associated with a specific increase in ROE. Any actual ROE incentive must be approved by the Commission. Until an ROE incentive is approved, line 17 will reflect the current ROE.

Gross Plant Calculation

For the 12 months ended 12/31/XXXX

			[1] Production	[2] Transmission	[3] Distribution	[4] Intangible	[5] General	[6] Common	[7] Total
1	December	20XX							
2	January	20XX							
3	February	20XX							
4	March	20XX							
5	April	20XX							
6	May	20XX							
7	June	20XX							
8	July	20XX							
9	August	20XX							
10	September	20XX							
11	October	20XX							
12	November	20XX							
13	December	20XX							
14	**13-month Average [A] [C]**								

				Production	Transmission	Distribution	Intangible	General	Common	Total
			[B]	205.46.g	207.58.g	207.75.g	205.5.g	207.99.g	356.1	
15	December	20XX								
16	January	20XX								
17	February	20XX								
18	March	20XX								
19	April	20XX								
20	May	20XX								
21	June	20XX								
22	July	20XX								
23	August	20XX								
24	September	20XX								
25	October	20XX								
26	November	20XX								
27	December	20XX								
28	13-month Average									

Asset Retirement Costs

				Production	Transmission	Distribution	Intangible	General	Common
			[B]	205.44g	207.57.g	207.74.g	company records	207.98.g	company records
29	December	20XX							
30	January	20XX							
31	February	20XX							
32	March	20XX							
33	April	20XX							
34	May	20XX							
35	June	20XX							
36	July	20XX							
37	August	20XX							
38	September	20XX							
39	October	20XX							
40	November	20XX							
41	December	20XX							
42	13-month Average			-					-

Notes:
[A] Taken to Attachment H-4A, page 2, lines 1-6, Col. 3
[B] Reference for December balances as would be reported in FERC Form 1.
[C] Balance excludes Asset Retirements Costs

Accumulated Depreciation Calculation

			[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	20XX							
2	January	20XX							
3	February	20XX							
4	March	20XX							
5	April	20XX							
6	May	20XX							
7	June	20XX							
8	July	20XX							
9	August	20XX							
10	September	20XX							
11	October	20XX							
12	November	20XX							
13	December	20XX							
14	**13-month Average**	**[A] [C]**							

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
			[B]	219.20-24.c	219.25.c	219.26.c	200.21.c	219.28.c	356.1	
15	December	20XX								
16	January	20XX								
17	February	20XX								
18	March	20XX								
19	April	20XX								
20	May	20XX								
21	June	20XX								
22	July	20XX								
23	August	20XX								
24	September	20XX								
25	October	20XX								
26	November	20XX								
27	December	20XX								
28	13-month Average									

Reserve for Depreciation of Asset Retirement Costs

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
			[B]	Company Records	Company Records	Company Records	Company Records	Company records	Company Records
29	December	20XX							
30	January	20XX							
31	February	20XX							
32	March	20XX							
33	April	20XX							
34	May	20XX							
35	June	20XX							
36	July	20XX							
37	August	20XX							
38	September	20XX							
39	October	20XX							
40	November	20XX							
41	December	20XX							
42	13-month Average			-		-	-	-	-

Notes:

[A] Taken to Attachment H-4A, page 2, lines 7-11, Col. 3
[B] Reference for December balances as would be reported in FERC Form 1.
[C] Balance excludes reserve for depreciation of asset retirement costs

			[1]	[2]	[3]	[4]	[5]	[6]
			ADIT Transmission Total (including Plant & Labor Related Transmission ADITs and applicable transmission adjustments from notes below)					
			Acct. No. 281 (enter negative)	**Acct. No. 282 (enter negative)**	**Acct. No. 283 (enter negative)**	**Acct. No. 190**	**Acct. No. 255 (enter negative)**	**Total**
				[B]	[C]	[D]	[E]	
1	December 31	20XX	-					

				[1]	[2]	[3]	[4]	[5]	[6]
				ADIT Total Transmission-related only, including Plant & Labor Related Transmission ADITs (prior to adjustments from notes below)					
				Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
2	December 31	20XX	[G]	-					

Notes:

[A] Beginning/Ending Average with adjustments for FAS143, FAS106, FAS109, CIACs and normalization to populate Appendix H-4A, page 2, lines 19-23, col. 3 for accounts 281, 282, 283, 190, and 255, respectively

[B] FERC Account No. 282 is adjusted for the following items.

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
3	20XX					

[C] FERC Account No. 283 is adjusted for the following items.

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
4	20XX					

[D] FERC Account No. 190 is adjusted for the following items:

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
5	20XX					

[E] See Attachment H-4A, page 5, note K; A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f).

[F] Sourced from Attachment 5b, page 1, col. O for PTRR & Attachment 5C, page 2, col. O for ATRR

[G] Sourced from Attachment 5a, page 1, lines 1-5, col. 4

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line	1	2 **Transmission Ending** (Note F)	3 **End Plant & Labor Related Allocated to Transmission** (page 1, col. K)	4 **Total Transmission Ending** (col. 2 + col. 3) (Note E)
1	**ADIT- 282 From Account Subtotal Below**			
2	**ADIT-283 From Account Subtotal Below**			
3	**ADIT-190 From Account Subtotal Below**			
4	**ADIT-281 From Account Subtotal Below**			
5	**ADIT-255 From Account Subtotal Below**			
	Total (sum rows 1-5)			

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line		A **End Plant Related** (Note A)	B **End Labor Related** (Note B)	C **Plant & Labor Subtotal** Col. A + Col. B	D **Gross Plant Allocator** (Note C)	E **Wages & Salary Allocator** (Note D)	F **End Plant & Labor Related ADIT** (Col. A * Col. D) + (Col. B * Col. E)
1	ADIT- 282 From Account Total Below						
2	ADIT-283 From Account Total Below						
3	ADIT-190 From Account Total Below						
4	ADIT-281 From Account Total Below						
5	ADIT-255 From Account Total Below						
6	**Subtotal**						

Notes
- A From column F (beginning on page 2)
- B From column G (beginning on page 2)
- C Refers to Attachment H-4A, page 2, line 6, col. 4
- D Refers to Attachment H-4A, page 4, line 16, col.6
- E Total Transmission Ending taken to Attachment 5, line 2
- F From column E (beginning on page 2) by account

For the 12 months ended 12/31/XXXX

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-190	**End of Year Balance p234.18.c**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
Subtotal							

Instructions for Account 190:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-282	End of Year Balance p275.9.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Subtotal							

Instructions for Account 282:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-283	**End of Year Balance p277.19.k**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
Subtotal							

Instructions for Account 283:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-281	End of Year Balance p273.8.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Subtotal							

Instructions for Account 281:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-255	**End of Year Balance p267.h**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
Subtotal							

Instructions for Account 255:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Line		A	B	C	D	E	F	G	H	I
		20XX Quarterly Activity and Balances								
1	PTRR	**Beginning 190 (including adjustments)**	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
2	PTRR	**Beginning 190 (including adjustments)**	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
3	PTRR	**Beginning 282 (including adjustments)**	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
4	PTRR	**Beginning 282 (including adjustments)**	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
5	PTRR	**Beginning 283 (Including adjustments)**	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
6	PTRR	**Beginning 283 (Including adjustments)**	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	

20XX PTRR

			J	K	L	M	N	O	P
				Page 1, B+D+F+H	Page 1, row 2,4,6 Column A+B+D+F+H	J-L		M-N	Line 7= J-N-O Lines 8-9= -J+N+O
Line		Account	Estimated Ending Balance (Before Adjustments)	Projected Activity	Prorated Ending Balance	Prorated – Estimated End (Before Adjustments)	Sum of end ADIT Adjustments	Normalization	Ending ADIT Balance Included in Formula Rate
7	PTRR	Total Account 190							
8	PTRR	Total Account 282							
9	PTRR	Total Account 283							
10	PTRR	Total ADIT Subject to Normalization							

Notes:

1. Attachment 5b will only be populated within the PTRR

Line		A	B	C	D	E	F	G	H	I
		20XX Quarterly Activity and Balances								
		Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
1	PTRR									
2	ATRR									
		Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
3	PTRR									
4	ATRR									
		Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
5	PTRR									
6	ATRR									
		Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
7	PTRR									
8	ATRR									
		Beginning 283 (Including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
9	PTRR									
10	ATRR									
		Beginning 283 (Including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
11	PTRR									
12	ATRR									

20XX PTRR

Line		Account	A Estimated Ending Balance (Before Adjustments)	B Page 1, B+D+F+H Projected Activity	C Page 1, row 3,7,11Column A+B+D+F+H Prorated Ending Balance	D A-C Prorated – Estimated End (Before Adjustments)	E Sum of end ADIT Adjustments	F D-E Normalization	G Line 1= A-E-F Lines 2-3 =A+E+F Ending ADIT Balance Included in Formula Rate
1	PTRR	Total Account 190							
2	PTRR	Total Account 282							
3	PTRR	Total Account 283							
4	PTRR	Total ADIT Subject to Normalization							

20XX ATRR

		Account	H Actual Ending Balance (Before Adjustments)	I Page 1, B+D+F+H Actual Activity	J Page 1, row 4,8,12 column A+B+D+F+H Prorated Ending Balance	K H-J Prorated – Actual End (Before Adjustments)	L D-K Prorated Activity Not Projected	M Sum of end ADIT Adjustments	N E-M ADIT Adjustments not projected	O K+L-M-N Normalization	P Line 5= H-M-O Lines 6-7= -H+M+O Ending ADIT Balance Included in Formula Rate
5	ATRR	Total Account 190									
6	ATRR	Total Account 282									
7	ATRR	Total Account 283									
8	ATRR	Total ADIT Subject to Normalization									

Notes:

Attachment 5c will only be populated within the ATRR

1	**Calculation of PBOP Expenses**		
2	**JCP&L**	**Amount**	**Source**
3	Total FirstEnergy PBOP expenses	-$155,537,000	FirstEnergy 2018 Actuarial Study
4	Labor dollars (FirstEnergy)	$2,363,633,077	FirstEnergy 2018 Actual: Company Records
5	cost per labor dollar (line 3 / line 4)	-$0.0658	
6	labor (labor not capitalized) current year, transmission only		JCP&L Labor: Company Records
7	PBOP Expense for current year (line 5 * line 6)		
8	PBOP expense in Account 926 for current year, total company		JCP&L Account 926: Company Records
9	W&S Labor Allocator		
10	Allocated Transmission PBOP (line 8 * line 9)		
11	PBOP Adjustment for Attachment H-4A, page 3, line 9 (line 7 - line 10)		
12	Lines 3-4 cannot change absent a Section 205 or 206 filing approved or accepted by FERC in a separate proceeding		

Taxes Other than Income Calculation

		[A]	**Dec 31, XXXX**
1	**Payroll Taxes**		
1a		263.i	
1b		263.i	
1c		263.i	
1d		263.i	
1z	**Payroll Taxes Total**		
2	**Highway and Vehicle Taxes**		
2a		263.i	
2z	**Highway and Vehicle Taxes**		
3	**Property Taxes**		
3a		263.i	
3b		263.i	
3c		263.i	
3d		263.i	
3z	**Property Taxes**		
4	**Gross Receipts Tax**		
4a		263.i	
4z	**Gross Receipts Tax**		
5	**Other Taxes**		
5a		263.i	
5b		263.i	
5c		263.i	
5d			
5z	**Other Taxes**		
6z	**Payments in lieu of taxes**		
7	Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z) [tie to 114.14c]		

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Capital Structure Calculation

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Proprietary Capital	**Preferred Stock**	**Account 216.1**	**Account 219**	**Goodwill**	**Common Stock**	**Long Term Debt**
			[A]	112.16.c	112.3.c	112.12.c	112.15.c	233.5.f	(1) - (2) - (3) - (4) - (5)	112.24.c
1	December	20XX								
2	January	20XX								
3	February	20XX								
4	March	20XX								
5	April	20XX								
6	May	20XX								
7	June	20XX								
8	July	20XX								
9	August	20XX								
10	September	20XX								
11	October	20XX								
12	November	20XX								
13	December	20XX								
14	13-month Average									

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Stated Value Inputs

Formula Rate Protocols
Section VIII.A

1. Rate of Return on Common Equity ("ROE")

JCP&L's stated ROE is set to: 10.8%

2. Postretirement Benefits Other Than Pension ("PBOP")

**sometimes referred to as Other Post Employment Benefits, or "OPEB"*

Total FirstEnergy PBOP expenses	-$155,537,000
Labor dollars (FirstEnergy)	$2,363,633,077
Cost per labor dollar	-$0.0658

3. Depreciation Rates [1][2]

FERC Account	Depr %
350.2	1.53%
352	1.14%
353	2.43%
354	0.83%
355	1.95%
356	2.45%
356.1	1.09%
357	1.39%
358	1.88%
359	1.10%
389.2	3.92%
390.1	1.51%
390.2	0.46%
391.1	4.00%
391.15	5.00%
391.2	20.00%
391.25	20.00%
392	3.84%
393	3.33%
394	4.00%
395	5.00%
396	3.03%
397	5.00%
398	5.00%

Note:

[1] Account 303 amortization period is 7 years.
[2] Accounts 391.10, 391.15, 391.20, 391.25, 393, 394, 395, 397, and 398 have an unrecovered reserve to be amortized over 5 years separately from the assets in these accounts beginning January 1, 2020 through December 31, 2025.

Debt Cost Calculation

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED 12/31/20XX

	t=N	(a) Issue Date	(b) Maturity Date	(c) ORIGINAL ISSUANCE (table 2, col. cc)	(d) Net Proceeds At Issuance (table 2, col. hh)	(e) Net Amount Outstanding at t=N	(f) Months Outstanding at t=N	(g) Average Net Outstanding in Year* z* ((col e. * col. F)/12)	(h) Weighted Outstanding Ratios (col. g/col. g total)	(i) Effective Cost Rate (Table 2, Col. II)	(j) Weighted Debt Cost at t = N (h) * (i)
Long Term Debt Cost at Year Ended:	**12/31/20XX**										
First Mortgage Bonds:											
(1)											
(2)											
(3)											
(4)											
(5)											
											**

t = time
The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.
The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.
* z = Average of monthly balances for months outstanding during the year (average of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).
Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).
** This Total Weighted Average Debt Cost will be shown on page 4, line 22, column 5 of formula rate Attachment H-4A.

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED 12/31/20XX

	Long Term Debt Issuances	Affiliate	(aa) Issue Date	(bb) Maturity Date	(cc) Amount Issued	(dd) (Discount) Premium at Issuance	(ee) Issuance Expense	(ff) Loss/Gain on Reacquired Debt	(gg) Less Related ADIT	(hh) Net Proceeds (col. cc + col. dd - col. ee - col. ff)	(ii) Net Proceeds Ratio ((col. hh / col. cc) *100)	(jj) Coupon Rate	(kk) Annual Interest (col. cc *col. jj)	(ll) Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
(1)														
(2)														
(3)														
(4)														
(5)														
	TOTALS													

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation
Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_o equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-4A

					Columns 5-9 (page 1) only applies with incentive ROE project(s) (Note F)				
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.		**Reference**	**Transmission**	**Allocator**	Line No.		**Reference**	**Transmission**	**Allocator**
1	Gross Transmission Plant - Total	Attach. H-4A, p. 2, line 2, col. 5 (Note A)							
2	Net Transmission Plant - Total	Attach. H-4A, p. 2, line 14, col. 5 (Note B)							
	O&M EXPENSE								
3	Total O&M Allocated to Transmission	Attach. H-4A, p. 3, line 14, col. 5							
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)							
	GENERAL, INTANGIBLE, AND COMMON (G,I, & C) DEPRECIATION EXPENSE								
5	Total G, I, & C depreciation expense	Attach. H-4A, p. 3, lines 16 & 17, col. 5							
6	Annual allocation factor for G, I, & C depreciation expense	(line 5 divided by line 1, col. 3)							
	TAXES OTHER THAN INCOME TAXES								
7	Total Other Taxes	Attach. H-4A, p. 3, line 27, col. 5							
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col. 3)							
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, & 8**							
	INCOME TAXES					INCOME TAXES			
10	Total Income Taxes	Attach. H-4A, p. 3, line 38, col. 5			10b	Total Income Taxes	Attachment 2, line 33		
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2, col. 3)			11b	Annual Allocation Factor for Income Taxes	(line 10b divided by line 2, col. 3)		
	RETURN					RETURN			
12	Return on Rate Base	Attach. H-4A, p. 3, line 39, col. 5			12b	Return on Rate Base	Attachment 2, line 22		
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2, col. 3)			13b	Annual Allocation Factor for Return on Rate Base	(line 12b divided by line 2, col. 3)		
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**			**14b**	**Annual Allocation Factor for Return**	**Sum of line 11b and 13b**		
					15	**Additional Annual Allocation Factor for Return**	**Line 14 b, col. 9 less line 14, col. 4**		

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-4A

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	**Project Name**	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**Additional Incentive Annual Allocation**	**Total Annual Revenue Requirement**	**True-up Adjustment**	**Net Revenue Requirement**
1			(Note C & H)	(Page 1, line 9)	(Col. 3 * Col. 4)	(Note D & H)	Page 1, line 14	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8, & 9)	(Col. 6 * Page 1, line 15, Col. 9)	(Sum Col. 10 & 11)	(Note G)	(Sum Col. 12 & 13)

3 Transmission Enhancement Credit taken to Attachment H-4A Page 1, Line 7
4 Additional Incentive Revenue taken to Attachment H-4A, Page 3, Line 41

Notes

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-4A.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-4A.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 above. This value includes subsequent capital investments required to maintain the project in-service.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-4A, page 3, line 15.
F Any actual ROE incentive must be approved by the Commission
G True-up adjustment is calculated on the project true-up schedule, attachment 12 column j
H Based on a 13-month average

TEC Worksheet Support
Net Plant Detail

Line No.	Project Name	RTEP Project Number	Project Gross Plant	Dec-XX	Jan-XX	Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sep-XX	Oct-XX	Nov-XX	Dec-XX
			(Note A)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)

NOTE:
[A] Project Gross Plant is the total capital investment for the project, including subsequent capital investments required to maintain the project in-service. Utilizing a 13-month average. [D] Company records

TEC Worksheet Support
Net Plant Detail

Accumulated Depreciation	**Dec-XX**	**Jan-XX**	**Feb-XX**	**Mar-XX**	**Apr-XX**	**May-XX**	**Jun-XX**	**Jul-XX**	**Aug-XX**	**Sep-XX**	**Oct-XX**	**Nov-XX**	**Dec-XX**		**Project Net Plant**
(Note B)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)		(Note B & C)

NOTE

[B] Utilizing a 13-month average [C] Taken to Attachment 11, Page 2, Col.6 [D] Company records

TEC – True-up

To be completed after Attachment 11 for the True-up Year is updated using actual data

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.		**Project Name**	**RTEP Project Number**	**Actual Revenues for Attachment 11**	**Projected Annual Revenue Requirement**	**% of Total Revenue Requirement**	**Revenue Received**	**Actual Annual Revenue Requirement**	**True-up Adjustment Principal Over/(Under)**	**Applicable Interest Rate on Over/(Under)**	**Total True-up Adjustment with Interest Over/(Under)**
					Projected Attachment 11 p 2 of 2, col. 14	Col d, line 2 / col. d, line 3	Col c, line 1 * Col e	Actual Attachment 11 p 2 of 2, col. 14	Col. f - Col. G	Col. H line 2x / Col. H line 3* Col. J line 4	Col. h + Col. i
1	[A]	Actual RTEP Credit Revenues for true-up year		0							
2a		Project 1			-	-	-	-	-		
2b		Project 2				-	-		-		
2c		Project 3				-	-		-		
3		Subtotal			-			-	-		
4		Total Interest (Sourced from Attachment 13a, line 30)									-

NOTE

[A] Amount included in revenues reported on pages 328-330 of FERC Form 1.

Net Revenue Requirement True-up with Interest

	Reconciliation Revenue Requirement For Year 20XX Available June 10, 20XX		20XX Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 20XX		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	Average Monthly	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.0000%				
	An over or under collection will be recovered prorata over 20XX, held for 20XX and returned prorate over 20XX							
	Calculation of Interest					**Monthly**		
3	January	Year 20XX	-	0.0000%	12	-		-
4	February	Year 20XX	-	0.0000%	11	-		-
5	March	Year 20XX	-	0.0000%	10	-		-
6	April	Year 20XX	-	0.0000%	9	-		-
7	May	Year 20XX	-	0.0000%	8	-		-
8	June	Year 20XX	-	0.0000%	7	-		-
9	July	Year 20XX	-	0.0000%	6	-		-
10	August	Year 20XX	-	0.0000%	5	-		-
11	September	Year 20XX	-	0.0000%	4	-		-
12	October	Year 20XX	-	0.0000%	3	-		-
13	November	Year 20XX	-	0.0000%	2	-		-
14	December	Year 20XX	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 20XX	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
16	January	Year 20XX	-	0.0000%		-	-	-
17	February	Year 20XX	-	0.0000%		-	-	-
18	March	Year 20XX	-	0.0000%		-	-	-
19	April	Year 20XX	-	0.0000%		-	-	-
20	May	Year 20XX	-	0.0000%		-	-	-
21	June	Year 20XX	-	0.0000%		-	-	-
22	July	Year 20XX	-	0.0000%		-	-	-
23	August	Year 20XX	-	0.0000%		-	-	-
24	September	Year 20XX	-	0.0000%		-	-	-
25	October	Year 20XX	-	0.0000%		-	-	-
26	November	Year 20XX	-	0.0000%		-	-	-
27	December	Year 20XX	-	0.0000%		-	-	-
						-		
28	True-Up with Interest					$	-	
29	Less Over (Under) Recovery					$	-	
30	Total Interest					$	-	

[A] Interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if JCP&L does not have short term debt

TEC Revenue Requirement True-up with Interest

	TEC Reconciliation Revenue Requirement For Year 20XX Available June 10, 20XX		TEC 20XX Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 20XX		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	Average Monthly	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.0000%				
	An over or under collection will be recovered prorata over 20XX, held for 20XX and returned prorate over 20XX							
	Calculation of Interest					**Monthly**		
3	January	Year 20XX	-	0.0000%	12	-		-
4	February	Year 20XX	-	0.0000%	11	-		-
5	March	Year 20XX	-	0.0000%	10	-		-
6	April	Year 20XX	-	0.0000%	9	-		-
7	May	Year 20XX	-	0.0000%	8	-		-
8	June	Year 20XX	-	0.0000%	7	-		-
9	July	Year 20XX	-	0.0000%	6	-		-
10	August	Year 20XX	-	0.0000%	5	-		-
11	September	Year 20XX	-	0.0000%	4	-		-
12	October	Year 20XX	-	0.0000%	3	-		-
13	November	Year 20XX	-	0.0000%	2	-		-
14	December	Year 20XX	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 20XX	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
16	January	Year 20XX	-	0.0000%		-	-	-
17	February	Year 20XX	-	0.0000%		-	-	-
18	March	Year 20XX	-	0.0000%		-	-	-
19	April	Year 20XX	-	0.0000%		-	-	-
20	May	Year 20XX	-	0.0000%		-	-	-
21	June	Year 20XX	-	0.0000%		-	-	-
22	July	Year 20XX	-	0.0000%		-	-	-
23	August	Year 20XX	-	0.0000%		-	-	-
24	September	Year 20XX	-	0.0000%		-	-	-
25	October	Year 20XX	-	0.0000%		-	-	-
26	November	Year 20XX	-	0.0000%		-	-	-
27	December	Year 20XX	-	0.0000%		-	-	-
						-		

28	True-Up with Interest	$	-
29	Less Over (Under) Recovery	$	-
30	Total Interest	$	-

[A] Interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if JCP&L does not have short term debt

Other Rate Base Items

				[1]	[2]	[3]	[4]	[5]	[6]
				Land Held for Future Use	**Materials & Supplies**	**Prepayments (Account 165)**		**Total**	
			[A]	214.x.d	227.8.c &.16.c	111.57.c[B]			
1	December 31	20XX		-	-				
2	December 31	20XX		-	-				
3	Begin/End Average			-	-				

				Unfunded Reserve - Plant Related					**Total**
		FERC Acct No.		**228.1**	**228.2**	**228.3**	**228.4**	**242**	
		[A]	[C]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c	
4	December 31	20XX		-	-	-	-	-	-
5	December 31	20XX		-	-	-	-	-	-
6	Begin/End Average			-	-	-	-	-	-

				Unfunded Reserve - Labor Related						**Total**
		FERC Acct No.		**228.1**	**228.2**	**228.3**	**228.4**	**242**		
		[A]	[C]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c		
7	December 31	20XX		-	-	-	-	-	-	-
8	December 31	20XX		-	-	-	-	-	-	-
9	Begin/End Average			-	-	-	-	-	-	-

Notes:
[A] Reference for December balances as would be reported in FERC Form 1.
[B] Prepayments shall exclude prepayments of income taxes.
[C] Includes transmission-related balance only

Income Tax Adjustments

	[1]	[2]	[3]	
			Dec 31, 20XX	Reference
1	Tax adjustment for Permanent Differences & AFUDC Equity	[A][C]		JCP&L Company Records
2	Amortized Excess Deferred Taxes (enter negative)	[B][C]		JCP&L Company Records
3	Amortized Deficient Deferred Taxes	[B][C]		JCP&L Company Records

Notes:

[A] AFUDC equity component is the gross cumulative annual amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function.

[B] Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. The balance located within Column 3, row 2 and row 3, is the net impact of excess deferred and deficient amortization.

[C] Year end balance for line 1 taken to Attachment H-4A, page 3, line 32; Year end balance for lines 2-3 taken to Attachment H-4A, page 3, line 33

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Line No.	**Description**	**EDIT Transmission Allocation**	**Amortization Period**	**Years Remaining at Year End**	**Amortization of EDIT**	**Protected (P) Non-Protected (N)**
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30	Total Non-Property Amortization (Total of lines 1 thru 29)					
31	**Property Book-Tax Timing Difference [B] [C]**					N & P
32	**Total Non-Property & Property Amortization [A] [B] [C]**					N & P

Notes:

Above amortization is populated from company records

[A] Ties to Attachment 15, page 1, line 2, column 3 for net excess & Attachment 15, page 1, line 3, Column 3 for net deficient

[B] The amortization schedule of the EDIT balance related to Tax Cuts and Job Act of 2017 shall be consistent with the following periods:

Protected Property & Non-Protected Property	ARAM
Non-Protected, Non-Property:	10 years
Protected, Non-Property:	35 years

[C] The regulatory assets and liabilities, included in FERC accounts 182.3 and 254, respectively, will amortize through FERC income statement accounts 410.1 and 411.1

Abandoned Plant

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
2	December 20XX	p111.71.d (and Notes)	13				
3	January	FERC Account 182.2	12				
4	February	FERC Account 182.2	11				
5	March	FERC Account 182.2	10				
6	April	FERC Account 182.2	9				
7	May	FERC Account 182.2	8				
8	June	FERC Account 182.2	7				
9	July	FERC Account 182.2	6				
10	August	FERC Account 182.2	5				
11	September	FERC Account 182.2	4				
12	October	FERC Account 182.2	3				
13	November	FERC Account 182.2	2				
14	December 20XX	p111.71.c (and Notes) Detail on p230b	1				
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13					
					Attachment H-4A, page 3, Line 18		Attachment H-4A, page 2, Line 27

Note:
Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC and will be zero until the Commission accepts or approves recovery of the cost of abandoned plant

For the 12 months ended 12/31/XXXX

			CWIP [A] 216.b
1	December	20XX	
2	January	20XX	
3	February	20XX	
4	March	20XX	
5	April	20XX	
6	May	20XX	
7	June	20XX	
8	July	20XX	
9	August	20XX	
10	September	20XX	
11	October	20XX	
12	November	20XX	
13	December	20XX	
14	13-month Average		-

Notes:
[A] Includes only CWIP authorized by the Commission for inclusion in rate base.

Federal Income Tax Rate

Nominal Federal Income Tax Rate (entered on Attachment H-4A, page 5 of 5, Note K)	

State Income Tax Rate

	New Jersey	Combined Rate (entered on Attachment H-4A, page 5 of 5, Note K)
Nominal State Income Tax Rate		
Times Apportionment Percentage		
Combined State Income Tax Rate		

Regulatory Asset

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Months Remaining In Amortization		Amortization Expense	Additions	
1	**Monthly Balance**	Source	Period	Beginning Balance	(Company Records)	(Deductions)	Ending Balance
2	December 20XX	p232 (and Notes)	13				
3	January	FERC Account 182.3	12				
4	February	FERC Account 182.3	11				
5	March	FERC Account 182.3	10				
6	April	FERC Account 182.3	9				
7	May	FERC Account 182.3	8				
8	June	FERC Account 182.3	7				
9	July	FERC Account 182.3	6				
10	August	FERC Account 182.3	5				
11	September	FERC Account 182.3	4				
12	October	FERC Account 182.3	3				
13	November	FERC Account 182.3	2				
14	December 20XX	p232 (and Notes)	1				
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13					

Operation and Maintenance Expenses

FF1 Page 321 Line No.	Account Reference	Description	Account Balance [A]
82		***Operation***	
83	560	Operation Supervision and Engineering	
84			
85	561.1	Load Dispatch-Reliability	
86	561.2	Load Dispatch-Monitor and Operate Transmission System	
87	561.3	Load-Dispatch-Transmission Service and Scheduling	
88	561.4	Scheduling, System Control and Dispatch Services	
89	561.5	Reliability, Planning and Standards Development	
90	561.6	Transmission Service Studies	
91	561.7	Generation Interconnection Studies	
92	561.8	Reliability, Planning and Standards Development Services	
93	562	Station Expenses	
94	563	Overhead Lines Expense	
95	564	Underground Lines Expense	
96	565	Transmission of Electricity by Others	
97	566	Miscellaneous Transmission Expense	
98	567	Rents	
99		TOTAL Operation (Enter Total of Lines 83 thru 98)	$0
100		***Maintenance***	
101	568	Maintenance Supervision and Engineering	
102	569	Maintenance of Structures	
103	569.1	Maintenance of Computer Hardware	
104	569.2	Maintenance of Computer Software	
105	569.3	Maintenance of Communication Equipment	
106	569.4	Maintenance of Miscellaneous Regional Transmission Plant	
107	570	Maintenance of Station Equipment	
108	571	Maintenance of Overhead Lines	
109	572	Maintenance of Underground Lines	
110	573	Maintenance of Miscellaneous Transmission Plant	
111		TOTAL Maintenance (Total of lines 101 thru 110)	$0
112		**TOTAL Transmission Expenses (Total of lines 99 and 111)**	**$0**

Notes:

[A] December balances as would be reported in FERC Form 1

Administrative and General (A&G) Expenses

FF1 Page 323 Line No.	Account Reference	Description	Account Balance [B]
180		***Operation***	
181	920	Administrative and General Salaries	
182	921	Office Supplies and Expenses	
183	Less 922	Administrative Expenses Transferred - Credit	
184	923	Outside Services Employed	
185	924	Property Insurance	
186	925	Injuries and Damages	
187	926	Employee Pensions and Benefits	
188	927	Franchise Requirements	
189	928	Regulatory Commission Expense	
190	Less 929	(Less) Duplicate Charges-Cr.	
191	930.1	General Advertising Expenses	
192	930.2	Miscellaneous General Expenses	
193	931	Rents	
194		**Total Operation (Enter Total of lines 181 thru 193)**	$0
195		***Maintenance***	
196	935	Maintenance of General Plant	
197		**TOTAL A&G Expenses (Total of lines 194 and 196)**	**$0**

Notes:

[B] December balances as would be reported in FERC Form 1, Transmission only

ATTACHMENT H-4B

Jersey Central Power & Light Company

Formula Rate Implementation Protocols

ANNUAL TRUE-UP, INFORMATION EXCHANGE, AND CHALLENGE PROCEDURES

Definitions

“Actual Transmission Revenue Requirement” or “ATRR” means the actual net transmission revenue requirement calculated and posted on the PJM website no later than June 10 of each year subsequent to calendar year 2020 for the immediately preceding calendar year in accordance with JCP&L’s Formula Rate and based upon JCP&L’s actual costs and expenditures.

“Annual Update” means JCP&L’s ATRR for the preceding calendar year, as well as the True-up for the prior Rate Year, as posted on or before June 10 of each year.

“Formal Challenge” means a written challenge to an Annual Update or Projected Transmission Revenue Requirement submitted to the Federal Energy Regulatory Commission (the “Commission” or “FERC”) as provided in Section IV below.

“Formula Rate” means the collection of formulas and worksheets, unpopulated with any data, included as Attachment H-4A of the PJM Tariff.

“Interested Parties” include, but are not limited to, customers under the PJM Tariff, state utility regulatory commissions, the Organization of PJM States, Inc., consumer advocacy agencies, and state attorneys general.

“PJM Tariff” means the Open Access Transmission Tariff of the PJM Interconnection, L.L.C.

“Preliminary Challenge” means a written challenge to the Annual Update or Projected Transmission Revenue Requirement submitted to JCP&L as provided in Section IV below.

“Projected Transmission Revenue Requirement” or “PTRR” means the projected net transmission revenue requirement calculated for the forthcoming Rate Year, as well as, where applicable, the most recently calculated True-up, with interest, to be posted on the PJM website no later than October 31 of each year for rates effective the next calendar year starting January 1.

“Protocols” means these Protocols, included as Attachment H-4B of the PJM Tariff).

"Publication Date" means the date on which the Annual Update is posted.

"Rate Year" means the twelve consecutive month period that begins on January 1 and continues through December 31.

"True-up" means the difference between the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) and the ATRR for the same Rate Year, which shall be provided in the Annual Update on or before June 10 of the year subsequent to the Rate Year. The True-up will be a component of the PTRR.

Section I. Applicability

The following procedures shall apply to the Jersey Central Power & Light Company ("JCP&L") calculation of its Actual Transmission Revenue Requirement, True-up, and Projected Transmission Revenue Requirement.

Section II. Annual Update and Projected Transmission Revenue Requirement

A. On or before June 10 of each year subsequent to calendar year 2020, JCP&L shall determine its Annual Update for the immediately preceding calendar year under Attachment H-4A and Section VII of these Protocols, including calculation of the True-up to be included in JCP&L's PTRR for the subsequent Rate Year.

B. On or before June 10 of each year subsequent to calendar year 2020, JCP&L shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website. Within two (2) days of such posting, JCP&L shall provide notice of such posting via an e-mail exploder list.

C. On or before October 31, 2020, and on or before each subsequent October 31, JCP&L shall provide the PTRR to PJM and cause such information to be posted on the PJM website, in both a Portable Document Format ("PDF") and fully-functioning Excel file, and within two (2) days of posting of the PTRR, JCP&L shall provide notice of such posting via an e-mail exploder list.

D. If the date for posting the Annual Update or PTRR falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual Update occurs shall be that year's Publication Date. Any delay in the Publication Date or in the posting of the PTRR will result in an equivalent extension of time for the submission of information requests discussed in Section III of these Protocols.

E. The ATRR shall:

1. Include a workable data-populated version of the Formula Rate template and underlying work papers in Excel format with all formulas and links intact;

2. Be based on JCP&L's FERC Form No. 1 for the prior calendar year;

3. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the ATRR that are not otherwise available in the FERC Form No. 1, subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC's Model Protective Order;

4. Provide sufficient information to enable Interested Parties to replicate the calculation of the ATRR results from the FERC Form No. 1;

5. Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1;

6. Identify and, to the extent not explained in a worksheet included in the ATRR, explain, all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in the FERC Form No. 1;

7. Provide underlying data for Formula Rate inputs that provide greater granularity than is required for the FERC Form No. 1;

8. With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

    a. Identify any Accounting Change, including:

        i. the initial implementation of an accounting standard or policy;

        ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

        iii. correction of errors and prior period adjustments that affect the ATRR and True-up calculation;

        iv. the implementation of new estimation methods or policies that change prior estimates; and

        v. changes to income tax elections;

b. Identify items included in the ATRR at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the ATRR; and

d. Provide, for each item identified pursuant to items II.E.8.a - II.E.8.c above, a narrative explanation of the individual impact of such change on the ATRR; and

9. Include for the applicable Rate Year the following information related to affiliate cost allocation: (A) a detailed description of the methodologies used to allocate and directly assign costs between JCP&L and its affiliates by service category and function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; and (B) the magnitude of such costs that have been allocated or directly assigned between JCP&L and each affiliate by service category or function.

F. The Projected Transmission Revenue Requirement shall:

1. Include a workable data-populated version of the Formula Rate template and underlying work papers in Excel format with all formulas and links intact;

2. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the PTRR;

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the PTRR;

4. With respect to any Accounting Change:

a. Identify any Accounting Change, including:

i. the initial implementation of an accounting standard or policy;

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. correction of errors and prior period adjustments that affect the PTRR calculation;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the PTRR at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the PTRR; and

d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these Protocols, a narrative explanation of the individual impact of such change on the PTRR.

G. JCP&L shall hold an open meeting among Interested Parties ("Annual Update Meeting"), to be conducted via Internet webcast, no earlier than ten (10) business days following the Publication Date and no later than July 10. No fewer than seven (7) days prior to such Annual Update Meeting, JCP&L shall provide notice on PJM's website of the time and date of the Annual Update Meeting, and shall provide notice of the posting via an e-mail exploder list. The Annual Update Meeting shall: (i) permit JCP&L to explain and clarify its ATRR and True-up; and (ii) provide Interested Parties an opportunity to seek information and clarifications from JCP&L about the ATRR and True-up.

H. JCP&L shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting"), to be conducted via Internet webcast, no earlier than five (5) business days following the posting of the PTRR (as described in Section II.C of these Protocols) and no later than November 30. No fewer than five (5) days prior to such Annual Projected Rate Meeting, JCP&L shall provide notice on PJM's website of the time and date of the Annual Projected Rate Meeting, and shall provide notice of the posting via an e-mail exploder list. The Annual Projected Rate Meeting shall: (i) permit JCP&L to explain and clarify its PTRR and (ii) provide Interested Parties an opportunity to seek information and clarifications from JCP&L about the PTRR.

Section III. Information Exchange Procedures

Each Annual Update and PTRR shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until January 15 following the Publication Date (unless such period is extended with the written consent of JCP&L or by FERC order) to serve reasonable information and document requests on JCP&L ("Information Exchange Period"). If January 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

1. the extent or effect of an Accounting Change;
2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these Protocols;
3. the proper application of the Formula Rate and procedures in these Protocols;
4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the ATRR or PTRR;
5. the prudence of actual costs and expenditures;
6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or
7. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

The information and document requests shall not be directed to ascertaining whether the Formula Rate is just and reasonable.

B. JCP&L shall make a good faith effort to respond to any information and document request within fifteen (15) business days of receipt of such request. JCP&L shall respond to all information and document requests by no later than February 25 following the Publication Date, unless the Information Exchange Period is extended by JCP&L or FERC.

C. JCP&L will serve all information requests from Interested Parties and JCP&L's response(s) to such requests upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such information requests or responses, as needed, under non-disclosure agreements that are based on FERC's Model Protective Order.

D. JCP&L shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any proceeding addressing JCP&L's Annual Update or PTRR, and such responses may be included in any Formal Challenge or other submittal addressing JCP&L's Annual Update or PTRR.

Section IV. Challenge Procedures

A. Interested Parties shall have until March 31 following the Publication Date (unless such period is extended with the written consent of JCP&L or by FERC order) ("Review Period"), to review the inputs, supporting explanations, allocations and calculations and to notify JCP&L in writing, which may be made electronically, of any specific Preliminary Challenges to the Annual Update or PTRR. If the final day of the Review Period falls on a holiday recognized by FERC, the deadline for submitting all Preliminary Challenges shall be extended to the next business day. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update or PTRR shall bar pursuit of such issue with respect to that Annual Update or PTRR under the challenge procedures set forth in these Protocols, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update or PTRR. This Section IV.A in no way shall affect a party's rights under Federal Power Act ("FPA") section 206 as set forth in Section IV.I of these Protocols.

B. Preliminary Challenges shall be subject to the resolution procedures and limitations in this Section IV and shall satisfy all of the following requirements.

1. A party submitting a Preliminary Challenge to JCP&L must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge.

2. JCP&L shall make a good faith effort to respond to any Preliminary Challenge within twenty (20) business days of written receipt of such challenge.

3. JCP&L, and where applicable, PJM, shall appoint a senior representative to work with each party that submitted a Preliminary Challenge (or its representative) toward a resolution of the challenge.

4. If JCP&L disagrees with such challenge, JCP&L will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information.

5. No Preliminary Challenge may be submitted after March 31, and JCP&L must respond to all Preliminary Challenges by no later than April 30 unless the Review Period is extended by JCP&L or FERC, or as provided in Section IV.A above.

6. JCP&L will serve all Preliminary Challenges and JCP&L's response(s) to such Preliminary Challenges upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such Preliminary Challenges or responses, as needed, under non-disclosure agreements that are based on the FERC's Model Protective Order.

C. Formal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy all of the following requirements.

1. A Formal Challenge shall:

   a. Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or these Protocols;

   b. Explain how the action or inaction violates the filed Formula Rate or these Protocols;

   c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

      (i) the extent or effect of an Accounting Change;

      (ii) whether the ATRR or PTRR fails to include data properly recorded in accordance with these Protocols;

      (iii) the proper application of the Formula Rate and procedures in these Protocols;

      (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the ATRR or PTRR;

      (v) the prudence of actual costs and expenditures;

      (vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

      (vii) any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

   d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the challenged action or inaction;

   e. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

   f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

   g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

   h. State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the challenged action or inaction raised by the Formal Challenge, and, if not, describe why not.

2. Service. Any person filing a Formal Challenge must serve a copy of such Formal Challenge on JCP&L. Service to JCP&L must be simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. A party filing a Formal Challenge shall serve the individual listed as the contact person on JCP&L's Informational Filing required under Section VI of these Protocols.

D. Preliminary and Formal Challenges shall be limited to all issues that may be necessary to determine:

1. the extent or effect of an Accounting Change;

2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these Protocols, or includes data not properly recorded in accordance with these Protocols;

3. the proper application of the Formula Rate and procedures in these Protocols;

4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the ATRR and PTRR;

5. the prudence of actual costs and expenditures included as inputs to the Formula Rate;

6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

7. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

E. Any changes or adjustments to the ATRR and PTRR resulting from the information exchange and Preliminary Challenge processes that are agreed to by JCP&L will be reported in the Informational Filing required pursuant to Section VI of these Protocols. Any such changes or adjustments agreed to by JCP&L on or before December 1 will be reflected in the PTRR for the upcoming Rate Year. Any changes or adjustments agreed to by JCP&L after December 1 will be reflected in the following year's Annual Update, as discussed in Section V of these Protocols.

F. An Interested Party shall have until June 1 following the Review Period (unless such date is extended with the written consent of JCP&L to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with FERC, which shall be served on JCP&L on the date of such filing as specified in Section IV.C.2 above. A Formal

Challenge shall be filed in the same docket as JCP&L's Informational Filing discussed in Section VI of these Protocols. JCP&L shall respond to the Formal Challenge by the deadline established by FERC. An Interested Party may not pursue a Formal Challenge unless it submitted a Preliminary Challenge on some issue (which may be different from the Formal Challenge issue) during the applicable Review Period.

G. In any proceeding initiated by FERC concerning the Annual Update or PTRR or in response to a Formal Challenge, JCP&L shall bear the burden, consistent with FPA section 205, of proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols, that it followed the applicable requirements and procedures in the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

H. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of JCP&L to file unilaterally, pursuant to FPA section 205 and the regulations thereunder, to change these Protocols, the Formula Rate, or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to FPA section 206.

I. No party shall seek to modify these Protocols or the Formula Rate under the challenge procedures set forth in these Protocols, and the Annual Update and PTRR shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to these Protocols or the Formula Rate will require, as applicable, a FPA section 205 or section 206 proceeding. JCP&L may, at its discretion and at a time of its choosing, make a limited filing pursuant to FPA section 205 to modify stated values in the Formula Rate for (a) amortization and depreciation rates, (b) Post-Employment Benefits Other Than Pensions rates, or (c) to make any changes required in a final FERC rulemaking associated with excess/deficient deferred income taxes. The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.

J. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1 shall first raise the matter with JCP&L in accordance with this Section IV before pursuing a Formal Challenge.

Section V. Changes to Actual Transmission Revenue Requirement or Projected Transmission Revenue Requirement

A. Except as provided in Section IV.E of these Protocols, any changes to the data inputs, including but not limited to revisions to JCP&L's FERC Form No. 1, or as the result of any FERC proceeding to consider the ATRR or PTRR, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the PTRR for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these Protocols.

Section VI. Informational Filings

A. By June 10 of each year, JCP&L shall submit to FERC an informational filing ("Informational Filing") of its PTRR for the Rate Year, including its ATRR and True-up. This Informational Filing must include information that is reasonably necessary to determine:

1. that input data to the Formula Rate are properly recorded in any underlying work papers;
2. that JCP&L has properly applied the Formula Rate and these Protocols;
3. the accuracy of data and the consistency with the Formula Rate of the transmission revenue requirement and rates under review;
4. the extent of Accounting Changes that affect Formula Rate inputs; and
5. the reasonableness of projected costs.

The Informational Filing must also describe any corrections or adjustments made during the period since the Publication Date, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Preliminary Challenge or Formal Challenge procedures.

Finally, the Informational Filing shall include for the applicable Rate Year the following information related to affiliate cost allocation: a detailed description of the methodologies used to allocate and directly assign costs between JCP&L and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; the magnitude of such costs that have been allocated or directly assigned between JCP&L and each affiliate by service category or function; and a copy of any service agreement between JCP&L and any JCP&L affiliate that went into effect during the Rate Year.

Within five (5) days of such Informational Filing, JCP&L shall provide notice of the Informational Filing via an e-mail exploder list and by posting the docket number assigned to JCP&L's Informational Filing on the PJM website, subject to the protection of any confidential information contained in the Informational Filing, as needed, under nondisclosure agreements that are based on FERC's Model Protective Order.

B. Any challenges to the implementation of the Formula Rate must be made through the challenge procedures described in Section IV of these Protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

Section VII. Calculation of True-up

The True-up will be determined in the following manner:

A. As part of the Annual Update for each Rate Year, JCP&L shall determine the difference between the revenues collected by PJM based on the PTRR for the Rate Year (net of the True-up from the prior year) and the ATRR for the same Rate Year based on actual cost data as reflected in its FERC Form No. 1. The True-up will be determined as follows:

   i. The ATRR for the previous Rate Year as determined using JCP&L's completed FERC Form No. 1 report shall be compared to the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) for that same Rate Year ("True-up Year") to determine any excess or shortfall in the revenues collected by PJM in the True-up Year. The revenue excess or shortfall determined by this comparison shall constitute the "True-up."

   ii. Interest on any True-up shall be based on the interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. § 35.19a; or (ii) the interest rate determined by 18 CFR § 35.19a, if JCP&L does not have short-term debt. Interest rates will be used to calculate the time value of money for the period that the True-up exists. The interest rate to be applied to the True-up will be determined using the average rate for the twenty (20) months preceding September 1 of the current year.

B. JCP&L will post on PJM's website all information relating to the True-up as part of the Annual Update. As provided in Section II.B of these Protocols, JCP&L shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website on or before June 10 of each year subsequent to calendar year 2020.

Section VIII. Formula Rate Inputs

A. Stated inputs to the Formula Rate: For (i) rate of return on common equity; (ii) "Post-Employment Benefits other than Pension" ("PBOP") charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions; and (iii) depreciation and/or amortization rates, the values in the Formula Rate shall be stated values and may be changed only pursuant to a FPA section 205 or section 206 proceeding. These stated-value inputs are specified in Attachment 9 of the Formula Rate.

B. Unpopulated Formula Rate line items: With respect to line items in the Formula Rate that are not currently populated with non-zero numerical values because FERC policy requires prior authorization for recovery of the underlying costs or because, due to the nature of the associated functional activities, such costs are not considered part of JCP&L's transmission-related revenue requirement (but not line items that are zero values in a particular Rate Year for the sole reason that no such costs or revenues were incurred or revenues received or projected to be incurred or received during the Rate Year), such line items shall not be populated with non-zero values except as may be authorized following a FPA section 205 or section 206 proceeding.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jersey Central Power & Light Company	)	Docket No. ER20-___-000

DIRECT TESTIMONY
OF
ROGER D. RUCH

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roger D. Ruch 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 employed by FirstEnergy Service Company (the "Service Company") as the Director of Rates Support in our Rates and Regulatory Affairs organization. I have been employed by affiliates of FirstEnergy Corp. ("FirstEnergy") for over 20 years in various roles within the Service Company and its affiliate FirstEnergy Solutions. The Rates Support Group, which I lead in my current role, is responsible for the regulatory requirements associated with the transmission businesses within FirstEnergy including the stand-alone transmission companies American Transmission Systems, Incorporated, Trans-Allegheny Interstate Line Company, Mid-Atlantic Interstate Transmission, LLC and Potomac-Appalachian Transmission Highline, LLC, as well as the transmission businesses of FirstEnergy Utility Operating Companies Jersey Central Power & Light Company ("JCP&L"), Potomac Edison Company, West Penn Power Company and Monongahela Power Company. With respect to the transmission companies, the Rates Support Group administers formula rates and associated Federal Energy Regulatory Commission ("FERC") filings, and interacts with interested parties in accordance with established protocols, including conducting open meetings to review and explain annual formula rate filings. The Rates Support Group is also responsible for oversight and the analytical support required for other regulatory filings, primarily at the federal level as well as support to the stakeholder process at PJM Interconnection, L.L.C. ("PJM") with respect to rate-related activities and initiatives.

Q. PLEASE PROVIDE YOUR EDUCATION, PROFESSIONAL BACKGROUND AND RELEVANT EXPERIENCE.

A. My education, professional background and relevant experience are shown in Exhibit No. JCP-101.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this testimony on behalf of Jersey Central Power & Light Company ("JCP&L"). JCP&L is a New Jersey electric public utility primarily engaged in the transmission, distribution, purchase, and sale of electric energy and related utility services to approximately 1.14 million residential, commercial, and industrial customers located within 13 counties and 249 municipalities of the State of New Jersey. JCP&L owns, operates, and maintains 2,598 circuit miles of transmission lines, substations and other transmission facilities in Northern and Central New Jersey.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. JCP&L is filing with FERC a transmission formula rate that will be used to calculate an annual transmission requirement that will compensate JCP&L for the costs of owning and operating its transmission facilities in New Jersey. The purpose of my testimony is to describe the proposed formula rate and explain and support the reasonableness of it. In addition, I describe JCP&L's proposed formula rate protocols that will be used to implement the formula rate, and explain how these protocols comply with Commission precedent.

Q. PLEASE DESCRIBE THE EXHIBITS YOU ARE SPONSORING.

A. In addition to my testimony (Exhibit No. JCP-100) and statement of qualifications (Exhibit No. JCP-101), I am sponsoring Exhibit Nos. JCP-102 (Formula Rate), JCP-103 (Formula Rate Protocols), and JCP-104 (Confidential Actuarial Report for FE Corp.).

III. SUMMARY OF TESTIMONY

Q. WHY IS IT REASONABLE FOR JCP&L TO USE A FORMULA RATE TO CALCULATE ITS TRANSMISSION REVENUE REQUIREMENT?

A. JCP&L is proposing to replace the currently-effective stated revenue requirement in Attachment H-4 of the PJM Interconnection Inc. ("PJM") Open Access Transmission Tariff ("OATT") with a forward-looking formula rate to account for JCP&L's transmission system investments in the upcoming years. The use of a forward-looking formula rate instead of a stated rate will allow JCP&L to collect a transmission revenue requirement that is representative of the costs of those investments in the current period, provide greater certainty for cost recovery of capital expenditures to improve its transmission infrastructure, and ensure (by virtue of the true-up mechanism that I will discuss) that customers pay the cost to serve them over the lives of the transmission projects. For these reasons, a forward-looking formula rate will result in wholesale transmission rates that are fair, just, and reasonable on a prospective basis.

Q. PLEASE DESCRIBE THE FORWARD-LOOKING FORMULA RATE REVENUE REQUIREMENT STRUCTURE.

A. The proposed formula rate is forward looking and forecasts JCP&L's projected transmission revenue requirement ("PTRR") for the upcoming rate year, which PJM will include in calculating the transmission rates to be effective each rate year beginning on January 1. A true-up between the PTRR and JCP&L's actual transmission revenue requirements ("ATRR") then will be calculated the following year (cost year plus one) and applied, with interest, as an addition to or subtraction from the subsequent year's PTRR (cost year plus two). This true-up mechanism ensures that customers are not over charged if the ATRR is less than the billed net revenue requirement.

Q. HOW IS THE INTEREST RATE DEVELOPED AND APPLIED?

A. Interest on any true-up shall be based on the interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. § 35.19a; or (ii) the interest rate determined by 18 CFR § 35.19a, if JCP&L does not have short-term debt. Interest rates will be used to calculate the time value of money for the period that the true-up exists. The interest rate to be applied to the true-up will be determined using the average rate for the twenty (20) months preceding September 1 of the current year.

The interest rate is then applied to the entire rate term's true-up adjustment, from the initial collection period term (cost year), held during year one (cost year plus one), and then returned (or collected) prorated during year three (cost year plus two).

Q. PLEASE PROVIDE AN OVERVIEW OF JCP&L'S FORMULA RATE.

A. The formula rate consists of two components, each of which will be included as part of Attachment H-4 to the PJM OATT. The first consists of the formula rate (Attachment H-4A, attached as Exhibit No. JCP-102), which is used to determine JCP&L's revenue requirement. The second component consists of the formula rate protocols (Attachment H-4B, attached as Exhibit No. JCP-103).

Q. PLEASE SUMMARIZE HOW THE FORMULA RATE WORKS.

A. The formula rate identifies the data to be used in the revenue requirement calculation and the several equations used in this calculation. In order to calculate JCP&L's revenue requirement each year, the formula rate template will be populated with data that, for purposes of the ATRR, comes mostly from JCP&L's FERC Form 1 filed with the Commission, and, for purposes of the PTRR, comes mostly from JCP&L's budget. When the data are input into the formula rate template, various equations in the template are applied to calculate JCP&L's revenue requirement for the PTRR and ATRR.

Q. PLEASE PROVIDE AN OVERVIEW OF JCP&L'S FORMULA RATE PROTOCOLS.

A. JCP&L's protocols provide the procedures for review and challenge of JCP&L's rates that result from application of the formula rate for a particular year. More specifically, they describe how the formula rate will be updated each year, provide what the review procedures will be, explain how customer challenges will be resolved, and state how any changes to the annual rate restatement (i.e., the annual charges update) will be implemented.

IV. FORMULA RATE

Q. PLEASE DESCRIBE IN DETAIL THE ACTUAL APPLICATION OF THE PROPOSED FORMULA RATE.

A. Page 1, lines 1-10 of the formula rate (Exhibit No. JCP-102), summarize the annual revenue requirement calculations for JCP&L's transmission facilities and approved regional transmission expansion planning ("RTEP") projects in PJM. Line 1 is the gross revenue requirement carried forward from page 3, line 42. Lines 2-6 are revenue credits that the calculation of the revenue requirement removes because a separate revenue stream exists for these particular components. Similarly, line 7 is the calculated revenue, from Attachment 11, associated with Transmission Enhancement Charges ("TEC") Schedule 12 RTEP-projects determined by PJM to benefit customers, partially or wholly outside of the JCP&L zone and thus must be removed from the NITS revenue requirement. Line 8 is the total of all revenue credits, which is reduced from the gross revenue requirement in line 1. Line 9 is the true-up adjustment with interest, calculated on Attachment 13. Line 10 is the Network Integration Transmission Service ("NITS") net revenue requirement for the year, which is used to calculate the corresponding NITS rate, found on line 13. Lines 11 and 12 provide the zonal peaks for the JCP&L zone in which JCP&L operates. Lines 14 through 18 provide on- and off-peak point-to-point rates that derive from the calculated revenue requirement.

Pages 2 through 3 of Exhibit No. JCP-102 calculate the traditional net revenue requirement for all PJM transmission facilities for JCP&L. The gross revenue requirement, on page 3, line 42 is the sum of operation and maintenance expense ("O&M"), depreciation expense, taxes other than income taxes, income taxes and return on rate base. The underlying cost data reflect JCP&L's costs (as estimated and trued-up the following year to data reported in Form 1 and other inputs to the formula).

Exhibit No. JCP-102 also includes, beginning on page 4, a listing of "Supporting Calculations and Notes" that are inputs to the basic formula on pages 1 through 3, specifically: (a) the Transmission Plant allocator (TP) (page 4, lines 1-5); (b) the Transmission Expense allocator (TE) (page 4, lines 6-11); (c) the Wages & Salaries allocator (W/S) (page 4, lines 12-16); the Common Plant allocator (CE) (page 4, lines 12-

20) and (d) the capital structure and overall Rate of Return (R) (page 4, lines 21-25). These supporting calculations and notes are followed by explanatory notes on page 5.

Pages 1 through 3 generally have the same presentation of data: each line of the formula consists of five columns of information or data (in addition to the "Line No." column):

(1) a description of the cost item or formulaic result of the calculation on the line;

(2) the source of the input data (a FERC Form 1 page number or an attachment), or an instruction describing a calculation (e.g., "Sum lines 5 to 9") along with a reference to any applicable notes;

(3) the actual Total Company data input or sum of the data (shaded areas represent direct inputs whereas non-shaded areas include a calculation or a link to a corresponding attachment).

(4) the allocator or functionalization factor applicable to the Total Company value; and

(5) the transmission-related amount obtained by applying the allocator or functionalization factor to the Total Company value.

Q. PLEASE DESCRIBE HOW RATE BASE IS CALCULATED BY THE FORMULA RATE.

A. As set out on page 2, lines 1-6, Transmission Plant is allocated to transmission by the TP allocator (discussed above), and General and Intangible Plant are functionalized to transmission by the Wages & Salary (W/S) allocator. The Accumulated Depreciation associated with transmission and general and intangible plant are similarly functionalized (lines 7-12).

Net transmission plant, property and equipment balances are calculated at lines 13-18. All plant balances are calculated based on 13-month averages, the details of which are developed on Attachment 3 (gross plant) and Attachment 4 (accumulated depreciation).

Adjustments to Rate Base include Accumulated Deferred Income Taxes ("ADIT") (line 19-23), unfunded reserves (lines 24-25), construction work in progress ("CWIP") (line 26), and abandoned plant (line 27). ADIT is calculated on Attachments 5 through 5c, unfunded reserves are calculated on Attachment 14, abandoned plant is calculated on Attachment 16 and CWIP is calculated on Attachment 17. Each of these adjustments to rate base is carried over to page 2 lines 19 to 23 for ADIT, lines 24 and 25 for unfunded reserves, line 27 for abandoned plant and line 26 for CWIP .

CWIP and abandoned plant at lines 26-27 reflect the 13-month average balances as shown on each item's corresponding attachment. CWIP and abandoned plant, on lines 26 and 27, respectively, will remain zero and not be populated with amounts without approval of such recovery through a separate filing at FERC.

Land Held for Future Use is specified on Attachment 14 and included at line 29.

Working Capital (lines 30-34) consists of three elements: (1) Cash Working Capital ("CWC") calculated as one-eighth of total O&M expenses (minus any amortization of regulatory assets); (2) Materials & Supplies; and (3) Prepayments (minus pre-paid income taxes).

Q. PLEASE DISCUSS HOW THE ADIT BALANCES ARE INCLUDED IN THE FORMULA RATE.

A. Deferred income taxes arise when items are included in taxable income in different periods than they are included in book income such as accelerated depreciation expense for tax purposes.

Q. DOES THE ADIT CALCULATION COMPLY WITH THE IRS' NORMALIZATION RULES?

A. Yes. Attachment 5b and Attachment 5c "pro-rate" quarterly projected changes to ADIT to comply with IRS normalization rules for future-looking test periods, as interpreted by IRS published private letter rulings. JCP&L's ADIT calculation follows the Commission-approved approach taken by Dominion Virginia Power. *See PJM Interconnection, L.L.C. and Va. Elec. & Power Co.*, 154 FERC ¶ 61,126 at PP 8, 18 (2016).

Q. PLEASE DISCUSS THE INCLUSION OF O&M EXPENSES IN THE FORMULA RATE.

A. Total transmission O&M expense shown at page 3, line 14, consists of Transmission expense (line 1) functionalized by the TE allocator, plus Administrative & General ("A&G") expense functionalized to transmission.

The formula (at lines 2-4) removes LSE expenses included in transmission O&M accounts, Account 566 (Miscellaneous Expenses) values, which are included on lines 11-12 as discussed below, and any Account 565 (Transmission by Others) values.

Lines 11 and 12 provide a break out of Account 566 values to show the amortization of regulatory assets that will be amortized to Account 566, if any, consistent with FERC precedent. JCP&L is not filing for the recovery of any regulatory assets in this case, but reserves the right to do so in a future Section 205 filing. Consistent with FERC precedent, Account 566 expenses are recoverable through the formula rate. Lines 11 and 12 are simply provided to ensure that any amortization of regulatory assets is not included as a component within cash working capital.

Total company A&G expense (as adjusted for FERC Annual Fees, Regulatory Commission Expense, Electric Power Research Institute ("EPRI") dues, and non-safety General Advertising Expense) is functionalized to Transmission by the W/S allocator.

Regulatory Commission Expenses related to transmission are included on line 8.

Common expenses (if any) are included at line 10.

The post-employment benefits other than pensions ("PBOP") rates of JCP&L are supported by an actuarial report performed by an independent third party (*see* Exhibit No. JCP-104 at 6). JCP&L employees and employees of its affiliates will provide services to JCP&L on an at-cost basis directly or through service agreements. Accordingly, the stated rate inputs for PBOP in JCP&L's formula derive from the PBOP rates for JCP&L and all of its affiliates. As reflected on Attachment 6, the stated PBOP rates per dollar of labor expended on the transmission facilities can only be changed pursuant to a separate section 205 or 206 filing. This treatment is consistent with the treatment approved in *Trans-Allegheny Interstate Line Co.*, 124 FERC ¶ 61,075 (2008).

Q. PLEASE DISCUSS HOW THE FORMULA RATE INCLUDES DEPRECIATION AND AMORTIZATION EXPENSE.

A. Total Transmission Depreciation and Amortization Expense is shown on page 3, line 19. It is the sum of transmission plant depreciation and amortization expense (line 15), plus general plant depreciation and intangible plant amortization (line 16), functionalized to transmission. Consistent with the functionalization of general and intangible plant, G&I depreciation is functionalized to transmission by the W/S allocation factor.

The depreciation rates used to calculate the transmission plant depreciation expense are included in Attachment 9 to the formula rate. These rates are supported by a depreciation study performed by Mr. John Spanos that is being submitted by JCP&L as Exhibit No. JCP-300.

Common plant (line 17), if any, is functionalized to transmission by the CE allocation factor (developed on page 4 as the transmission plant percent of total plant times the transmission W&S allocator).

The formula also includes a provision (line 18) for including the amortization of any unrecovered abandoned plant costs for which JCP&L receives Commission approval in a separate filing. Such amortization is directly assigned to the Transmission function.

Q. PLEASE DISCUSS HOW THE FORMULA RATE DEVELOPS TAXES OTHER THAN INCOME TAXES.

A. Taxes other than income taxes (Other Taxes) are functionalized to transmission and specified at lines 20-27 of page 3. Labor-related taxes are functionalized by the W/S allocator (lines 20-21). Real and personal property, miscellaneous other taxes and payments in lieu of taxes (if any) (lines 23, 25 and 26) are functionalized by the Gross Plant (GP) allocator. Gross receipts are excluded (line 24).

Q. PLEASE DISCUSS HOW THE FORMULA RATE INCLUDES INCOME TAXES ON PAGE 3 OF ATTACHMENT H-4A.

A. Federal and state income taxes (line 38) are developed consistent with the return on rate base calculated at line 39.

The tax components are Federal Income Tax Rate (“FIT”), State Income Tax Rate (or Composite) (“SIT”), and the percent (p), if any, of federal income tax deductible in the calculation of state income tax (lines 28-29). These components are specified in Note K. The composite federal/state income tax rate (T), is calculated on line 28, where:

$$T = 1-\{[(1-SIT) * (1-FIT)] / (1-SIT * FIT * p)\}.$$

The tax multiplier, 1/(1-T), is calculated on line 30.

The investment tax credit ("ITC") adjustment, permanent differences and AFUDC equity tax adjustments, and the Excess (Deficient) Deferred Income Tax adjustment are shown at lines 31 through 33, respectively. The respective revenue effects of these adjustments (lines 35-37) are calculated by multiplying each of them by the tax multiplier at line 30, the products of which are functionalized to transmission by multiplying by the Net Plant (NP) allocator for the ITC adjustment and directly assigned for permanent differences and AFUDC equity and excess (deficient) deferred income taxes.

The income tax component is calculated at line 34 as the product of (T/1-T) times the portion of the investment return that is taxable (which is 1 minus the weighted debt cost rate, divided by the overall rate of return) times the investment return (line 39). The weighted debt cost rate is calculated at page 4, line 22, and the overall rate of return is calculated at page 4, line 25.

Total income taxes (line 38) are the summation of the income tax component (line 34) and the three adjustments (lines 35-37).

Q. HOW DOES THE INCOME TAX CALCULATION ACCOUNT FOR THE TAX CUTS AND JOBS ACT ("TCJA") REGARDING THE TIMING OF THE RETURN OF EXCESS DEFERRED TAXES?

A. The TCJA reduced the federal corporate tax rate from a maximum of thirty-five percent under the graduated rate structure, to a flat twenty-one percent rate, effective January 1, 2018. The reduction in the federal corporate tax rate results in excess ADIT ("EDIT") balances for JCP&L and many other transmission owners. To address this on an on-going basis, the formula rate includes at line 33 an Excess/Deficient Deferred Income Tax adjustment. The EDIT calculations on Attachments 15 and 15a support the EDIT adjustment on line 33. By adding these items, JCP&L has adopted the general approach that the Commission accepted in 2018 to resolve this same issue for International Transmission Company d/b/a ITC Transmission, Michigan Electric Transmission Company, LLC, and ITC Midwest LLC (the "ITC Companies") in Docket No. ER16-208, and for Ameren Services Company ("Ameren") in Docket No. ER17-2323. The approach is also consistent with the principles set forth by the Commission in its Notice of Proposed Rulemaking ("NOPR") issued November 15, 2018 in Docket No. RM19-5-00 on Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes.

Q. HOW DOES JCP&L AMORTIZE EXCESS OR DEFICIENT ADIT?

A. For depreciation differences protected by the Internal Revenue Code, and for unprotected plant differences, JCP&L amortizes excess or deficient ADIT over the life of the underlying asset using the Average Rate Assumption Method for all Protected Property and Non-Protected Property. JCP&L amortizes Non-Protected, Non-Property by 10 years and Protected, Non-Property by 35 years.

Q. PLEASE DISCUSS HOW THE FORMULA DEVELOPS THE RETURN ON RATE BASE.

A. Return on Rate Base (line 39) is the product of rate base (page 2, line 35) times R (page 4, line 25). R, the overall rate of return, is the sum of the weighted cost rates for long-term debt ("LTD"), preferred stock, and common equity calculated at page 4, lines 22 through 25.

The LTD cost rate (page 4, line 22) is derived from Attachment 10, which is based on the total weighted average debt cost.

The total return on common equity ("ROE") is 10.8%—which consists of a base ROE of 10.3% plus a 50 basis point adder for JCP&L's participation in PJM. This ROE is supported by the testimony of Mr. Adrien McKenzie, Exhibit No. JCP-200. The ROE will not change absent a separate proceeding under Section 205 or 206 of the Federal Power Act ("FPA").

The preferred stock cost rate (if any) will be calculated on page 4, line 23, consistent with standard FERC rate making.

The common equity of the capital structure is shown at line 24.

Total capitalization (page 4, line 25) is the sum of LTD, preferred stock and common equity. LTD (line 22), preferred stock (line 23) and common stock (line 24) divided by total capitalization give the capitalization shares shown on those lines, respectively.

Q. WILL THERE BE ANY INCENTIVE ROE TREATMENT FOR JCP&L?

A. JCP&L is seeking authorization for a 50 basis point ROE incentive for participation in the PJM RTO, as authorized by the Commission. *See* testimony of Mr. Adrien McKenzie, Exhibit No. JCP-200. Otherwise, JCP&L is not seeking any other ROE incentives at this time. JCP&L reserves the right to request incentives at an appropriate time in the future and the formula rate accommodates any specific incentives for RTEP projects that the Commission may grant at a later date.

Q. PLEASE DESCRIBE EACH OF THE WORKSHEETS THAT SUPPORT ATTACHMENT H-4.

A. Attachment 1 calculates the Schedule 1A Rate. Attachment 2 is a placeholder and calculates an incentive ROE if one were to exist for a specific project in the future. Attachments 3 Gross Plant and 4 Accumulated Depreciation calculate the 13-month average of net plant. Attachments 5 to 5c calculate the ADIT current period activity along with adjustments. Attachment 6 calculates the PBOP adjustment by using a fixed rate.

Attachment 7 calculates the taxes other than income taxes. Attachment 8 calculates the capital structure using a 13-month average. Attachment 9 sets forth the depreciation rates for each FERC account and other stated values, including ROE and PBOP. Attachment 10 calculates the weighted average rate of long-term outstanding debt. Attachments 11 to 12 calculate the TEC credit for any RTEP project that benefits customers outside of the JCP&L zone. Attachments 13 and 13a calculate the NITS and TEC true-up from a prior rate year and will only be populated within the PTRR in the year refunded or charged to customers. Attachment 14 calculates the other rate base items using a beginning/ending average. Attachment 15 includes the permanent differences and AFUDC equity amortization and 15a calculates the current period amortization of the excess/deficient deferred income taxes. Attachment 16, 17, and 19 are placeholders for abandoned plant, CWIP, and regulatory asset, respectively, all of which must be approved by the Commission in a separate FPA Section 205 proceeding. Attachment 18 includes the current federal and state income tax rates. Attachment 20 includes detail of transmission Operating and Maintenance as well as transmission Administrative and General expenses.

Q. CAN YOU PROVIDE AN EXAMPLE, USING REAL DATA, OF HOW THE FORMULA RATE CALCULATES AN ATRR?

A. Yes. In his testimony, Mr. Michael Falen, Director in Transmission System Services, is sponsoring cost of service Statement BK, which provides calculations of JCP&L's transmission rate using the proposed formula rate based on projected data for calendar year 2020. *See* Exhibit No. JCP-402 at 48 to 89.

Q. WHAT IS JCP&L'S PTRR FOR CALENDAR YEAR 2020 UNDER THE PROPOSED FORMULA RATE?

A. As shown in Exhibit No. JCP-402, the PTRR for calendar year 2020 is approximately \$147.5 million of NITS revenue and approximately \$22.0 million of TEC revenue. *See* Exhibit No. JCP-402 at page 45, line 10 and line 7, respectively. In accordance with the formula rate, these amounts will be updated to reflect actual 2020 costs through the subsequent 2020 ATRR.

Q. PLEASE EXPLAIN WHY THE PROPOSED FORMULA RATE IS JUST AND REASONABLE.

A. The proposed formula rate is similar in both form and substance to multiple other forward-looking transmission formula rates employed by other transmission owners in the PJM region. *See, e.g.*, *PJM Interconnection, L.L.C. and Potomac Elec. Power Co.*, 167 FERC ¶ 61,192 (2019); *NextEra Energy Transmission MidAtlantic, LLC*, 161 FERC ¶ 61,141 (2017); *PJM Interconnection, L.L.C. and Northeast Transmission Development, LLC,* 155 FERC ¶ 61,097; *NextEra Transmission West, LLC*, 154 FERC ¶ 61,009 (2016), *order on compliance and hearing procedures*, 156 FERC ¶ 61,095 (2016); *Midwest Power Transmission Ark., LLC*, 152 FERC ¶ 61,210 (2015); *Kanstar Transmission, LLC*, 152 FERC ¶ 61,209 (2015), *reh'g denied*, 155 FERC ¶ 61,167 (2016). JCP&L plans to invest in the PJM footprint and the proposed formula rate allows JCP&L to collect revenues representative of the transmission costs incurred in the current period, provides for greater certainty for cost recovery of capital expenditures to improve the transmission infrastructure, and ensures that customers pay the cost to serve them over the lives of the facilities.

Q. DO THE INITIAL RATES INCLUDE A TRUE-UP ADJUSTMENT?

A. No; for the initial year, the True-Up Adjustment is zero. Because this filing represents the first year of a transition from stated rates to a formula rate, there is no historical rate year that qualifies for a True-Up Adjustment pursuant to the proposed Protocols. If this filing is made effective in 2020, the true-up will first be calculated in 2021, and will be adjusted as described in the Protocols, and will be included in the PTRR for 2022. Until that time, the True-Up Adjustment will remain zero.

V. JCP&L'S FORMULA RATE PROTOCOLS

Q. PLEASE DESCRIBE JCP&L'S FORMULA RATE PROTOCOLS.

A. JCP&L's protocols provide the procedures for review and challenge of JCP&L's charges that result from application of the formula rate to data for a particular year. The protocols include a requirement to post fully functional workable and populated formulas in Microsoft Excel format with all formulas intact. The protocols provide for annual updates that are publicly posted for interested parties and informational filings to the Commission that will contain sufficient support for all inputs so that interested parties can verify that each input is consistent with the requirements of the formula. The review procedures provide for transmission customers, state commissions, and other interested parties to review and submit a written preliminary challenge to specific items included in the populated formula rate. These interested parties also may serve reasonable information requests on JCP&L. JCP&L will make a good faith effort to respond to these requests within 15 business days. If the parties have not been able to resolve any such challenge, the party bringing the challenge may file a formal challenge with the Commission under FPA section 206. These procedures do not limit in any way JCP&L's right to file, pursuant to FPA section 205, changes to the formula rate or any of its inputs requiring a section 205 filing under the protocols, or the right of any other party to file a complaint requesting such changes under FPA section 206 at any time. The Protocols permit JCP&L, however, to make a limited FPA section 205 filing at any time to change the stated amortization and depreciation rates, PBOPs, or make any changes required in a final rulemaking associated with excess/deficient deferred income taxes.

Q. PLEASE EXPLAIN WHY JCP&L'S FORMULA RATE PROTOCOLS ARE REASONABLE.

A. JCP&L's protocols are based on the protocols for forward looking transmission formula rates accepted by the Commission for use by transmission owners in the Midcontinent Independent System Operator, Inc. ("MISO") region. *See Midwest Indep. Transmission Sys. Oper., Inc*., 139 FERC ¶ 61,127 (2012), *order on investigation*, 143 FERC ¶ 61,149 (2013), *order on reh'g*, 146 FERC ¶ 61,209, *order on compliance filing*, 146 FERC ¶ 61,212 (2014) ("*MISO*"). Although these protocols were adopted for MISO and were not explicitly made applicable to PJM, where JCP&L is located, the Commission has stated in a number of orders that the protocols represent the standard for formula rate protocols in other RTOs. *See, e.g.*, *Republic Transmission, LLC,* 167 FERC ¶ 61,215 at P 18 (2019); *Midcontinent Indep. Sys. Oper., Inc. and Pioneer Transmission, LLC*, 164 FERC ¶ 61,155 at P 65 (2018).

JCP&L's protocols also include additional procedures that the Commission has required since the time that it approved the MISO protocols, such as provisions governing the allocation of costs among affiliates. *See PJM Interconnection, L.L.C. and Northeast Transmission Development, LLC*, 155 FERC ¶ 61,097 at P 127 (2016) ("*PJM/NETD*"). Further, JCP&L has borrowed from the protocols approved by the Commission for use by

Mid-Atlantic Interstate Transmission, LLC ("MAIT")—an affiliate of JCP&L that also is wholly-owned by FirstEnergy and located in PJM. MAIT's protocols were accepted by the Commission by letter order on May 21, 2018. *PJM Interconnection, L.L.C. and Mid-Atlantic Interstate Transmission, L.L.C.*, 163 FERC ¶ 61,131 (2018). The MAIT protocol provisions that JCP&L has incorporated are consistent with the *MISO* protocols approved by the Commission.

Q. ARE THERE ANY DIFFERENCES BETWEEN THE JCP&L PROTOCOLS AND THE PROTOCOLS APPROVED IN *MISO* THAT YOU WOULD LIKE TO POINT OUT?

A. While the protocols in *MISO* provide for a posting of the PTRR on September 1 of each year, it would be impractical for JCP&L to follow such a date. The timing of FirstEnergy's corporate budget process, including, most importantly, the identification of the projected affiliate cost allocations, makes it extremely difficult for JCP&L to complete the PTRR any earlier than the end of October. JCP&L is proposing a PTRR posting date of October 31 to accommodate this reality. To ensure that there will be no prejudice to Interested Parties, JCP&L has extended the deadlines for discovery, Preliminary Challenges, and Formal Challenges to be consistent with the timeframes set forth in the MISO protocols.

The proposed protocols also add two features that were not present in the *MISO* protocols. First, the proposed protocols add language pertaining to affiliate cost allocation that the Commission deemed to be necessary in its order in *PJM/NETD*, 155 FERC ¶ 61,097. Second, the proposed protocols also reserve JCP&L's right to make limited, single-issue FPA section 205 filings to change certain values that are included as stated inputs to the formula rate, namely: (i) depreciation rates or amortization periods; (ii) post-employment benefits other than pensions charges; or (iii) changes required in a final FERC rulemaking associated with excess/deficient deferred income taxes. The Commission has accepted such single-issue filings in prior cases. *See, e.g.*, *PJM Interconnection, L.L.C. and PPL Elec. Utils. Corp.*, 167 FERC ¶ 61,083 (2019) (single issue filing of ADIT-related changes); *Virginia Elec. & Power Co.*, Docket No. ER19-1543-000 (Letter Order issued May 7, 2019) (single issue filing of post-employment benefits other than pension charges); *Southwest Power Pool, Inc.*, 167 FERC ¶ 61,202 (2019) (single issue filing of depreciation changes by Mid-Kansas Electric Company, Inc. and Sunflower Electric Power Corporation).

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit No. JCP-100

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jersey Central Power & Light Company) Docket No. ER20-___-000

DECLARATION OF ROGER D. RUCH

I, Roger D. Ruch, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on October 30, 2019.

/s/ Roger D. Ruch
Roger D. Ruch

ROGER D. RUCH

Education, Professional Background and Relevant Experience

Mr. Ruch holds a Bachelor of Science in Business Administration degree with a major in Accounting from The Ohio State University. He is a certified public accountant in the State of Ohio and a member of both the American Institute of Certified Public Accountants and the Ohio Society of Certified Public Accountants. Prior to joining FirstEnergy in 1999, he was employed by Coopers & Lybrand LLP for eleven years and Sealy Mattress Company for two and a half years.

Mr. Ruch has been employed by affiliates of FirstEnergy Corp. for over 20 years in various accounting, finance, operations, market policy and regulatory positions within FirstEnergy Service Company (the "Service Company") and FirstEnergy Solutions ("FES"). From 1999 through 2007 Mr. Ruch held the positions of Controller and then CFO of FES' Facilities Services Group and the Controller of FES. From 2007 through 2010 Mr. Ruch was a Director in the Commodity Operations Group of FES and from 2011 through early 2012 was the Director of FERC & RTO Competitive Market Policies for FES.

In April 2012, Mr. Ruch joined the Rates and Regulatory Affairs organization of the Service Company as the Director of Rates Support. In his current role in the Rates Support Group, he is responsible for the regulatory requirements associated with the transmission businesses within FirstEnergy including the stand-alone transmission companies American Transmission Systems, Incorporated, Mid-Atlantic Interstate Transmission, LLC, Trans-Allegheny Interstate Line Company, and Potomac-Appalachian Transmission Highline, LLC, as well as the transmission businesses resident in FirstEnergy Utility Operating Companies Jersey Central Power & Light Company and Potomac Edison Company, West Penn Power Company and Monongahela Power Company. With respect to the transmission companies, the Rates Support Group administers formula rates and associated Federal Energy Regulatory Commission filings, interactions with interested parties in accordance with established protocols, including conducting open meetings to review and explain annual formula rate filings. The Rates Support Group is also responsible for oversight and the analytical support required for other regulatory filings, primarily at the federal level as well as support to the stakeholder process at PJM Interconnection, L.L.C. with respect to rate-related activities and initiatives.

ATTACHMENT H-4B

Jersey Central Power & Light Company

Formula Rate Implementation Protocols

ANNUAL TRUE-UP, INFORMATION EXCHANGE, AND CHALLENGE PROCEDURES

Definitions

"Actual Transmission Revenue Requirement" or "ATRR" means the actual net transmission revenue requirement calculated and posted on the PJM website no later than June 10 of each year subsequent to calendar year 2020 for the immediately preceding calendar year in accordance with JCP&L's Formula Rate and based upon JCP&L's actual costs and expenditures.

"Annual Update" means JCP&L's ATRR for the preceding calendar year, as well as the True-up for the prior Rate Year, as posted on or before June 10 of each year.

"Formal Challenge" means a written challenge to an Annual Update or Projected Transmission Revenue Requirement submitted to the Federal Energy Regulatory Commission (the "Commission" or "FERC") as provided in Section IV below.

"Formula Rate" means the collection of formulas and worksheets, unpopulated with any data, included as Attachment H-4A of the PJM Tariff.

"Interested Parties" include, but are not limited to, customers under the PJM Tariff, state utility regulatory commissions, the Organization of PJM States, Inc., consumer advocacy agencies, and state attorneys general.

"PJM Tariff" means the Open Access Transmission Tariff of the PJM Interconnection, L.L.C.

"Preliminary Challenge" means a written challenge to the Annual Update or Projected Transmission Revenue Requirement submitted to JCP&L as provided in Section IV below.

"Projected Transmission Revenue Requirement" or "PTRR" means the projected net transmission revenue requirement calculated for the forthcoming Rate Year, as well as, where applicable, the most recently calculated True-up, with interest, to be posted on the PJM website no later than October 31 of each year for rates effective the next calendar year starting January 1.

"Protocols" means these Protocols, included as Attachment H-4B of the PJM Tariff).

"Publication Date" means the date on which the Annual Update is posted.

"Rate Year" means the twelve consecutive month period that begins on January 1 and continues through December 31.

"True-up" means the difference between the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) and the ATRR for the same Rate Year, which shall be provided in the Annual Update on or before June 10 of the year subsequent to the Rate Year. The True-up will be a component of the PTRR.

Section I. Applicability

The following procedures shall apply to the Jersey Central Power & Light Company ("JCP&L") calculation of its Actual Transmission Revenue Requirement, True-up, and Projected Transmission Revenue Requirement.

Section II. Annual Update and Projected Transmission Revenue Requirement

A. On or before June 10 of each year subsequent to calendar year 2020, JCP&L shall determine its Annual Update for the immediately preceding calendar year under Attachment H-4A and Section VII of these Protocols, including calculation of the True-up to be included in JCP&L's PTRR for the subsequent Rate Year.

B. On or before June 10 of each year subsequent to calendar year 2020, JCP&L shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website. Within two (2) days of such posting, JCP&L shall provide notice of such posting via an e-mail exploder list.

C. On or before October 31, 2020, and on or before each subsequent October 31, JCP&L shall provide the PTRR to PJM and cause such information to be posted on the PJM website, in both a Portable Document Format ("PDF") and fully-functioning Excel file, and within two (2) days of posting of the PTRR, JCP&L shall provide notice of such posting via an e-mail exploder list.

D. If the date for posting the Annual Update or PTRR falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual Update occurs shall be that year's Publication Date. Any delay in the Publication Date or in the posting of the PTRR will result in an equivalent extension of time for the submission of information requests discussed in Section III of these Protocols.

E. The ATRR shall:

1. Include a workable data-populated version of the Formula Rate template and underlying work papers in Excel format with all formulas and links intact;

2. Be based on JCP&L's FERC Form No. 1 for the prior calendar year;

3. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the ATRR that are not otherwise available in the FERC Form No. 1, subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC's Model Protective Order;

4. Provide sufficient information to enable Interested Parties to replicate the calculation of the ATRR results from the FERC Form No. 1;

5. Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1;

6. Identify and, to the extent not explained in a worksheet included in the ATRR, explain, all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in the FERC Form No. 1;

7. Provide underlying data for Formula Rate inputs that provide greater granularity than is required for the FERC Form No. 1;

8. With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

    a. Identify any Accounting Change, including:

        i. the initial implementation of an accounting standard or policy;

        ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

        iii. correction of errors and prior period adjustments that affect the ATRR and True-up calculation;

        iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the ATRR at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the ATRR; and

d. Provide, for each item identified pursuant to items II.E.8.a - II.E.8.c above, a narrative explanation of the individual impact of such change on the ATRR; and

9. Include for the applicable Rate Year the following information related to affiliate cost allocation: (A) a detailed description of the methodologies used to allocate and directly assign costs between JCP&L and its affiliates by service category and function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; and (B) the magnitude of such costs that have been allocated or directly assigned between JCP&L and each affiliate by service category or function.

F. The Projected Transmission Revenue Requirement shall:

1. Include a workable data-populated version of the Formula Rate template and underlying work papers in Excel format with all formulas and links intact;

2. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the PTRR;

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the PTRR;

4. With respect to any Accounting Change:

a. Identify any Accounting Change, including:

i. the initial implementation of an accounting standard or policy;

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. correction of errors and prior period adjustments that affect the PTRR calculation;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the PTRR at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the PTRR; and

d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these Protocols, a narrative explanation of the individual impact of such change on the PTRR.

G. JCP&L shall hold an open meeting among Interested Parties ("Annual Update Meeting"), to be conducted via Internet webcast, no earlier than ten (10) business days following the Publication Date and no later than July 10. No fewer than seven (7) days prior to such Annual Update Meeting, JCP&L shall provide notice on PJM's website of the time and date of the Annual Update Meeting, and shall provide notice of the posting via an e-mail exploder list. The Annual Update Meeting shall: (i) permit JCP&L to explain and clarify its ATRR and True-up; and (ii) provide Interested Parties an opportunity to seek information and clarifications from JCP&L about the ATRR and True-up.

H. JCP&L shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting"), to be conducted via Internet webcast, no earlier than five (5) business days following the posting of the PTRR (as described in Section II.C of these Protocols) and no later than November 30. No fewer than five (5) days prior to such Annual Projected Rate Meeting, JCP&L shall provide notice on PJM's website of the time and date of the Annual Projected Rate Meeting, and shall provide notice of the posting via an e-mail exploder list. The Annual Projected Rate Meeting shall: (i) permit JCP&L to explain and clarify its PTRR and (ii) provide Interested Parties an opportunity to seek information and clarifications from JCP&L about the PTRR.

Section III. Information Exchange Procedures

Each Annual Update and PTRR shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until January 15 following the Publication Date (unless such period is extended with the written consent of JCP&L or by FERC order) to serve reasonable information and document requests on JCP&L ("Information Exchange Period"). If January 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

1. the extent or effect of an Accounting Change;
2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these Protocols;
3. the proper application of the Formula Rate and procedures in these Protocols;
4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the ATRR or PTRR;
5. the prudence of actual costs and expenditures;
6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or
7. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

The information and document requests shall not be directed to ascertaining whether the Formula Rate is just and reasonable.

B. JCP&L shall make a good faith effort to respond to any information and document request within fifteen (15) business days of receipt of such request. JCP&L shall respond to all information and document requests by no later than February 25 following the Publication Date, unless the Information Exchange Period is extended by JCP&L or FERC.

C. JCP&L will serve all information requests from Interested Parties and JCP&L's response(s) to such requests upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such information requests or responses, as needed, under non-disclosure agreements that are based on FERC's Model Protective Order.

D. JCP&L shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any proceeding addressing JCP&L's Annual Update or PTRR, and such responses may be included in any Formal Challenge or other submittal addressing JCP&L's Annual Update or PTRR.

Section IV. Challenge Procedures

A. Interested Parties shall have until March 31 following the Publication Date (unless such period is extended with the written consent of JCP&L or by FERC order) ("Review Period"), to review the inputs, supporting explanations, allocations and calculations and to notify JCP&L in writing, which may be made electronically, of any specific Preliminary Challenges to the Annual Update or PTRR. If the final day of the Review Period falls on a holiday recognized by FERC, the deadline for submitting all Preliminary Challenges shall be extended to the next business day. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update or PTRR shall bar pursuit of such issue with respect to that Annual Update or PTRR under the challenge procedures set forth in these Protocols, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update or PTRR. This Section IV.A in no way shall affect a party's rights under Federal Power Act ("FPA") section 206 as set forth in Section IV.I of these Protocols.

B. Preliminary Challenges shall be subject to the resolution procedures and limitations in this Section IV and shall satisfy all of the following requirements.

1. A party submitting a Preliminary Challenge to JCP&L must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge.

2. JCP&L shall make a good faith effort to respond to any Preliminary Challenge within twenty (20) business days of written receipt of such challenge.

3. JCP&L, and where applicable, PJM, shall appoint a senior representative to work with each party that submitted a Preliminary Challenge (or its representative) toward a resolution of the challenge.

4. If JCP&L disagrees with such challenge, JCP&L will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information.

5. No Preliminary Challenge may be submitted after March 31, and JCP&L must respond to all Preliminary Challenges by no later than April 30 unless the Review Period is extended by JCP&L or FERC, or as provided in Section IV.A above.

6. JCP&L will serve all Preliminary Challenges and JCP&L's response(s) to such Preliminary Challenges upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such Preliminary Challenges or responses, as needed, under non-disclosure agreements that are based on the FERC's Model Protective Order.

C. Formal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy all of the following requirements.

1. A Formal Challenge shall:

a. Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or these Protocols;

b. Explain how the action or inaction violates the filed Formula Rate or these Protocols;

c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

(i) the extent or effect of an Accounting Change;

(ii) whether the ATRR or PTRR fails to include data properly recorded in accordance with these Protocols;

(iii) the proper application of the Formula Rate and procedures in these Protocols;

(iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the ATRR or PTRR;

(v) the prudence of actual costs and expenditures;

(vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

(vii) any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the challenged action or inaction;

e. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the challenged action or inaction raised by the Formal Challenge, and, if not, describe why not.

2. Service. Any person filing a Formal Challenge must serve a copy of such Formal Challenge on JCP&L. Service to JCP&L must be simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. A party filing a Formal Challenge shall serve the individual listed as the contact person on JCP&L's Informational Filing required under Section VI of these Protocols.

D. Preliminary and Formal Challenges shall be limited to all issues that may be necessary to determine:

1. the extent or effect of an Accounting Change;

2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these Protocols, or includes data not properly recorded in accordance with these Protocols;

3. the proper application of the Formula Rate and procedures in these Protocols;

4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the ATRR and PTRR;

5. the prudence of actual costs and expenditures included as inputs to the Formula Rate;

6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

7. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.

E. Any changes or adjustments to the ATRR and PTRR resulting from the information exchange and Preliminary Challenge processes that are agreed to by JCP&L will be reported in the Informational Filing required pursuant to Section VI of these Protocols. Any such changes or adjustments agreed to by JCP&L on or before December 1 will be reflected in the PTRR for the upcoming Rate Year. Any changes or adjustments agreed to by JCP&L after December 1 will be reflected in the following year's Annual Update, as discussed in Section V of these Protocols.

F. An Interested Party shall have until June 1 following the Review Period (unless such date is extended with the written consent of JCP&L to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with FERC, which shall be served on JCP&L on the date of such filing as specified in Section IV.C.2 above. A Formal Challenge shall be filed in the same docket as JCP&L's Informational Filing discussed in Section VI of these Protocols. JCP&L shall respond to the Formal Challenge by the deadline established by FERC. An Interested Party may not pursue a Formal Challenge unless it submitted a Preliminary Challenge on some issue (which may be different from the Formal Challenge issue) during the applicable Review Period.

G. In any proceeding initiated by FERC concerning the Annual Update or PTRR or in response to a Formal Challenge, JCP&L shall bear the burden, consistent with FPA section 205, of proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols, that it followed the applicable requirements and procedures in the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

H. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of JCP&L to file unilaterally, pursuant to FPA section 205 and the regulations thereunder, to change these Protocols, the Formula Rate, or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to FPA section 206.

I. No party shall seek to modify these Protocols or the Formula Rate under the challenge procedures set forth in these Protocols, and the Annual Update and PTRR shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to these Protocols or the Formula Rate will require, as applicable, a FPA section 205 or section 206 proceeding. JCP&L may, at its discretion and at a time of its choosing, make a limited filing pursuant to FPA section 205 to modify stated values in the Formula Rate for (a) amortization and depreciation rates, (b) Post-Employment Benefits Other Than Pensions rates, or (c) to make any changes required in a final FERC rulemaking associated with excess/deficient deferred income taxes. The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.

J. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1 shall first raise the matter with JCP&L in accordance with this Section IV before pursuing a Formal Challenge.

Section V. Changes to Actual Transmission Revenue Requirement or Projected Transmission Revenue Requirement

A. Except as provided in Section IV.E of these Protocols, any changes to the data inputs, including but not limited to revisions to JCP&L's FERC Form No. 1, or as the result of any FERC proceeding to consider the ATRR or PTRR, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the PTRR for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these Protocols.

Section VI. Informational Filings

A. By June 10 of each year, JCP&L shall submit to FERC an informational filing ("Informational Filing") of its PTRR for the Rate Year, including its ATRR and True-up. This Informational Filing must include information that is reasonably necessary to determine:

1. that input data to the Formula Rate are properly recorded in any underlying work papers;
2. that JCP&L has properly applied the Formula Rate and these Protocols;
3. the accuracy of data and the consistency with the Formula Rate of the transmission revenue requirement and rates under review;
4. the extent of Accounting Changes that affect Formula Rate inputs; and
5. the reasonableness of projected costs.

The Informational Filing must also describe any corrections or adjustments made during the period since the Publication Date, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Preliminary Challenge or Formal Challenge procedures.

Finally, the Informational Filing shall include for the applicable Rate Year the following information related to affiliate cost allocation: a detailed description of the methodologies used to allocate and directly assign costs between JCP&L and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; the magnitude of such costs that have been allocated or directly assigned between JCP&L and each affiliate by service category or function; and a copy of any service agreement between JCP&L and any JCP&L affiliate that went into effect during the Rate Year.

Within five (5) days of such Informational Filing, JCP&L shall provide notice of the Informational Filing via an e-mail exploder list and by posting the docket number assigned to JCP&L's Informational Filing on the PJM website, subject to the protection of any confidential information contained in the Informational Filing, as needed, under nondisclosure agreements that are based on FERC's Model Protective Order.

B. Any challenges to the implementation of the Formula Rate must be made through the challenge procedures described in Section IV of these Protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

Section VII. Calculation of True-up

The True-up will be determined in the following manner:

A. As part of the Annual Update for each Rate Year, JCP&L shall determine the difference between the revenues collected by PJM based on the PTRR for the Rate Year (net of the True-up from the prior year) and the ATRR for the same Rate Year based on actual cost data as reflected in its FERC Form No. 1. The True-up will be determined as follows:

i. The ATRR for the previous Rate Year as determined using JCP&L's completed FERC Form No. 1 report shall be compared to the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) for that same Rate Year ("True-up Year") to determine any excess or shortfall in the revenues collected by PJM in the True-up Year. The revenue excess or shortfall determined by this comparison shall constitute the "True-up."

ii. Interest on any True-up shall be based on the interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. § 35.19a; or (ii) the interest rate determined by 18 CFR § 35.19a, if JCP&L does not have short-term debt. Interest rates will be used to calculate the time value of money for the period that the True-up exists. The interest rate to be applied to the True-up will be determined using the average rate for the twenty (20) months preceding September 1 of the current year.

B. JCP&L will post on PJM's website all information relating to the True-up as part of the Annual Update. As provided in Section II.B of these Protocols, JCP&L shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website on or before June 10 of each year subsequent to calendar year 2020.

Section VIII. Formula Rate Inputs

A. Stated inputs to the Formula Rate: For (i) rate of return on common equity; (ii) "Post-Employment Benefits other than Pension" ("PBOP") charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions; and (iii) depreciation and/or amortization rates, the values in the Formula Rate shall be stated values and may be changed only pursuant to a FPA section 205 or section 206 proceeding. These stated-value inputs are specified in Attachment 9 of the Formula Rate.

B. Unpopulated Formula Rate line items: With respect to line items in the Formula Rate that are not currently populated with non-zero numerical values because FERC policy requires prior authorization for recovery of the underlying costs or because, due to the nature of the associated functional activities, such costs are not considered part of JCP&L's transmission-related revenue requirement (but not line items that are zero values in a particular Rate Year for the sole reason that no such costs or revenues were incurred or revenues received or projected to be incurred or received during the Rate Year), such line items shall not be populated with non-zero values except as may be authorized following a FPA section 205 or section 206 proceeding.

Exhibit No. JCP-200

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jersey Central Power & Light Company	**)**	**Docket No. ER20-___-000**

DIRECT TESTIMONY AND EXHIBITS

OF

ADRIEN M. MCKENZIE, CFA

ON BEHALF OF

JERSEY CENTRAL POWER & LIGHT COMPANY

October 30, 2019

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EXHIBITS TO DIRECT TESTIMONY

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JCP-205	ECAPM
JCP-206	Expected Earnings Approach
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JCP-208	Constant Growth DCF Model—Non-Utility Proxy Group

GLOSSARY

Algonquin	Algonquin Power & Utilities, Inc.
CAPM	Capital Asset Pricing Model
Commission	Federal Energy Regulatory Commission
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DCF	discounted cash flow
ECAPM	Empirical Capital Asset Pricing Model
EEI	Edison Electric Institute
Empire District Electric	Empire District Electric Company
EPS	earnings per share
FPA	Federal Power Act
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
IBES	Institutional Brokers' Estimate System
JCP&L or "the Company"	Jersey Central Power & Light Company
MDPSC	Maryland Public Service Commission
MISO TOs	Transmission-owning members of the Midcontinent Independent System Operator, Inc.
Moody's	Moody's Investors Service
NARUC	National Association of Regulatory Utility Commissioners
NETOs	Transmission-owning members of ISO New England
ROE	return on equity
RRA	Regulatory Research Associates, Inc.
RTO	Regional Transmission Organization
S&P	S&P Global Ratings
TCJA	Tax Cuts and Jobs Act
Value Line	The Value Line Investment Survey
VSCC	Virginia State Corporation Commission

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Jersey Central Power & Light Company) Docket No. ER20-___-000

**DIRECT TESTIMONY
OF
ADRIEN M. MCKENZIE, CFA**

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, EMPLOYER, AND TITLE.

A1. My name is Adrien M. McKenzie. My business address is 3907 Red River St., Austin, Texas 78751.

Q2. IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. I am President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q3. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A3. The details of my qualifications and experience are included in Exhibit No. JCP-201 attached to my testimony.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. The purpose of my testimony is to present to the Commission my independent analysis of a just and reasonable return on common equity ("ROE") for Jersey Central Power & Light Company's transmission assets ("JCP&L").

Q5. HOW IS YOUR TESTIMONY ORGANIZED?

A5. I first summarize my conclusions and recommendations regarding a just and reasonable ROE for JCP&L. I then present the technical details of my analyses. Consistent with the

Commission's use of multiple financial models in the Briefing Orders,[1] my analysis includes applications of the DCF model, the ECAPM, the Expected Earnings approach, and the Risk Premium method. These analyses are well-supported and relied upon to evaluate investors' required returns, and, as I demonstrate below, the determination of a just and reasonable ROE for JCP&L should rely on these benchmarks of investor required returns. Finally, I also provide a DCF analysis based on a select group of low risk non-utility firms, which serves as an additional reference point in evaluating a just and reasonable ROE.

II. RETURN ON EQUITY FOR JCP&L

Q6. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A6. This section of my testimony presents the conclusions of my independent evaluation of a just and reasonable ROE for JCP&L. In this regard, I discuss the relationship between the ROE and the preservation of a utility's ability to attract capital. I then summarize the results of my analysis and my conclusion that the base ROE for JCP&L be set at 10.3% plus a 50 basis point adder for RTO participation, for a total ROE of 10.8%. Finally, I address how my recommended ROE meets the Commission's policy goal of supporting investment in electric transmission infrastructure.

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[1] *Coakley v. Bangor Hydro-Elec. Co.*, Order Directing Briefs, 165 FERC ¶ 61,030 (2018) ("Coakley Briefing Order"); *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Order Directing Briefs, 165 FERC ¶ 61,118 (2018) ("MISO Briefing Order") (together, "Briefing Orders").

A. Importance of Regulatory Standards

Q7. WHAT IS THE ROLE OF ROE IN ESTABLISHING A UTILITY'S RATES?

A7. The ROE compensates shareholders for the use of their capital to finance the investment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the United States Supreme Court in *Bluefield*[2] and *Hope,*[3] a utility's allowed return on common equity should be sufficient to: (1) fairly compensate capital invested in the utility; (2) enable the utility to offer a return adequate to attract new capital on reasonable terms; and (3) maintain the utility's financial integrity.

Q8. WHAT ULTIMATELY GOVERNS THE SELECTION OF A JUST AND REASONABLE ROE?

A8. The Commission has recognized that a just and reasonable ROE should be determined based on the facts specific to each proceeding.[4] Such an ROE must also meet the standards mandated by the U.S. Supreme Court.[5] As the Commission reaffirmed in Opinion No. 531,

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[2] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) ("*Bluefield*").

[3] *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

[4] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,302 at P 8 (2004) ("*Midwest ISO*"), *aff'd in relevant part sub. nom. Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005).

[5] *See, e.g.*, 106 FERC ¶ 61,302 at PP 13-14. The Commission observed that:

> [W]e are guided by the principle, enunciated by the Supreme Court, that an approved ROE should be "reasonably sufficient to assure confidence in the financial soundness of the utility [or, in this case, utilities]" and should be adequate under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.

Id. at P 13 (quoting *Bluefield*, 262 U.S. at 693).

"The Commission's ultimate task is to ensure that the resulting ROE satisfies the requirements of *Hope* and *Bluefield*."[6] This determination requires the Commission to consider all of the available evidence and to identify an ROE that is just, reasonable, and sufficient to support JCP&L's need to attract capital and earn a competitive return and, at the same time, promote the Commission's goal of encouraging investment in utility electric transmission infrastructure.

Q9. IS JCP&L FACED WITH FINANCIAL PRESSURES ASSOCIATED WITH PLANNED CAPITAL EXPENDITURES FOR ITS TRANSMISSION SYSTEM?

A9. Yes. As discussed in the testimony of Company witness Falen, JCP&L's plans call for additional transmission capital investment to address system needs, including $175 million in 2020. Support for JCP&L's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects. Investors are aware of the challenges posed by significant capital expenditure requirements, especially in light of ongoing capital market and economic uncertainties, and S&P has noted the credit implications of elevated capital expenditures for JCP&L, particularly in light of reduced cash flows attributable to the impact of the TCJA.[7]

Q10. DO CUSTOMERS BENEFIT WHEN INVESTORS HAVE CONFIDENCE THAT THE REGULATORY ENVIRONMENT IS STABLE AND CONSTRUCTIVE?

A10. Yes. Past challenges for the economy and capital markets highlight the benefits of a fair and balanced ROE, and changing course from the path of supporting utility financial strength would be extremely shortsighted. Uncertainty and volatility undermine investor

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[6] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 144 (2014) ("Opinion No. 531").

[7] S&P Global Ratings, *Research Update: Jersey Central Power & Light Co. Ratings Affirmed; Stand-Alone Credit Profile Revised to 'bbb'*, RatingsDirect (Mar. 28, 2018).

confidence, and regulatory signals are the primary driver of investors' risk assessments for utilities. Securities analysts study FERC and state commission orders and regulatory policy statements closely to gauge the financial impact of regulatory actions and to advise investors. If regulatory actions instill confidence that the regulatory environment is supportive, investors will provide the capital necessary to support needed investment. As a corollary, absent a commitment by regulators to promote a sound and stable environment for transmission investment and follow through on expectations for ROEs that are competitive with alternative investment opportunities, the flow of capital into transmission infrastructure may not continue. As a result, the need for regulatory certainty in supporting transmission infrastructure investment is as relevant today as ever.

Q11. WHAT DO YOU MEAN BY "REGULATORY CERTAINTY?"

A11. Regulatory certainty simply means that investors have confidence that prior regulatory decisions are predictive of future regulatory actions under similar facts. As the Commission has stated, it "strives to provide regulatory certainty through consistent approaches and actions."[8] The Commission's policy efforts focus on constructive and predictable rate regulation and have attracted large commitments of private capital to expand the transmission grid, reduce congestion, improve reliability, and secure access to new generation, including wind and other renewable generation. With respect to ROE in particular, the Commission has recognized the potential disincentive to investment stemming from uncertainties over the administrative process leading to a determination of a just and reasonable ROE. In Opinion No. 679-A, the Commission concluded that "our

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[8] FERC, *About FERC*, www.ferc.gov/about/about.asp (last visited Sep. 21, 2019).

hearing procedures for determining ROE can create uncertainty for investors," and noted that:

> Although our processes are designed to provide a just and reasonable return, we recognize that there can be significant uncertainty as to the ultimate return because of the uncertainties associated with administrative determinations (*e.g.*, selection of the proxy group, changes in growth rates, etc.) This can itself constitute a substantial disincentive to new investment.[9]

B. Use of Multiple Financial Models

Q12. HAS THE COMMISSION PROPOSED TO SUPPLEMENT ITS RELIANCE ON THE DCF MODEL WITH THE RESULTS OF OTHER METHODS IN EVALUATING A JUST AND REASONABLE ROE?

A12. Yes. In Opinion No. 531, the Commission adopted a two-step DCF methodology for use in evaluating a just and reasonable ROE for electric utilities.[10] Considering the potential for the two-step DCF results to be distorted and in light of prevailing conditions in capital markets, the Commission stated that it had "less confidence that the midpoint of the zone of reasonableness . . . accurately reflects the equity returns necessary" to attract capital.[11] These findings were confirmed in Opinion No. 531-B,[12] and again in Opinion No. 551.[13]

In Opinion Nos. 531 and 551, the Commission rejected values at the central tendency of the two-step DCF results—9.39% and 9.29% in the two opinions, respectively—determining that these estimates fell below a just and reasonable ROE.[14] In

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[9] *Promoting Transmission Inv. through Pricing Reform*, Order No. 679-A, 117 FERC ¶ 61,345 at P 69 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,062 (2007).

[10] Opinion No. 531 at P 8.

[11] *Id*. at P 145.

[12] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 47 (2015).

[13] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 at P 122 (2016) ("Opinion No. 551").

[14] Opinion No. 531 at P 142; Opinion No. 551 at P 256.

order to ensure that the standards in *Hope* and *Bluefield* were met, the Commission recognized that it was "necessary and reasonable" to consider the results of other ROE models and benchmarks,[15] which are widely employed in regulatory proceedings and utilized in the financial community. The Commission referenced the results of these other ROE models and benchmarks to gain insight into a point-estimate ROE from within the DCF range of returns that met the requirements of *Hope* and *Bluefield*.[16]

The benchmarks the Commission considered in Opinion Nos. 531 and 551 were: (1) a CAPM analysis, (2) an expected earnings analysis, and (3) a risk premium analysis.[17] The Commission also considered evidence of ROEs approved by state commissions to determine whether an upward adjustment to the central tendency of the DCF results was necessary.[18] Opinion No. 531 was appealed to the D.C. Circuit.

Q13. WHAT WERE THE FINDINGS OF THE DC CIRCUIT REGARDING OPINION NO. 531?

A13. On April 14, 2017, the court vacated and remanded Opinion No. 531.[19] That order—*Emera Maine*—raised two salient issues with respect to the Commission's findings in Opinion No. 531. First, it clarified that the "condition precedent" to the Commission's ability to change a rate under section 206 of the FPA hinges on a determination that an existing rate is unjust and unreasonable.[20]

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[15] Opinion No. 531 at P 145; Opinion No. 551 at P 122.
[16] *Id*.
[17] Opinion No. 531 at P 147; Opinion No. 551 at P 135.
[18] Opinion No. 531 at P 148; Opinion No. 551 at PP 135, 136.
[19] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").
[20] *Id.* at 21.

Second, the Court held that the Commission failed to adequately explain its decision to establish the ROE at the upper midpoint of the DCF zone.[21] While the Court noted that the Commission "turned to 'alternative benchmark methodologies' and 'additional record evidence' to inform its placement of the base ROE," the Court determined that the Commission did not articulate how these analyses justified the specific placement of the ROE at the upper midpoint of the two-step DCF range.[22] In remanding the case, the Court required that the Commission make "a principled and reasoned decision supported by the evidentiary record."[23]

Q14. DID *EMERA MAINE* REQUIRE THE COMMISSION TO APPLY A PARTICULAR FINANCIAL MODEL IN ARRIVING AT A JUST AND REASONABLE ROE?

A14. No. The Court did not rule on the efficacy of any financial model or otherwise constrain the Commission's prerogative to consider quantitative and qualitative evidence that it finds to be credible. Nor did the Court question the Commission's conclusion that the results of the two-step DCF method can be distorted, or otherwise indicate that the Commission was not free to fix an ROE that differed from the central tendency of the two-step DCF results. Similarly, the Court did not take issue with the supplemental ROE benchmarks relied on by the Commission in Opinion No. 531.

Rather, *Emera Maine* reaffirmed that the courts afford "great deference" to the Commission in its decision-making,[24] and noted that the Commission has "considerable

[21] *Id.* at 27-29.
[22] *Id.* at 27.
[23] *Id.* at 32 (quoting *S. Cal. Edison Co.*, 717 F.3d 177, 181 (D.C. Cir. 2013)).
[24] *Id.* at 16.

latitude" in developing a methodology to exercise its authority in arriving at a just and reasonable ROE.[25] *Emera Maine* reiterated the Court's view that ratemaking "is not a science," and the Commission "must use models to inform, not rigidly to determine, [its] judgment as to an appropriate ROE for a utility."[26]

Q15. HOW HAS THE COMMISSION PROPOSED TO ADDRESS THE FINDINGS OF *EMERA MAINE* IN EVALUATING A JUST AND REASONABLE ROE?

A15. First, as explained in the Briefing Orders, the Commission has proposed to rely on the three financial models applied in Opinion No. 531, and subsequently affirmed in Opinion No. 551, that produce a cost of equity range for use under FPA section 206 to determine a composite zone of reasonableness. These three models are the DCF model, the CAPM, and the Expected Earnings approach.[27]

Second, the Commission proposed in the Briefing Orders that, rather than relying on the results of the DCF model alone to determine a just and reasonable ROE within the composite zone of reasonableness, the Commission intends to give equal weight to four quantitative approaches (the DCF model, the CAPM, the Expected Earnings approach, and the Risk Premium method).[28] As the Commission concluded, "[i]n relying on a broader range of record evidence to estimate the [utility's] cost of equity, we ensure that our chosen ROE is based on substantial evidence and bring our methodology into closer alignment with how investors inform their investment decisions."[29]

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[25] *Id.* at 12.
[26] *Id.* at 13 (internal quotations omitted).
[27] Coakley Briefing Order at P 16; MISO Briefing Order at P 17.
[28] Coakley Briefing Order at PP 17, 59.
[29] *Id.* at P 15.

Q16. DO YOU AGREE WITH THE COMMISSION'S DECISION TO ABANDON SOLE RELIANCE ON THE DCF MODEL?

A16. Yes. As I explained in testimony submitted on behalf of the ISO New England transmission owners ("NETOs") in Docket No. EL16-64-002 and the Midcontinent ISO transmission owners ("MISO TOs") in Docket No. EL15-45-000, which were both proceedings subject to the Briefing Orders, I recommend that the Commission abandon sole reliance on the DCF model and give explicit consideration to the results of other accepted methodologies in evaluating a just and reasonable ROE.

Q17. PLEASE EXPLAIN WHY.

A17. The actual return investors require is not directly observable. Different methodologies have been developed to estimate investors' required return on capital, but all such methodologies are simply theoretical tools and generally produce a range of estimates, based on different assumptions and inputs. In light of these considerations, the courts and the Commission have recognized on numerous occasions that there is no single just and reasonable rate; rather, just and reasonable rates are defined by a zone, bounded on the high end by rates that are excessive, and on the low end by rates that are too low to provide investors with returns commensurate with those available from investments of comparable risk.

The DCF method is only one theoretical approach to gain insight into the return investors require; there are a number of other methodologies for estimating the cost of capital and the ranges (or zones) produced by the different approaches can vary widely. The Commission explained that when conditions associated with a model are outside of a normal range, there is a risk (referred to as "model risk") that the theoretical model will fail to predict or represent the real phenomenon that is being modeled.[30] As the Commission concluded, "[t]here is significant evidence indicating that combining estimates from different models is more accurate than relying on a single model."[31]

Q18. IS THE USE OF APPROACHES OTHER THAN THE DCF METHOD CONSISTENT WITH INVESTOR BEHAVIOR AND ACCEPTED REGULATORY PRACTICE?

A18. Yes. As the Commission has noted, "[t]he determination of rate of return on equity starts from the premise that there is no single approach or methodology for determining the correct rate of return."[32] Recognizing that there is no failsafe method to estimate investors' required cost of equity,[33] approaches other than the DCF model have earned widespread acceptance with investment and finance professionals, as well as regulatory agencies throughout the United States. As a result, there is no basis to conclude that investors rely on any one single method in arriving at the prices they are willing to pay for utility common stock.

A publication authored for the Society of Utility and Regulatory Financial Analysts confirmed this view, concluding that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically.

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[30] Opinion No. 531 at P 145 n.286; Opinion No. 551 at P 132 (finding that "mechanical application of the DCF methodology may produce results inconsistent with *Hope* and *Bluefield"* due to "model risk").

[31] Coakley Briefing Order at P 38; MISO Briefing Order at P 40.

[32] *Nw. Pipeline Co.*, Opinion No. 396-C, 81 FERC ¶ 61,036 at 61,188 (1997).

[33] I concur with the Commission's conclusion that "any methodology has the potential for errors or inaccuracies." Coakley Briefing Order at P 38; MISO Briefing Order at P 40.

> Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[34]

As this treatise succinctly observed, "no single model is so inherently precise that it can be relied on solely to the exclusion of other theoretically sound models."[35] Similarly, *New Regulatory Finance* concluded that:

> There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises that cannot be validated empirically. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no monopoly as to which method is used by investors. In the absence of any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities.[36]

I agree with the Commission's conclusion that "providing four different approaches to estimating the cost of equity . . . reduces the risk associated with relying on only one model; that is, the risk of misidentifying the just and reasonable ROE by relying on a flawed cost of equity estimate."[37]

Q19. IS THE CONSIDERATION OF MULTIPLE METHODS CONTINGENT ON ANY SPECIFIC CONDITIONS IN THE CAPITAL MARKETS?

A19. No. First, it is important to recognize that the merits of ROE methodologies are not at all contingent on a particular set of capital market conditions. These methods, which have considerable support in the academic, investment, and regulatory communities, obtain their

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[34] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Soc'y of Util. & Regulatory Fin. Analysts (2010) at 84.

[35] *Id.*

[36] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 429.

[37] Coakley Briefing Order at P 38; MISO Briefing Order at P 40.

relevance through widespread study and use. While there may be reasoned debate over how best to apply these methods and infer investors' cost of equity based on their results, any suggestion that particular ROE methodologies lose their relevance unless capital market conditions are found to be "anomalous" is without foundation.

While Opinion Nos. 531 and 551 cited anomalous capital market conditions as a reason for evaluating the results of the DCF model against those of other methods, the Commission also recognized that any application of the DCF model can produce unreliable results.[38] Thus, irrespective of any debate regarding the state of the capital markets, Federal Reserve policies, or the level of prevailing interest rates, the fact that the DCF method is subject to potential distortion and can produce a central tendency that is below the minimum threshold required by *Hope* and *Bluefield* supports the consideration of multiple methods to ensure that the end result meets Supreme Court standards.

As noted earlier, the practice of considering the results of multiple methods is supported by both *Emera Maine* and sound regulatory economics. This is also consistent with the advice of a recognized financial researcher and educator:

> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively.[39]

Referencing the results of multiple approaches soundly applied is also consistent with investor behavior, and the results of a variety of accepted approaches provide greater

[38] Opinion No. 531 at P 41.

[39] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 430 (citing Stewart C. Myers, *On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment*, Financial Management (Autumn, 1978) at 66-68).

insight into the expectations and requirements of investors. As a result, the four quantitative approaches included in the Briefing Orders' ROE methodology should serve as an integral part of the decision-making underlying the determination of a just and reasonable ROE at all times and under all capital market conditions.

Q20. IS THIS UNDERSTANDING CONSISTENT WITH THE COMMISSION'S GUIDANCE?

A20. Yes. As the Commission concluded in its Briefing Orders, the primary reason for averaging the results of the DCF, CAPM, Expected Earnings, and Risk Premium methods to evaluate a just and reasonable ROE "is that *investors use those models*, in addition to the DCF methodology, to inform their investment decisions."[40] Thus, the Commission concluded that "whether a change in the capital market conditions is anomalous or persistent is of less importance, because relying on multiple financial models makes it more likely that our decision will accurately reflect how investors are making their investment decisions."[41] The Commission stated that any debate over whether capital market conditions should be considered "anomalous" is now "largely irrelevant."[42]

The Commission has previously recognized that a just and reasonable ROE should be determined based on the facts specific to each proceeding, and noted, "[a]s an initial matter, we emphasize that the primary question to be considered here is not what constitutes the best overall method for determining ROE generically. . . ."[43] Rather, the

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[40] Coakley Briefing Order at P 44 (emphasis in original); MISO Briefing Order at P 46 (emphasis added).
[41] *Id.*
[42] *Id.*
[43] *Midwest ISO*, 106 FERC ¶ 61,302 at P 8.

question involves a determination of what ROE is most appropriate in each specific case.[44] As the Commission has recognized in its Briefing Orders, this evaluation should not be based on the mechanical application of a single quantitative methodology (or for that matter a mechanical application of a series of models); nor should it depend on a single statistical measure of central tendency. No single financial model predicts the required ROE with absolute precision and all financial models are based on a series of assumptions that are affected differently by market conditions. In exercising its authority, the Commission should inform its decision-making by considering the totality of the available evidence and identify an ROE for JCP&L that is just, reasonable, and sufficient to support the Commission's goal of encouraging investment in utility infrastructure.

C. Recommended ROE for JCP&L

Q21. WHAT ROE METHODOLOGY IS SUPPORTED BY YOUR EVIDENCE?

A21. Consistent with the Briefing Orders, I rely on the results of four separate financial models to evaluate a just and reasonable ROE for JCP&L. These include the constant growth form of the DCF model and the ECAPM, along with the Expected Earnings and Risk Premium approaches proposed in the Briefing Orders.

While the Commission has concluded that the median values resulting from the two-step DCF method fall far below investors' required return, diluting this downward bias by averaging these results with those produced by other methods does not remove it. In addition, the Commission has determined that "we must look to how investors analyze and

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[44] *Id.* This is consistent with *Emera Maine*, which noted that "[w]hether a rate . . . is unlawful depends on the particular circumstances of the case." *Emera Maine*, 854 F.3d at 19.

compare their investment opportunities"[45] when evaluating a just and reasonable ROE. As documented in my testimony, there is no demonstrable evidence that investors look to GDP growth rates in the far distant future in assessing their expectations for utility common stocks. Investors recognize that the electric utility industry is relatively stable and mature and the fact that analysts' EPS growth estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a primary basis for their expectations. In view of these facts, I believe the constant growth form of the DCF model provides a superior basis to evaluating a just and reasonable ROE for JCP&L.

I also include the ECAPM, which is an extension of the traditional CAPM model. The ECAPM is supported by recognized financial research and has been relied on by various parties to utility rate proceedings, including regulatory agencies and their staff. The ECAPM is designed to refine the CAPM to better reflect the observed relationship between risk and investors' required return, and my evidence supports this approach as a more representative and reliable alternative to the CAPM in evaluating a just and reasonable ROE under the general framework proposed by the Commission.

My testimony also supports a modification to the Commission's proposed test of low-end values. Specifically, in light of the inverse relationship between bond yields and equity risk premiums, reference to a static, low-end test based on a constant risk premium of 100 basis points over Baa bond yields will significantly understate the threshold for investors' minimum required return on utility stocks under current capital market

[45] Coakley Briefing Order at P 33; MISO Briefing Order at P 35.

conditions. To correct this distortion, I adjusted the low-end threshold to account for the increase to the equity risk premium that accompanies a fall in bond yields.

With respect to the median-based test of high-end results, as my testimony explains, the potential reasonableness of any cost of equity estimate is not tied to the methodology used to derive it. Accordingly, I recommend applying the Commission's proposed screen based on 150% of the highest overall median value produced by the DCF, ECAPM, and Expected Earnings methodologies, to produce a single, uniform test of high-end values.

Finally, widely-referenced forecasts available to investors continue to support the general expectation for increases in interest rates through 2023. As a result, historical average bond yields may not fully reflect investors' forward-looking expectations for long-term capital costs during the period when the rates established in this proceeding will be in effect. Accordingly, in addition to the use of historical average bond yields, I also recommend giving consideration to the results of the ECAPM and risk premium approaches using projected bond yields.[46]

Q22. DO MEDIAN VALUES NECESSARILY PROVIDE A SUPERIOR BASIS TO EVALUATE A JUST AND REASONABLE ROE IN THIS CASE?

A22. No. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. In comparing the risks and prospects of JCP&L with other opportunities, there is no reason to believe that investors would distinguish between utilities where the ROE is established on a stand-alone basis and those

[46] As noted in the Coakley Briefing Order, the Commission relied on a range of cost of equity estimates produced by the Risk Premium method of 10.7% to 10.8%, which correspond to the results based on historical and projected bond yields, respectively. Coakley Briefing Order at P 59 n.115.

that are subject to a single, RTO-wide ROE determination (e.g., NETOs and the MISO TOs). Discriminating between single utilities and the NETOs or MISO TOs when evaluating a point estimate within the DCF range would violate the *Hope* and *Bluefield* standards governing the determination of a just and reasonable ROE in this case.

In fact, capital markets are highly sophisticated and JCP&L must compete for capital with utilities across the nation, irrespective of any mechanical policies used by the Commission to establish a point estimate ROE from within a proxy group range. As a result, differentiating between a proceeding involving a single transmission utility and a joint filing of multiple RTO members ignores the requirements of investors, which are based on comparable-risk opportunities available in the capital markets. This is consistent with the findings of Opinion No. 531. In approving the use of a national proxy group over a regional proxy group, the Commission observed that the determination "is a question of capital attraction and comparability of risk." As the Commission concluded:

> We agree that "the NETOs must compete for capital with other utilities (and companies in other sectors) throughout the nation," and that investors are not limited to investments in geographically adjacent states but instead participate in national or international capital markets. If the NETOs' ROE is significantly less than the returns of utilities in other parts of the nation, capital will more readily flow to areas other than New England and the NETOs may not be able to attract sufficient capital consistent with the *Hope* and *Bluefield* standards.[47]

Similarly, there is no basis to arbitrarily categorize the Commission's ROE policies based on an artificial distinction between utilities that are subject to a unified, RTO-wide ROE and single utilities, such as JCP&L. Rather, in order to meet the *Hope* and *Bluefield* standards, the Commission's evaluation must be premised on the risk perceptions and

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[47] Opinion No. 531 at P 96 (footnotes omitted).

requirements of actual investors in the capital markets, who do not determine their required returns for utilities based solely on whether the company's FERC-jurisdictional ROE happens to be fixed as the result of a single-company proceeding, or on an RTO-wide basis. As a result, a mechanical policy of referencing the median is not supported.

Q23. IS CONSIDERATION OF THE MIDPOINT RESULTS CONSISTENT WITH THE PRINCIPLES UNDERLYING A JUST AND REASONABLE ROE FOR JCP&L?

A23. Yes. The Commission has recognized that a just and reasonable ROE should be determined based on the facts specific to each proceeding, as the Commission explained in *Midwest ISO*:

> As an initial matter, we emphasize that the primary question to be considered here is not what constitutes the best overall method for determining ROE generically (*i.e.*, the midpoint versus the median or mean); it is whether use of the midpoint is most appropriate in this case.[48]

The paramount consideration that must be reflected in the choice of a just and reasonable ROE is the need to ensure that the end result meets the standards mandated by the Supreme Court in *Hope* and *Bluefield* to ensure that a utility can attract capital. This determination is not a quest to ordain a single statistical measure of central tendency. Rather, the Commission must consider the available evidence to make an informed evaluation of an ROE that is just, reasonable, and sufficient to support investment.

Q24. WHAT ROE IS IMPLIED FOR JCP&L UNDER YOUR APPLICATION OF THE FOUR-MODEL METHODOLOGY?

A24. The results of my application of the four-model methodology are shown on Exhibit No. JCP-202 and summarized in the table below:

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[48] *Midwest ISO*, 106 FERC ¶ 61,302 at P 8.

TABLE JCP-1
ROE UNDER FOUR MODEL METHODOLOGY

Method	Range	Median	Midpoint
Constant Growth DCF	6.87% -- 14.93%	9.01%	10.90%
ECAPM	8.51% -- 11.60%	10.20%	10.05%
Expected Earnings	8.20% -- 14.60%	10.75%	11.40%
Risk Premium	-- --	10.16%	10.16%
Average	**7.86% -- 13.71%**	**10.03%**	**10.63%**

As shown above, application of the four model methodology results in a composite ROE zone of reasonableness of 7.86% to 13.71%, with median and midpoint values averaging 10.03% and 10.63%, respectively.

Q25. WHAT DO YOU CONCLUDE WITH RESPECT TO A JUST AND REASONABLE ROE FOR JCP&L?

A25. Based on the results of my analyses, I determined that a base ROE of 10.3% is just and reasonable for the Company. As noted above, in making an informed evaluation of an ROE that is just, reasonable, and sufficient to support investment, the Commission should consider both median and midpoint results. A base ROE of 10.3% is bracketed by the 10.03% and 10.63% averages of the median and midpoint values produced by the four financial models considered in my analysis. As supported in my testimony, and in light of investor behavior and financial research, my analysis represents a reasonable estimation of the ROE required to attract capital investment in JCP&L and opportunities of similar risk.

Q26. IS A BASE 10.3% ROE CONSISTENT WITH ESTABLISHED COMMISSION POLICY TO SUPPORT INVESTMENT IN ELECTRIC TRANSMISSION INFRASTRUCTURE?

A26. Yes. The Commission's regulatory actions have been successful in supporting much needed investment in wholesale transmission infrastructure. Unresponsive, mechanical decision-making that leads to inadequate returns would undermine the Commission's goal and the legislative mandate to promote capital investment in new transmission projects.

This potential adverse outcome was highlighted by the investment community with respect to the transmission segment of the power industry:

> The degree to which a utility revises its transmission capital plan will depend on expected returns…. Material reductions in the base ROE could lower the quality of and divert capital away from the transmission business, given its generally riskier profile than that for state-regulated utility businesses, such as distribution and generation. Moreover, investors could deploy capital to infrastructure projects with higher allowed returns, such as FERC-regulated natural gas pipelines, or to other industries generally.[49]

The investment community has also recognized that setting the ROE for FERC-jurisdictional transmission infrastructure below the level allowed by state commissions would undermine the ability of interstate operations to compete for capital. The global financial firm UBS observed that:

> We believe companies will redeploy capital elsewhere if transmission returns are materially reduced. In our view, the cost of capital could actually increase, because as returns are set lower, valuation multiples will also be reset much lower than current levels. Additionally, the second order effects on other state and Federal government policy objectives, i.e. renewables development, could be significant, in our view.[50]

Similarly, Wolfe Research stated that unsupportive regulatory policies represent "a real risk for transmission owners," and concluded, "[w]e fear the uncertainty over transmission ROEs could fester."[51]

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[49] Wolfe Research, Utils. & Power, *FERConomics: Risk to transmission base ROEs in focus* (June 11, 2013) at 11.

[50] *See* Opinion No. 531 at P 150 n.301 (citing *Coakley v. Bangor Hydro-Elec. Co.*, Docket No. EL11-66-001, Exh. NET-400, Testimony of Ellen Lapson on Behalf of the New England Transmission Owners at 18 (Nov. 20, 2012) (quoting UBS Inv. Research, U.S. Elec. Utils. & IPPS, *Transmission: CTRL+Z?,* (May 3, 2012) at 1)).

[51] Wolfe Research, Utils. & Power, *Don't you FERCed about ROE, Don't Don't Don't!* (Apr. 6, 2015).

The need for regulatory certainty in supporting transmission infrastructure investment is as relevant today as ever, particularly in light of JCP&L's plans for significant transmission capital expenditures. A base ROE of 10.3% for JCP&L is appropriate in light of the continued need to attract capital to transmission infrastructure and the imperative of meeting the *Hope* and *Bluefield* standards.

Q27. WHAT CONCLUSIONS DO YOU REACH REGARDING THE MEDIAN OF THE DCF MODEL?

A27. As indicated by the results summarized on Exhibit No. JCP-202, application of the ECAPM, Expected Earnings, and Risk Premium methodologies, as well as other indicators of investors' required returns that I discuss further below, demonstrates that the 9.01% median value resulting from the DCF method alone is far below investors' required return. Consistent with Opinion Nos. 531 and 551, these methodologies show that the median of the DCF estimates would not produce a just and reasonable end result.

Q28. IS JCP&L ENTITLED TO ANY RTO INCENTIVE ADDERS?

A28. Yes. Under Commission precedent and in accordance with Order No. 697 and its progeny,[52] JCP&L is entitled to a 50 basis point adder for its voluntary participation in the PJM RTO. The RTO incentive adder was implemented in "recognition of the benefits that flow from membership in such organizations and the fact [that] continuing membership is

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[52] *See, e.g., Pepco Holdings, Inc.*, 121 FERC ¶ 61,169 at P 15-16 (2007); *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 at P 326 (2006), *order on reh'g*, Order No. 679-A at P 86; *see also Ass'n. of Businesses Advocating Tariff Equity Coal. of MISO Transmission Customers v. Midcontinent Indep. Sys. Operator Inc.*, 149 FERC ¶ 61,049 at P 200 (2014) ("The Commission stated in Order No. 679 that entities that have already joined, and that remain members of, an RTO, ISO, or other Commission approved transmission organization, are eligible to receive this incentive.").

generally voluntary."[53] Thus, JCP&L's voluntary decision to join and maintain its membership in PJM results in its entitlement to the standard 50 basis point incentive adder.

III. DEVELOPMENT AND SELECTION OF A PROXY GROUP

Q29. CAN QUANTITATIVE METHODS BE APPLIED DIRECTLY TO JCP&L TO ESTIMATE THE COST OF EQUITY?

A29. No. Application of the DCF model, as well as the ECAPM and Expected Earnings analyses, requires observable capital market and financial data, such as stock prices and beta values.

Q30. WITHOUT STOCK PRICES OR OTHER MARKET DATA FOR JCP&L, HOW CAN FINANCIAL MODELS BE APPLIED TO ESTIMATE THE COST OF EQUITY?

A30. As an alternative, the cost of equity for an untraded firm is often estimated by applying financial models using data for publicly traded companies engaged in the same business activity. Even for a company with publicly traded stock, the cost of equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation or measurement error. Thus, the accepted approach to increase confidence in the results is to apply these methods to a proxy group of publicly traded companies that investors regard as risk comparable. The results of the analysis on the sample of companies are relied upon to establish a range of reasonableness for the cost of equity for the specific company at issue.

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[53] *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 at P 331 (2006), *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

Q31. WHAT SPECIFIC CRITERIA DO YOU INITIALLY EXAMINE TO IDENTIFY A PROXY GROUP?

A31. Consistent with the approach adopted by the Commission in Opinion Nos. 531 and 551, I begin with the following criteria to identify a proxy group of utilities:

1. Companies that are included in the Electric Utility Industry groups compiled by Value Line.
2. Electric utilities that paid common dividends over the last six months and have not announced a dividend cut since that time.
3. Electric utilities with no ongoing involvement in a major merger or acquisition that would distort quantitative results.

In addition, the Commission determined in Opinion No. 531 that credit ratings from both major agencies—S&P and Moody's—should be considered independently as screening criteria when evaluating comparable risk.[54] In evaluating credit ratings to identify a proxy group of utilities with comparable risks, the Commission has adopted a comparable risk band, interpreted as one notch higher or lower than the corporate credit ratings of the utility at issue and within the investment grade ratings scale.[55]

Q32. WHAT DOES THIS IMPLY WITH RESPECT TO THE DETERMINATION OF A PROXY GROUP COMPARABLE TO JCP&L?

A32. JCP&L has been assigned a corporate credit rating of BBB by S&P, while Moody's currently rates the Company at Baa1. Applying the one notch higher or lower band under the Commission's guidelines results in a screening criterion based on S&P credit ratings of BBB- to BBB+. Meanwhile, the comparable risk band based on Moody's long-term issuer ratings is Baa2 to A3.

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[54] Opinion No. 531 at P 107.

[55] *See, e.g.*, *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 53 (2010) ("*SoCal Edison*"); *Tallgrass Transmission LLC*, 125 FERC ¶ 61,248 at P 77 (2008).

Q33. IS THERE ANY OTHER PUBLICLY TRADED UTILITY THAT IS RELEVANT IN ESTABLISHING A PROXY GROUP?

A33. Yes. Investors would regard Algonquin as a comparable investment alternative that is relevant to an evaluation of a just and reasonable ROE for JCP&L. Although it has not yet been included in Value Line's electric utility industry groups, investors also regard Algonquin as having operations comparable to those of other electric utilities in the proxy group. Algonquin is a North American diversified generation, transmission, and distribution utility with approximately $10 billion in total assets. Algonquin provides regulated utility services to over 750,000 customers in Arizona, Arkansas, California, Georgia, Illinois, Iowa, Kansas, Massachusetts, Missouri, New Hampshire, Oklahoma, and Texas. Algonquin completed its acquisition of Empire District Electric on January 1, 2017, which more than doubled its size.[56] A majority of Algonquin's revenues, earnings, and assets are related to its regulated U.S. utility operations.[57] In addition, Algonquin reports interim and annual consolidated financial statements in U.S. dollars, its dividend is denominated in U.S. dollars, and its common shares are listed on the New York Stock Exchange.

[56] Empire District Electric was included in Value Line's electric utility industry group prior to its merger with Algonquin.

[57] For example, Algonquin reported that during 2018 regulated utility operations accounted for 85% of total revenues, 85% of pre-tax earnings (ex. corporate losses), and 64% of total assets. Approximately 96% of Algonquin's consolidated revenue and 93% of assets are attributable to operations in the U.S. https://www.sec.gov/cgi-bin/viewer?action=view&cik=1174169&accession_number=0001140361-19-004116&xbrl_type=v#.

While Algonquin is not rated by Moody's, it has been assigned a credit rating of BBB by S&P, which falls within the comparable risk band for JCP&L.[58] The historical stock price and dividend data necessary to apply the DCF approach are available, and analysts' consensus EPS growth estimates are also published for Algonquin. Moreover, Algonquin is not engaged in any ongoing merger transactions that might otherwise distort inputs to the DCF model.[59]

As shown on Exhibit No. JCP-203, applying the criteria outlined above results in a proxy group of twenty utilities.

IV. APPLICATION OF FINANCIAL MODELS

Q34. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A34. This section presents my application of the four-model methodology. Specifically, as noted above, I apply the constant growth form of the DCF model, ECAPM, Expected Earnings, and Risk Premium methods.

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[58] The Commission does not require that a company have both S&P and Moody's credit ratings for inclusion in a proxy group. *See* Opinion No. 531 at P 107.

[59] While Algonquin announced a planned acquisition of the parent company of Bermuda Electric Light Company on June 3, 2019, the aggregate purchase price of approximately $365 million represents less than 4% of Algonquin's total assets. As the Commission determined, "[e]xcluding . . . companies from the proxy group on the basis of any small purchase or sale would unnecessarily shrink the group of representative companies, thereby making the proxy group, and the resulting DCF analysis, a less reliable tool for ensuring that the allowed ROE satisfies the requirements of Hope and Bluefield." Opinion No. 551 at P 41. In addition, there is no evidence that any of the model inputs have been distorted by this announced acquisition.

A. DCF Model

Q35. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A35. DCF models assume that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price appreciation) that will be received while holding the stock, discounted at investors' required rate of return. Thus, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock.

Q36. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF EQUITY?

A36. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[60]

$$P_0 = \frac{D_1}{k_e - g}$$

where:
P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
k_e = Cost of equity; and
g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

[60] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (i.e., no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: (1) dividend yield (D_1/P_0) and (2) growth (*g*). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through stock price appreciation.

Q37. WHAT IS THE DISTINCTION BETWEEN THE COMMISSION'S TWO-STEP DCF METHOD FOR ELECTRIC UTILITIES AND THE CONSTANT GROWTH MODEL OUTLINED ABOVE?

A37. The Commission's two-step DCF method for electric utilities assumes that investors differentiate between near-term growth forecasts, such as the EPS growth rates published by securities analysts, and some notion of longer-term growth into the far distant future. Based on this assumption of disparate growth expectations, which I disagree with as detailed below, the two-step DCF method employs two separate growth rates for each company, which are then weighted to arrive at a single value for the "*g*" component.

Q38. HAS THE COMMISSION RECOGNIZED THAT THE RESULTS OF THE TWO-STEP DCF APPROACH ARE NOT NECESSARILY INDICATIVE OF INVESTORS' COST OF EQUITY?

A38. Yes. The Commission confirmed the potential unreliability of its two-step DCF model in Opinion No. 531 itself, noting that, under conditions analogous to those present in capital markets today, an ROE based on the midpoint of the DCF range would violate the *Hope* and *Bluefield* standards.[61] More recently, the Commission affirmed that relying on its two-

[61] Opinion No. 531 at P 142.

step DCF methodology alone "will not produce a just and reasonable ROE," and that this method "may no longer singularly reflect how investors make their decisions."[62]

Q39. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH REFERENCING GDP GROWTH IN APPLYING THE DCF MODEL?

A39. Yes, there are several:

1. Practical application of the DCF model does not require a long-term growth estimate over a horizon of 30 years and beyond—it requires a growth estimate that matches investors' expectations.
2. Evidence supports the conclusion that investors do not reference long-term GDP growth in evaluating expectations for individual common stocks, including those in the utility industry.
3. The theoretical proposition that growth rates for all companies converge to overall growth in the economy over the very long term does not guide investors' views, and growth rates for utilities can and do routinely exceed GDP growth.
4. There is no evidence that investors' growth expectations for regulated electric utilities have begun to converge to that of the economy.

In short, there is no demonstrable evidence that investors look to GDP growth rates in the distant future in assessing their expectations for utility common stocks. And while the theoretical assumptions underlying this method contemplate an infinite stream of cash flows, this is simply at odds with the practical circumstances in which real-world investors operate. The Commission's findings in Opinion Nos. 531 and 551 present very clear analysis that the two-step DCF model results in cost of equity estimates that fall far below investors' expectations and violate regulatory standards of fairness.

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[62] Coakley Briefing Order at PP 32, 40; MISO Briefing Order at PP 34, 42.

Q40. THE DCF MODEL IS BASED ON THE ASSUMPTION OF AN INFINITE STREAM OF CASH FLOWS. WHY WOULDN'T A TRANSITION TO GDP GROWTH MAKE SENSE?

A40. This view confuses the theory underlying the DCF model with the practicalities of its application in the real world. While the notion of long-term growth should presumably relate to a specific or to a particular industry, there are no long-term growth projections available for the companies in the proxy group or for the electric utility industry as a whole. By applying the DCF model in a way that is inconsistent with the information that is available to investors and how they use it, the use of GDP growth gives the theoretical assumptions of a financial model primacy over investor behavior. The only relevant growth rate is the growth rate used by investors. Investors do not have clarity to see that far into the future, and there is little to no evidence to suggest that investors share the view that growth in GDP must be considered a limit on earnings growth over the long-term.

Q41. ARE THERE CIRCUMSTANCES THAT MIGHT SUPPORT THE USE OF A TWO-STAGE, OR MULTI-STAGE DCF APPROACH?

A41. Yes. Reference to multiple growth rates may be reflective of investors' expectations for firms at the early stage of the corporate life cycle. Pioneering development firms may experience explosive earnings growth in initial years, which could reasonably be expected to moderate as the firm matures. As the Commission has noted, "[s]hort-term growth may be atypically high or low depending on the industry cycle."[63] Alternatively, a profound and definable shift in an industry's economics could also warrant consideration of multiple growth rates. For example, in deciding to adopt a two-step model for gas pipelines, the

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[63] *Nw. Pipeline Co.*, Opinion No. 396-C, 81 FERC ¶ 61,036 at 61,189 (1997).

Commission was concerned that IBES growth rates were "too influenced by the current position of the industry,"[64] noting:

> Northwest's expert witness testified that the short-term IBES figures were at historic high levels because the pipeline industry was recovering from the deterioration in earnings resulting from the collapse in oil prices and dramatic changes in regulatory framework.[65]

Similarly, in the 1990s when investors thought the electric utility industry was transitioning to non-regulated markets, two-stage models arguably fit investors' expectations. The first stage was based on expectations of growth rates under regulation and the second stage would be more akin to non-utility growth rates. A number of experts presented two-stage models based on investors' expectations of a transition and a number of regulatory agencies found these models to be reasonable.

But expectations of widespread deregulation are a relic from the past and there is no evidence that the growth transition implied by a two-step model fits the expectations that investors currently build into electric utility stock prices. Investors recognize that while the electric utility industry is facing the possibility of disruption related to accelerating technological shifts, it is relatively stable in comparison to many other sectors, and there is no evidence that they anticipate a series of discrete, life cycle stages for the companies in the proxy group. As a result, there is no discernable transition that would support use of two-step or multi-stage DCF approaches.

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[64] *Id.* at 61,197.
[65] *Id.*

Q42. ARE LONG-TERM GDP GROWTH RATES COMMONLY REFERENCED AS A DIRECT GUIDE TO FUTURE EXPECTATIONS FOR SPECIFIC FIRMS, SUCH AS ELECTRIC UTILITIES?

A42. No. Certainly investors consider broad secular trends in economic activity as one foundation for their expectations for a particular industry or firm. But the idea that investment advisory services view GDP growth as a direct guide to long-term expectations for a particular firm—much less every firm in an entire industry—is not borne out by evidence.

In contrast to this notion, the financial media typically refers to three-to-five year EPS growth forecasts for individual companies and only rarely, if ever, mentions long-term GDP forecasts in commenting on investment prospects. Long-term GDP growth rates are simply not discussed within the context of establishing investors' expectations for individual companies. For example, Value Line reports are routinely cited as a reliable source, but Value Line does not even mention trends in GDP in its evaluation of the firms in the electric utility industry. Value Line's singleness of purpose is to inform investors of the pertinent factors that impact future expectations specific to each of the common stocks it covers. If a fifty-year trajectory of GDP growth had direct relevance in investors' evaluation of electric utility common stocks, it would be logical to assume that Value Line or other securities analysts would give at least passing mention to this fact. But they do not.

Q43. HOW MUCH CONFIDENCE WOULD INVESTORS BE LIKELY TO PLACE ON LONG-TERM GDP PROJECTIONS?

A43. Very little. There are understood complexities and inherent inaccuracies involved in forecasting, and such uncertainties are significantly compounded for a long-term time horizon. Consider the example of IHS Global Insight, which is perhaps the world's foremost econometric forecasting service. IHS Global Insight publishes GDP projections for the U.S. economy for the next thirty years, but for other important economic variables (*e.g.*, bond yields) their forecasts routinely hold projected values constant after a five-year horizon.

Q44. IS THERE EVIDENCE THAT LONG-TERM GDP GROWTH RATES UNDERSTATE INVESTORS' EXPECTATIONS FOR ELECTRIC UTILITIES?

A44. Yes. Actual historical growth rates for individual companies refute the notion that long-term growth for electric utilities is constrained by GDP. For example, Value Line reports that CMS Energy Corporation, NorthWestern Corporation, and DTE Energy Company—all mature, long-lived electric utilities—achieved earnings growth over the last 10 years of 10.0%, 8.5%, and 8.0%, respectively.[66] GDP growth over this period, however, was far lower. These values thus indicate that utilities can and do achieve growth over extended periods well in excess of the GDP growth rate, which highlights a serious flaw in the Commission's two-step DCF model. Again, this indicates that investors' views are not generally aligned with the long-term GDP growth rate incorporated into the Commission's two-step DCF.

Q45. DO EXPECTATIONS FOR THE UTILITY INDUSTRY SUPPORT A LONG-TERM TREND TOWARDS GDP GROWTH?

A45. No. Industry fundamentals do not suggest that investors are anticipating growth rates for electric utilities to uniformly trend downward to the growth rate in the overall economy. At least in part, growth in the electric utility industry is created by additional infrastructure investment. Contrary to the assumption that growth trends will somehow mirror GDP,

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[66] The Value Line Investment Survey (Jun. 14, 2018; Jul. 26, 2019).

investors recognize that the electric utility industry has entered a cycle of significant capital spending on utility infrastructure.

Q46. WHAT UNDERLYING FUNDAMENTALS SUPPORT INVESTORS' CONCLUSION THAT ELECTRIC UTILITIES ARE EMBARKING ON A PERIOD OF GROWTH THAT WILL OUTPACE THE ECONOMY AS A WHOLE?

A46. As the Commission's Order No. 1000 recognized,[67] the need for additional infrastructure investment in the utility industry is being driven in large part by changes in generation mix and mandated transitions to renewable resources at the state level. A 2016 report on utility capital spending by Deloitte concluded, "[o]verall, company projections indicate that capital expenditures will likely remain substantial, which is not surprising, since key drivers behind the spending continue."[68] Consistent with these observations, the President of EEI observed that capital expenditures in the electric utility industry reached a record high of $119.5 billion in 2018.[69]

Similarly, the investment community also understands that utilities are facing the prospect of a long-term commitment to infrastructure investment. For example, S&P has observed that:

> S&P Global Market Intelligence foresees continued high levels of capital spending by the industry, both on regulated and unregulated investment. Regulated capital spending includes spending on infrastructure replacement, new transmission and distribution facilities and lines, and

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[67] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 at P 45 (2011), *order on reh'g and clarification*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd*, *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (per curiam).

[68] Deloitte, *From growth to modernization, the changing capital focus of the US utility sector* (2016).

[69] Thomas R. Kuhn, *President's Letter*, EEI 2018 Financial Review.

> regulated power plants, including new nuclear units currently under construction.[70]

More recently, RRA concluded that:

> Projected 2019 capital expenditures for the 48 gas and electric utilities in the RRA universe are up to $131.1 billion, over 9% higher than the prior forecast of $119 billion in the fall 2018. . . . The nation's electric and gas utilities are investing in infrastructure to upgrade aging transmission and distribution systems, build new natural gas, solar, and wind generation, and implement new technologies, including smart meter deployment, smart grid systems, cybersecurity measures and battery storage. [71]

RRA further concluded that "[w]e expect considerable levels of spending to serve as the basis for solid profit expansion for the foreseeable future."[72]

Q47. HAS THE COMMISSION RECOGNIZED THAT THE UNDERLYING FUNDAMENTALS OF THE ELECTRIC UTILITY INDUSTRY ARE INCONSISTENT WITH THOSE THAT ORIGINALLY MOTIVATED THEIR USE OF THE TWO-STEP DCF MODEL?

A47. Yes. While adoption of the two-step approach in Opinion No. 531 aligned the DCF method for electric utilities with that used for natural gas and oil pipelines, investors' growth expectations for pipelines and electric utilities are not in synchronicity. Nor do the analysts' growth rates for the proxy firms in evidence in this proceeding resemble those that originally motivated the adoption of the two-step DCF model, which stemmed from the Commission's concerns over IBES growth rates that were perceived to be atypically high. This was noted by the Presiding Judge in *Northwest Pipeline*:

> For many years growth in the [pipeline] industry was sluggish and the IBES predictions were accordingly modest, but after the issuance of Order No. 636, IBES forecasts reflected higher expectations of growth for the proxy

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[70] Standard & Poor's Corporation, *Industry Surveys, Electric Utilities* (February 2016).

[71] S&P Global Market Intelligence, *RRA Financial Focus – Utility Capital Expenditures Update* (May 1, 2019).

[72] *Id*.

> group companies in the years ahead. Suddenly confronted with unusually high DCF rate of return recommendations based upon these higher projections for revenue growth, the Commission balked, and sought to offset short run optimism with more conservative estimates for the long run.[73]

The magnitude of the disparity between the near-term growth rates for pipelines and growth in GDP that prompted the use of the two-step model bears no similarity to the evidence in this proceeding. For example, in *Transcontinental Gas*, IBES growth rates for the proxy group ranged from 8.0% to 15.0% and averaged 11.3%.[74] In Opinion No. 531, however, the Commission concluded that "the IBES growth projections of electric utilities continue to reflect a different pattern from those of natural gas and oil pipelines."[75] This "different pattern" has significant implications with respect to the validity of the two-step DCF model as applied to electric utilities. The Commission's original adoption of the two-step DCF model envisioned a "short-term transition stage," after which the relatively high near-term IBES growth rates for pipelines would be expected to moderate and reach "a state of maturity."[76] However, the facts in this case are different from those that motivated the Commission's shift from the constant growth to the two-step DCF model for gas

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[73] *Nw. Pipeline Corp.*, 77 FERC ¶ 63,007 at 65,014-15 (1996) ("*Northwest Pipeline*"), *rev'd*, Opinion No. 396-B, 79 FERC ¶ 61,309, *reh'g denied*, Opinion No. 396-C, 81 FERC ¶ 61,036 (1997).

[74] *Transcon. Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084 at Appendix A ("*Transcontinental Gas*"), *order on reh'g*, Opinion No. 414-B, 85 FERC ¶ 61,323 (1998); *see also Williston Basin Interstate Pipeline Co.*, 91 FERC ¶ 63,005 at Attachment A (2000) (reporting IBES growth rates for the six-company proxy group ranging from 8.0% to 15.0%).

[75] Opinion No. 531 at P 38.

[76] *Ozark Gas Transmission Sys.*, 68 FERC ¶ 61,032 at 61,105 (1994), *order on reh'g*, 71 FERC ¶ 61,138 (1995).

pipelines.[77] There is no indication that analysts' EPS growth rates for the electric utilities in the proxy group are characterized by the "short run optimism" that led the Commission to adopt the two-step DCF model, particularly in light of long-term expectations of continued high levels of capital investment.

Q48. ARE THERE ANY ACADEMIC STUDIES THAT ADDRESS THE USE OF A GENERIC LONG-TERM GROWTH RATE, SUCH AS THE GDP GROWTH UNDER THE TWO-STEP APPROACH?

A48. Yes. Professor Myron J. Gordon, who pioneered the application of the constant growth DCF approach, stated that reference to a generic long-term growth rate was unsupported.[78] More specifically, Dr. Gordon concluded that any assumption of a single time horizon for a transition to a generic long-term growth rate was highly questionable and failed to reduce error in DCF estimates. Instead, Dr. Gordon specifically recognized that, "it is the growth that investors expect that should be used" in applying the DCF model, and he concluded: "A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[79]

Similarly, a subsequent paper co-authored by Dr. Gordon concluded that "[a]nalysts do not predict earnings beyond five years, which suggests that any consensus of opinion among investors probably deteriorates quickly after five years."[80] Dr. Gordon

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[77] A review of the IBES growth rates on Exhibit No. JCP-204 indicates that all but two of these estimates falls below the 8.0% low-end value considered in *Transcontinental Gas*, for example.

[78] Myron J. Gordon, *The Cost of Capital to a Public Utility*, MSU Pub. Util. Studies (1974) at 100-01.

[79] *Id.* at 89.

[80] Joseph R. Gordon and Myron T. Gordon, *The Finite Horizon Expected Return Model*, Financial Analysts Journal (May-Jun. 1997), pp. 52-61.

concluded that "the consensus among investors is that the future has a finite horizon of approximately seven years."[81] Meanwhile, a study reported in the *Journal of Investing* determined that there is no correlation between stock market returns or earnings growth and GDP, suggesting that investors' expectations built into observable share prices are driven by valuation measures, and not expected economic growth.[82] In other words, reference to long-term forecasts of GDP growth in applying the DCF model is inconsistent with investor behavior.

Q49. DO OTHER FORMULATIONS OF THE DCF MODEL OFFER A RELEVANT BENCHMARK FOR PURPOSES OF EVALUATING A JUST AND REASONABLE ROE FOR JCP&L?

A49. Yes. As this discussion makes clear, just as no single quantitative approach is definitive, applying the DCF model is not a "one-size-fits-all" proposition. The Commission has determined that "we must look to how investors analyze and compare their investment opportunities."[83] There is no evidence to support a finding that investors' current expectations for electric utilities follow the pattern assumed by the two-step DCF model. As documented above, the long-term cycle of capital investment implies higher—not lower—long-term growth, and suggests that GDP growth estimates understate investors' expectations for electric utilities. In this light, I believe the constant growth DCF model provides a better benchmark that is more consistent with the way in which investors assess their expectations and evaluate common stocks.

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[81] *Id.*

[82] Joachim Klement, "What's Growth Got to Do with It? Equity Returns and Economic Growth," *Journal of Investing,* Vol. 24, No. 2 (Summer 2015): 74:78.

[83] Coakley Briefing Order at P 33; MISO Briefing Order at P 35.

Unlike the two-step DCF approach, which is based on an assumption of a discrete change in expected growth rates, the constant growth form of the DCF model employs a single growth parameter, which is generally based on EPS growth projections of securities analysts, such as the IBES growth rates that are commonly relied upon by the Commission. This single-stage version of the DCF model is the form of the model most widely referenced by financial practitioners and regulatory agencies. As a result, it is highly relevant in any evaluation of investors' required cost of equity for electric utilities.

Q50. HOW DO YOU DETERMINE THE DIVIDEND YIELD FOR THE UTILITIES IN YOUR PROXY GROUP?

A50. An average dividend yield is developed for each electric utility in the proxy group during the six months from April through September 2019. This calculation is made by dividing the indicated dividend in each month by the corresponding average of the monthly low and high stock prices. Consistent with the dividend yield calculations adopted by the Commission in Opinion No. 551, I use the dividend declared in each month of the analysis period to determine the indicated annual dividend.[84]

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[84] This differs from the calculations underlying the DCF results presented in the Appendix to Opinion No. 531, which were based on the most recent declared dividend at the end of the six-month analysis period. While use of the most recent declared dividend, as the Commission adopted in Opinion No. 531, is more congruent with the assumptions of the DCF approach, I utilized the historical dividends over the study period in deference to the Commission's findings in Opinion No. 551.

Q51. WHAT IS THE SOURCE OF THE ANALYSTS' CONSENSUS EPS GROWTH RATES USED IN YOUR APPLICATION OF THE DCF METHOD?

A51. I obtain IBES earnings growth rates for the utilities in the proxy group from *Yahoo! Finance*, which has long been accepted and relied on by the Commission in applying the DCF approach.[85]

Q52. ARE THERE ALTERNATIVE SOURCES OF CONSENSUS GROWTH RATES THAT ARE COMPARABLE TO IBES?

A52. Yes. While the Commission has customarily relied on IBES EPS growth rates from *Yahoo! Finance*, there are other well recognized financial data platforms available to investors that publish comparable data.[86] While such growth rate estimates are considered by investors and represent a credible alternative to IBES, the Commission has yet to incorporate EPS growth rates from sources other than IBES in applying the two-step DCF model, as it has for the CAPM.[87] As a result, while I believe this data can represent a sound basis on which to apply the DCF model, I elected not to rely on alternative consensus growth estimates in applying the DCF methodology at this time.

Q53. WHERE DO YOU PRESENT THE RESULTS OF YOUR DCF ANALYSIS?

A53. After combining the dividend yields and the respective analysts' growth projections for each utility, the resulting DCF cost of equity estimates are shown on Exhibit No. JCP-204.

Q54. HOW DO YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A54. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for the additional risk they assume. As

[85] Opinion No. 531 at P 89.

[86] Specifically, Bloomberg L.P., FactSet Research Systems Inc., S&P Capital IQ, and Zack's Investment Research also report consensus EPS growth rates.

[87] Opinion No. 551 at P 169.

a result, the rate of return that investors require from a utility's common stock, the most junior and risky of a company's securities, must be considerably higher than the yield offered by senior, long-term debt. In Opinion No. 531, FERC concluded that, "[t]he purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[88] The Commission has used a risk premium of 100 basis points above the six-month average Baa-rated public utility bond yield as an approximation of this threshold, but has also recognized that this is a "flexible test."[89] The Commission noted in the Briefing Orders that it "will continue to use this test for purposes of the CAPM and Expected Earnings analyses as well as the DCF analysis."[90]

Q55. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING COST OF EQUITY ESTIMATES AT THE LOW END OF THE RANGE?

A55. While I agree with the Commission that the yields on Baa-rated public utility bonds serve as a useful indicator in evaluating the reasonableness of cost of equity estimates at the low end of the range, I disagree with the Briefing Orders' proposal to use a fixed risk premium of 100 basis points to establish the low-end threshold. The Commission has historically relied on a 100 basis point spread over public utility bond yields as a starting place in evaluating low-end values, but reference to a static test ignores the implications of the

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[88] Opinion No. 531 at P 122.
[89] Opinion No. 531 at P 122. *See also, e.g.*, *SoCal Edison*, 131 FERC ¶ 61,020 at PP 54-56.
[90] Coakley Briefing Order at P 51; MISO Briefing Order at P 52.

inverse relationship between equity risk premiums and bond yields, which the Commission has repeatedly acknowledged.

Specifically, the risk premium that investors demand in order to bear the higher risks of common stock is not constant. As I demonstrate later in my testimony, and as the Commission has recognized,[91] equity risk premiums expand when interest rates fall, and vice versa. The Commission first referenced a 100 basis point risk premium over Moody's bond yield averages as a threshold to eliminate DCF results in *SoCal Edison*, citing prior decisions in *Atlantic Path 15,*[92] *Startrans,*[93] and *Pioneer*[94] in support of this policy.[95] Because bond yields declined significantly between the time of those findings and the study period in this case, the inverse relationship implies a significant increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. As a result, using a fixed premium of 100 basis points over public utility bond yields will vastly understate the threshold for investors' minimum required return on utility stocks. Consistent with the Commission's recognition that its bond yield threshold is a "flexible test," the impact of widening equity risk premiums should be considered in evaluating low-end cost of equity estimates.[96]

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[91] Opinion No. 531 at P 147 (noting that "[t]he link between interest rates and risk premiums provides a helpful indicator of how investors' required returns on equity have been impacted by the interest rate environment").

[92] *Atl. Path 15, LLC*, 122 FERC ¶ 61,135 (2008) ("*Atlantic Path 15*").

[93] *Startrans IO, LLC*, 122 FERC ¶ 61,306 (2008) ("*Startrans*").

[94] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009) ("*Pioneer*").

[95] *SoCal Edison*, 131 FERC ¶ 61,020 at P 54.

[96] *Id.* at PP 54-56; Opinion No. 531 at P 122.

Q56. HOW DO YOU ADJUST THE COMMISSION'S 100 BASIS-POINT RISK PREMIUM?

A56. The Commission's findings in *SoCal Edison, Atlantic Path 15,* and *Startrans* all relied on a six-month study period ending in November 2007, while *Pioneer* referenced a six-month period ending September 2008. Based on data reported by Moody's, the average yield on Baa-rated public utility bonds over these two six-month periods was 6.69%, versus 4.13% for the six months ending September 2019. Meanwhile, the inverse relationship quantified on page 7 of Exhibit No. JCP-207 indicates that the equity risk premium increases by approximately 60 basis points for every 100 basis point drop in the Baa-rated public utility bond yield.

Accordingly, this evidence supports an upward adjustment to the 100 basis point risk premium that was adopted in *SoCal Edison* and *Pioneer* to recognize the impact of changes in public utility bond yields since the time those cases issued. Of course, should bond yields subsequently rise above the average levels on which the 100 basis point risk premium was originally predicated, this would imply a downward adjustment to the premium in applying the bond yield-based threshold in future proceedings.

Q57. WHAT ADJUSTMENT TO THE COMMISSION'S 100 BASIS-POINT RISK PREMIUM IS WARRANTED BASED ON THIS EVIDENCE?

A57. As shown in Table JCP-2, accounting for the implications of the decline in bond yields results in an upward adjustment to the bond yield-based threshold of 153 basis points:

TABLE JCP-2
ADJUSTMENT TO LOW-END THRESHOLD

(a) Historical Baa Bond Yield	6.69%
(b) Current Baa Bond Yield	4.13%
Change in Bond Yield	-2.56%
(c) Risk Premium/Interest Rate Relationship	-0.5990
Adjustment to Risk Premium	1.53%

(a) Average Baa utility bond yield for 6-mo. periods ending Nov. 2007 and Sep. 2008.
(b) Average Baa utility bond yield for 6-mo. ended Sep. 2019.
(c) Exhibit No. JCP-207 at p. 7.

In other words, adjusting the 100 basis point threshold to account for the increase to the equity risk premium that accompanies a fall in bond yields would result in a current, comparable risk premium of 253 basis points. Adding this premium to the 4.13% average yield on Baa utility bonds for the six months ending September 2019 results in a low-end threshold of 6.66%.

Q58. HOW DOES THIS TEST OF LOW-END VALUES IMPACT THE RESULTS OF THE DCF ANALYSIS?

A58. As shown on Exhibit No. JCP-204, this low-end threshold would exclude six values ranging from 0.74% to 6.52%. Even after these eliminations, retention of low-end values in the 7% range—which are far below any credible estimate of the cost of equity—still imparts a pronounced downward bias to the DCF results.

Q59. HOW HAS THE COMMISSION PROPOSED TO EVALUATE COST OF EQUITY ESTIMATES AT THE HIGH END OF THE RANGE?

A59. As noted in the Briefing Orders, the Commission has proposed to eliminate high-end cost of equity estimates that are "more than 150 percent of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied."[97]

Q60. DO YOU AGREE THAT THE 150% MEDIAN-BASED TEST ACHIEVES THE COMMISSION'S DESIRED OBJECTIVE WHEN APPLIED TO THE DCF MODEL?

A60. No. Application of the 150% high-end test is based on the misguided premise that the median of the DCF results presents a meaningful guide to investors' required returns for the proxy group companies. But, as the Commission correctly recognized in Opinion Nos. 531 and 551, the results of any DCF application can differ substantially from investors' expectations and are subject to potential distortion. As shown on Exhibit No. JCP-204, the median value resulting from the DCF approach is 9.01%, which falls well below the 9.39% and 9.29% thresholds that the Commission has already determined to be unjust and unreasonable.

Thus, the relevant facts do not support a finding that a DCF median value of 9.01% provides an objective basis to evaluate "a broad range of potentially lawful ROEs."[98] This confirms my conclusion that the dispersion of individual DCF values around a downward-biased measure of central tendency, as proposed in the Briefing Orders, is not a valid test of how well a specific DCF estimate reflects investors' expectations at the high end of the range.

Q61. THE COMMISSION'S DETERMINATION THAT 9.39% AND 9.29% WERE UNLAWFUL OUTCOMES WAS PREDICATED ON THE SPECIFIC CIRCUMSTANCES OF OPINION NOS. 531 AND 551. HAVE CAPITAL MARKET

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[97] Coakley Briefing Order at P 53; MISO Briefing Order at P 54.

[98] *Emera Maine*, 854 F.3d at 18, 24. *See also ISO New England Inc. v. Bangor Hydro-Elec. Co.*, 161 FERC ¶ 61,031 at P 8 (2017).

CONDITIONS CHANGED IN A MANNER THAT WOULD SUBSTANTIALLY ALTER THESE CONCLUSIONS?

A61. No. Table JCP-3 compares six-month average bond yields at the end of the six-month DCF study periods utilized in Opinion Nos. 531 and 551 with those during the six-month periods immediately prior to the date of the Commission's Opinion No. 531 and ending September 2019.[99]

TABLE JCP-3
COMPARISON OF YIELD BENCHMARKS

	(a)		(b)		(b)	
	Baa Utility		**30-Yr Treasury**		**10-Yr Treasury**	
Opinion No. 531	**%**	**Change**	**%**	**Change**	**%**	**Change**
Mar-13 (Record Period)	4.62%	--	3.00%	--	1.83%	--
May-14 (Opinion Issued)	4.98%	36	3.64%	64	2.77%	94
Sep. 2019	4.13%	-49	2.53%	-47	2.07%	24
Opinion No. 551						
Jun-15 (Record Period)	4.65%	--	2.72%	--	2.07%	--
Aug-16 (Opinion Issued)	4.55%	-10	2.48%	-24	1.70%	-37
Sep. 2019	4.13%	-52	2.53%	-19	2.07%	0

(a) Six-month average yield based on data reported by Moody's Investors Service.
(b) Six-month average yield based on data reported by the Federal Reserve.

As illustrated above, average yields on Baa-rated public utility bonds and 30-year Treasury bonds are approximately 20 to 50 basis points lower than those prevailing during the evidentiary periods considered in Opinion Nos. 531 and 551, while 10-year Treasury bond yields are largely unchanged. The Commission also noted in the Briefing Orders that

[99] The changes referenced in Table JCP-3 are basis point changes relative to the values for the respective record periods corresponding to Opinion Nos. 531 and 551.

the prime interest rate provides guidance as to "indications of a change in capital market conditions."[100] Since the record periods considered in Opinion Nos. 531 and 551, the prime interest rate has increased from 3.25% to 5.15%.[101] These interest rate benchmarks, which serve as an objective guide for both the direction and magnitude of changes in investors required rate of return, do not support a finding that the 9.01% DCF median value provides an objective basis to evaluate "a broad range of potentially lawful ROEs."[102] This also confirms my conclusion that the dispersion of individual DCF values around a downward-biased measure of central tendency, as proposed in the Briefing Orders, is not a valid test of how well a specific DCF estimate reflects investors' expectations at the high end of the range.

Q62. WHAT OTHER LOGICAL CONSIDERATION MILITATES AGAINST A HIGH-END TEST BASED ON THE MEDIAN OF THE DCF RESULTS?

A62. Ultimately, the potential reasonableness of any cost of equity estimate is not tied to the methodology used to derive it; rather, it is predicated on the plausible range of investors' required returns for the companies in the proxy group. As a result, it would be illogical to find, for example, that a value of 15% is acceptable in framing the zone of reasonable estimates under the Expected Earnings approach, while simultaneously holding that a DCF cost of equity of 12% is excessive. Similarly, in evaluating illogical low-end values, the Commission applies a single test uniformly across multiple financial methodologies.

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[100] Coakley Briefing Order at P 29; MISO Briefing Order at P 31.

[101] Board of Governors of the Federal Reserve System (US), Bank Prime Loan Rate [MPRIME], retrieved from FRED, Federal Reserve Bank of St. Louis, *available at* https://fred.stlouisfed.org/series/MPRIME.

[102] *Emera Maine*, 854 F.3d at 18, 24. *See also ISO New England Inc. v. Bangor Hydro-Elec. Co.*, 161 FERC ¶ 61,031 at P 8.

Q63. WHAT IS THE REAL IMPACT OF APPLYING THE 150% MEDIAN-BASED THRESHOLD TO THE RESULTS OF THE COMMISSION'S TWO-STEP DCF METHOD?

A63. The real impact is to artificially narrow the ROE zone by collapsing the range of "acceptable" values down towards the biased median of the overall DCF results. While the whole point of a DCF analysis is to *estimate* investors' required rate of return, the 150% "test" of high-end results turns this entire process on its head by using an arbiter of reasonableness that is predicated on a method the Commission has characterized as "inaccurate" and has determined "may not capture how investors evaluate utility returns."[103]

Q64. BASED ON THIS ANALYSIS, WHAT TEST OF HIGH-END VALUES DO YOU RECOMMEND?

A64. Given the fact that the plausibility of any cost of equity estimate is independent of the methodology used to derive it, if the Commission were to apply a median-based test, it should apply a uniform test of high-end estimates based on 150% of the *highest* overall median value produced by the DCF, ECAPM, and Expected Earnings methodologies. Although lacking any link to objective evidence regarding the range of returns required by investors, such a test would at least be logically consistent (i.e., establish a single standard to evaluate high-end values across all three financial models). It would also avoid the failings of relying on a distorted DCF median value, and would be more consistent with the findings of the Commission and the courts, which have recognized that "the zone of reasonableness creates a broad range of potentially lawful ROEs,"[104]

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[103] Coakley Briefing Order at PP 45-46; *see also* MISO Briefing Order at 42.

[104] *ISO New England Inc. v. Bangor Hydro-Elec. Co.*, 161 FERC ¶ 61,031 at P 8 (2017) (citing *Emera Maine*, 854 F.3d at 26).

As shown on Exhibit No. JCP-206, the overall median produced by the Expected Earnings approach is 10.65%. Multiplying this value by the Commission's 150% factor results in a high-end threshold of 15.98%. As a point of reference, this threshold is approximately 170 basis points lower than the 17.7% high-end threshold that the Commission applied until Opinion No. 531.[105]

Q65. WHAT OTHER CONSIDERATION HAS THE COMMISSION RAISED IN EVALUATING COST OF EQUITY ESTIMATES AT THE HIGH END OF THE RANGE?

A65. The Briefing Orders also suggested that cost of equity estimates at the upper end of the range should be subject to a "natural break" analysis, based on the difference between individual values and the next-lowest estimate.[106]

Q66. DO YOU AGREE THAT THE DIFFERENCE BETWEEN INDIVIDUAL COST OF EQUITY ESTIMATES CAN BE USED AS A GAUGE OF REASONABLENESS?

A66. No. The dispersion between a particular cost of equity result and the next lowest value provides no relevant information in evaluating the reasonableness of estimates at the upper end of the range. In fact, the exact same argument was raised by the petitioners in Docket No. EL11-66 regarding the ROE for the NETOs and was rejected by the Commission. As summarized in Opinion No. 531:

> Petitioners next argue that, if the Commission eliminates PSEG as a low-end outlier, it must also eliminate UIL Holdings as a high-end outlier because UIL Holdings' DCF result is 112 basis points above the next highest DCF result, and the Commission must apply the same "natural break" analysis in both the low-end and high-end outlier tests. We disagree. *The low-end outlier test and the high-end outlier test serve very different purposes*: the low-end outlier test is intended to screen out companies whose ROE estimates are low enough that an investor would consider the

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[105] *See* Opinion No. 531 at P 115.

[106] Coakley Briefing Order at P 53; MISO Briefing Order at P 54.

> stock to yield essentially the same return as debt,[107] whereas the high-end outlier test is intended to screen out companies whose growth rates are unsustainably high and therefore fail a threshold test of economic logic.[108]

Q67. WHAT IS THE FUNDAMENTAL FLAW IN THE NOTION OF A "NATURAL BREAK" TEST?

A67. Such a "test" represents a misappropriation of statistical concepts based on the false premise that evaluating individual DCF cost of equity estimates is akin to statistical sampling. It is not.

Q68. PLEASE EXPLAIN.

A68. The notion of "outliers" that underlies such an approach relates to the practice of sampling, which is concerned with the selection of a subset of data from within a larger population that allows the researcher to make statistical inferences about unknown qualities of the population. If a sample is chosen properly, characteristics of the entire population from which the sample is drawn can be estimated from corresponding characteristics of the sample. While sampling theory is of great value in many situations, it has no relevance in evaluating the individual cost of equity results produced by the DCF, ECAPM, or Expected Earnings methodologies for the proxy companies.

The key fallacy underlying this misuse of statistical concepts is that estimating the cost of equity does not involve a process of sampling at all. On the contrary, through application of proxy group criteria, the Commission has identified *all* of the utilities deemed to be of comparable risk to JCP&L. In other words, the array of cost of equity estimates produced by the ROE analyses represent the *population*, not a sample of the

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[107] *See S. Cal. Edison Co.*, 92 FERC ¶ 61,070 at 61,266 (2000).

[108] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 79 (2015) (footnotes omitted).

population. We are not drawing 20 colored marbles from an urn containing hundreds and seeking to make inferences regarding the makeup of the unobserved remainder. Rather, we are analyzing all of the marbles (or all of the relevant, comparable risk companies). As a result, the dispersion of individual values is not a valid test of how well a specific cost of equity estimate reflects investors' expectations and required returns.

Q69. MEASURES OF DISPERSION ARE COMMONLY REFERENCED FOR POPULATIONS. WHAT IS THE DISTINCTION HERE?

A69. The key distinction is the difference between *descriptive* and *inferential* statistics. There is nothing inherently "wrong" about referencing measures of dispersion as a way to describe and summarize the underlying data. These are simply statistical statements about the nature of the population itself. But rather than confining this reference to descriptive measures, reference to a "natural break" wrongly suggests that relative dispersion can be used to make *inferences* about the reasonableness of individual data points in the population.

Consider the example of a college professor who is interested in the profile of the students in her class. As part of an anonymous questionnaire at the beginning of each semester, she routinely asks the students to report their family's approximate net income in the prior year, with the hypothetical responses being summarized below:

TABLE JCP-4
DISTRIBUTION OF FAMILY INCOME

	Fall Semester		Spring Semester	
	Reported Income	**Difference From Next Highest**	**Reported Income**	**Difference From Next Highest**
1	$ 22,000	$ -	$ 25,000	$ -
2	$ 31,000	$ 9,000	$ 25,000	$ -
3	$ 38,000	$ 7,000	$ 31,000	$ 6,000
4	$ 42,000	$ 4,000	$ 43,000	$ 12,000
5	$ 51,000	$ 9,000	$ 47,000	$ 4,000
6	$ 65,000	$ 14,000	$ 58,000	$ 11,000
7	$ 81,000	$ 16,000	$ 62,000	$ 4,000
8	$ 86,000	$ 5,000	$ 71,000	$ 9,000
9	$ 91,000	$ 5,000	$ 82,000	$ 11,000
10	$ 105,000	$ 14,000	$ 105,000	$ 23,000
11	$ 118,000	$ 13,000	$ 118,000	$ 13,000
12	$ 121,000	$ 3,000	$ 210,000	$ 92,000
13	$ 140,000	$ 19,000	$ 350,000	$ 140,000
14	$ 143,000	$ 3,000	$ 489,000	$ 139,000
15	$ 553,000	$ 410,000	$ 553,000	$ 64,000

While the dispersion of the individual results gives the professor one way to characterize income disparities between the 15 students in her class, it doesn't allow her to make inferences regarding the reasonableness of the responses. Based on the notion of a "natural break," however, the professor would presumably reject the reported income level of $553,000 in the fall semester as an unreliable "outlier" solely because it is $410,000 higher than the next lowest value. On the other hand, this same "test" would retain the exact same observation in the spring semester. Similarly, the measure of dispersion from one observation to another provides no basis to judge the reasonableness of any single cost of equity estimate.

Moreover, the goal in evaluating the results of the DCF, ECAPM, and Expected Earnings approaches is not to identify "outliers," it is to remove estimates that are clearly illogical for purposes of identifying the "broad range of potentially lawful ROEs" that constitutes the zone of reasonableness. The identification of clearly illogical results should be a case specific determination relying on the specific evidence at hand. The notion of an "outlier" in the context of statistics and sampling theory is an entirely separate concept from the evaluation of DCF estimates for the population of comparable risk utilities. Apart from the fact that the arithmetic difference between two individual cost of equity estimates does not provide a sound basis to evaluate the economic validity of either value, the amount of any "break" that might be suggestive of an "outlier" is arbitrary and lacks any evidentiary foundation.

Q70. WHAT RESULTS ARE PRODUCED USING THE CONSTANT GROWTH DCF MODEL?

A70. Application of the constant growth DCF model employing the same evaluation of low and high-end values discussed previously is presented in Exhibit No. JCP-204. As shown there, this analysis results in a range of 6.87% to 14.93%, with a median of 9.01% and a midpoint of 10.90%.

B. Empirical CAPM

Q71. PLEASE DESCRIBE THE ECAPM.

A71. The ECAPM approach is an expanded version of the CAPM, which is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

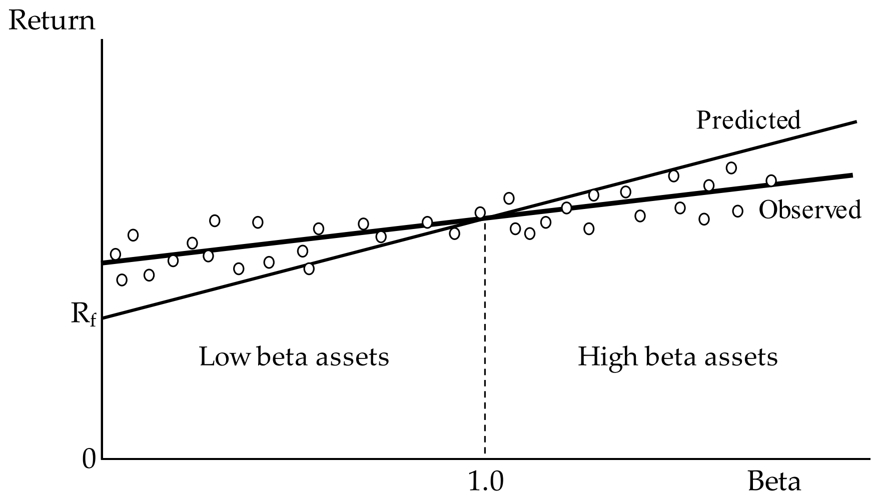
where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and
B_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM and ECAPM are *ex-ante*, or forward-looking, models based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the ECAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q72. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A72. Empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn somewhat less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower returns than predicted by the CAPM. This is illustrated graphically in the figure below:

FIGURE JCP-1
CAPM – PREDICTED VS. OBSERVED RETURNS



Because the betas of utility stocks, including those in the proxy group, are generally less than 1.0, this fact implies that cost of equity estimates based on the traditional CAPM would understate the cost of equity for electric utilities. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[109]

Based on a review of the empirical evidence, *New Regulatory Finance* concluded that the relationship between the expected return on a security and its risk is represented by the following ECAPM formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

[109] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 189.

This equation, and the associated weighting factors, recognizes the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

Q73. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF VALUE LINE BETAS?

A73. Yes. Value Line beta values are adjusted for the observed tendency of beta to converge toward the mean value of 1.00 over time.[110] The purpose of this adjustment is to refine beta values determined using historical data to better match forward-looking estimates of beta, which are the relevant parameter in applying the CAPM or ECAPM models. Meanwhile, the ECAPM does not involve any adjustment to beta whatsoever. Rather, it represents a formal recognition of findings in the financial literature that the observed risk-return tradeoff illustrated in Figure JCP-1 is flatter than predicted by the CAPM. In other words, even if a firm's beta value were estimated with perfect precision, the CAPM would still understate the return for low-beta stocks and overstate the return for high-beta stocks.[111] The ECAPM and the use of adjusted betas represent two separate and distinct issues in estimating returns.

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[110] *See, e.g.*, Marshall E. Blume, *Betas and Their Regression Tendencies*, Journal of Finance (Jun. 1975) at 785-95.

[111] The use of adjusted beta is also documented in the financial research supporting the development of the ECAPM. *See* Robert Litzenberger, Krishna Ramaswamy, and Howard Sosin, *On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital*, J. Fin. 369-83 (May 1980) (cited by Morin, *New Regulatory Finance*, at 189-90).

Q74. HAVE OTHER REGULATORS RELIED ON THE ECAPM?

A74. Yes. The ECAPM approach has been relied on by the Staff of the Maryland Public Service Commission ("MDPSC"). For example, an MDPSC Staff witness noted that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluded that, "I believe under current economic conditions that the ECAPM gives a more realistic measure of the ROE than the CAPM model does."[112] The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.[113]

Similarly, the Montana Public Service Commission more recently concluded that "[t]he evidence in this proceeding has convinced the Commission that the Empirical Capital Asset Pricing Model ("ECAPM") should be the primary method for estimating the [utility's] cost of equity."[114]

The staff of the Colorado Public Utilities Commission has also recognized that, "[t]he ECAPM is an empirical method that attempts to enhance the CAPM analysis by flattening the risk-return relationship,"[115] and relied on the exact same standard ECAPM

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[112] *Direct Testimony and Exhibits of Julie McKenna*, Maryland PSC Case No. 9299 (Oct. 12, 2012) at 9.

[113] Regulatory Commission of Alaska, Order No. P-97-004(151) at 146 (Nov. 27, 2002).

[114] Mont. Pub. Serv. Comm'n, Order No. 7575c at P114 (Sept. 26, 2018).

[115] *Answering Testimony and Exhibits of Scott England*, Proceeding No. 13AL-0067G, (July 31, 2013) at 47.

equation presented above.[116] The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has also relied on this same ECAPM formula in estimating the cost of equity for a natural gas utility, as have witnesses for the Office of Arkansas Attorney General.[117]

Q75. HOW DO YOU APPLY THE ECAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A75. My application of the ECAPM to the proxy group is based on a forward-looking estimate for investors' required rate of return from common stocks, consistent with the approach considered by the Commission in establishing a just and reasonable ROE in Opinion Nos. 531 and 551.[118] In order to capture the expectations of today's investors in current capital markets, the expected market rate of return is estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

I obtain the dividend yield for each company from Value Line. The growth rate is equal to the average of the earnings per share growth projections for each firm published by IBES and Value Line, as utilized in Opinion No. 551,[119] with each company's dividend yield and growth rate weighted by its proportionate share of total market value. Based on the weighted average of the projections for the individual firms, these estimates imply an average growth rate over five years of 9.72%. Combining this average growth rate with a year-ahead dividend yield of 2.41% results in a current cost of common equity estimate for

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[116] *Id.* at 48.

[117] *Pre-Filed Direct Testimony of Anthony J. Ornelas*, Docket No. 30011-97-GR-17, (May 1, 2018) at 52-53; *Direct Testimony of Marlon F. Griffing, PH.D.*, Docket No. 17-071-U, (May 29, 2018) at 33-35.

[118] Opinion No. 531 at PP 146-147, n.292; Opinion No. 551 at PP 165-71.

[119] Opinion No. 551 at P 169.

the market as a whole (R_m) of 12.13%. Subtracting a 2.53% risk-free rate based on the six-month average yield on 30-year Treasury bonds at September 2019 produces a market equity risk premium of 9.60%.

Q76. WHY DID YOU INCORPORATE VALUE LINE GROWTH RATES IN ESTIMATING THE MARKET RATE OF RETURN USED TO APPLY THE ECAPM?

A76. Investors' growth expectations are unobservable and there is no perfect proxy that exactly replicates the net impact of the disparate views impounded into the stock prices established in the capital markets. Thus, while IBES growth estimates published by *Yahoo! Finance* represent one credible source of information, there is no basis to conclude that these growth projections are inherently superior to those available from other, well recognized financial data platforms. Reliance on both IBES and Value Line growth rates when estimating the market rate of return recognizes the importance of examining multiple sources and approaches to evaluate investors' growth expectations in order to reduce error and enhance confidence in the reliability of the ECAPM results.

Moreover, Value Line's growth projections provide a meaningful guide to investors' expectations. Value Line is recognized as being the most widely available source of investment information to investors, and there are many citations to sources supporting its usefulness as a guide to investors' expectations.[120] Value Line provides an

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[120] *See, e.g.*, Opinion No. 531 at P 102 (noting that Value Line is "a widely-followed, independent investor service" that has been "shown to be reliable and commonly relied upon by investors."); *Kern River Gas Transmission Co.*, Opinion No. 486-C, 129 FERC ¶ 61,240, at PP 50, 91 (2009) ("Because Value Line is a publication relied on by many investors, its statements concerning the relative risks of different energy-related investments is highly probative of the views of investors generally.") (prior and subsequent history omitted); *Sw. Pub. Serv. Co.*, 83 FERC ¶ 61,138, at 61,636 n.63 (1998) ("The Commission did not, however, intend to preclude consideration of contemporaneous growth estimates made by the various investor services companies (e.g., Value

extensive analysis underpinning the analysts' assessments of individual EPS growth rate projections. As a result, Value Line EPS growth rates are immune from any potential errors involved in the compilation of survey data and avoid uncertainties as to the veracity of the assumptions underlying the projected values.

In addition to its depth of support, Value Line's sole business is to provide independent and unbiased investment guidance to its subscribers. Because Value Line does not engage in securities trading or investment banking activities, there is no potential for conflicts of interest within the operating divisions of the investment firm that could arguably influence its analysts' growth estimates. As a result, Value Line growth data can provide an important check on the reliability of IBES-based DCF results. For example, *New Regulatory Finance* endorsed a similar approach, noting that one way to assess the concern that consensus analysts' forecasts such as IBES may be biased "is to incorporate into the analysis the growth forecasts of independent research firms, such as Value Line, in addition to the analyst consensus forecast."[121]

Q77. HAS THE COMMISSION RELIED ON A MARKET RATE OF RETURN THAT CONSIDERS BOTH IBES AND VALUE LINE GROWTH RATES?

A77. Yes. While Opinion No. 551 rejected the use of Value Line growth rates in applying the two-step DCF model to estimate the cost of equity for electric utilities,[122] the Commission

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Line, Zack's Investment Research, Inc. (Zack's), Institutional Brokers Estimate System (IBES)), as investors rely on these estimates in their decision-making process.").

[121] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 300.

[122] Opinion No. 551 at P 62.

also concluded that "use of both IBES and Value Line growth rate estimates in [the] CAPM analysis is reasonable . . . ."[123]

Q78. THE COMMISSION DETERMINED THAT IBES GROWTH RATES ARE SUPERIOR TO VALUE LINE ESTIMATES BECAUSE THEY REFLECT A CONSENSUS AND ARE UPDATED MORE FREQUENTLY.[124] DO YOU AGREE WITH THIS CONCLUSION?

A78. No. While Value Line projections are sometimes portrayed as reflecting only the opinions of a single analyst, this is not a complete characterization. Even though the commentary and projections included in Value Line's reports for the individual firms that it covers are sponsored by a single analyst, they are developed under a common, proprietary analytical framework that is supported by a network of analysts within the Value Line organization, and are reviewed by an internal panel of other analysts prior to publication. This view is supported by prior testimony of the Trial Staff:

> Q. Does that Value Line report indicate the views of one analyst?
>
> A. No. Although the report may have been authored by one individual analyst, Value Line analysts interact through a committee that reviews and monitors their analyses and conclusions. The resulting projections are supported by a team, and reflect more than the views of one individual.[125]

Given the Commission's recognition that many of the "consensus" growth rates used to apply the DCF model are, in fact, dependent on the forecast of a single contributing

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[123] *Id.* at P 169.

[124] *Id.* at P 64.

[125] *Prepared Direct and Answering Testimony of Commission Trial Staff Witness Douglas M. Green,* Docket No. EL17-76-001, Exhibit No. S-001 at 138 (Sep. 21, 2018) (emphasis in original); *accord Prepared Direct and Answering Testimony of Commission Staff Witness Douglas M. Green*, Docket No. EL15-8-000, Exhibit No. S-1 at 14 (June 30, 2015).

analyst,[126] there is no meaningful basis to reject Value Line's EPS growth projections on this basis.

In addition, *Yahoo! Finance* does not make public any indication as to the vintage of the consensus growth rates it publishes, or of the underlying data used to construct them, and the Commission has not required that such estimates meet a particular "freshness" policy.[127] In contrast, the analyses and reports supporting Value Line's projected EPS growth rates are updated on a scheduled basis, which removes debate about any potential "staleness" of the underlying data.

Moreover, just as the Commission recognized the importance of expanding its ROE approach to include information used by investors to inform their decisions,[128] Value Line's growth rate projections provide a sound basis on which to evaluate the forward-looking market return used in the ECAPM. Value Line is recognized as being the most widely available source of investment information to investors and there are many citations to textbooks and other sources supporting its usefulness as a guide to investors' expectations. For example, *Cost of Capital – A Practitioners' Guide*, published by the Society of Utility and Regulatory Financial Analysts, noted that:

> [A] number of studies have commented on the relative accuracy of various analysts' forecasts. Brown and Rozeff (1978) found that Value Line was superior to other forecasts. Chatfield, Hein and Moyer (1990, 438) found, further "Value Line to be more accurate than alternative forecasting

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[126] Coakley Briefing Order at P 47.

[127] *See, e.g.,* Opinion No. 531 at P 81 (citing Staff's arguments that certain estimates from *Yahoo! Finance* were "unreliable and stale.") PP 88, 89 (adopting IBES growth rates published by *Yahoo! Finance*).

[128] *Id.* at P 147.

> methods" and that "investors place the greatest weight on the forecasts provided by Value Line."[129]

New Regulatory Finance concluded that:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors.[130]

Value Line is clearly a "widely-followed, independent investor service,"[131] and the returns on equity projected by Value Line provide a credible guide to investors' expectations and their use, along with IBES growth estimates, enhances the estimate of the expected return on the market.

Q79. WHAT IS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE ECAPM?

A79. I rely on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. While the Commission has expressed reservations in the past due to the fact that beta is measured based on historical stock prices, the long track record of published values supports the conclusion that Value Line's betas provide a good predictor of future stock price behavior relative to the market. As noted in *New Regulatory Finance*:

> Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[132]

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[129] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Soc'y of Util. & Regulatory Fin. Analysts (2010) at 143.

[130] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 71.

[131] Opinion No. 531 at P 102. *See also Kern River Gas Transmission Co.*, Opinion No. 486-C, 129 FERC ¶ 61,240 at P 50 (2009) (noting that "Value Line is a publication relied on by many investors. . . .").

[132] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 71.

The fact that investors rely on Value Line betas in evaluating expected returns for utility common stocks provides strong support for this approach.

Q80. DO YOU INCLUDE A SIZE ADJUSTMENT IN APPLYING THE ECAPM?

A80. Yes. Because financial research indicates that beta does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect. As explained by Morningstar:

> One of the most remarkable discoveries of modern finance is the finding of a relationship between firm size and return. On average, small companies have higher returns than large ones . . . . The relationship between firm size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks.[133]

According to the theory underlying the ECAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, my ECAPM analyses incorporate an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the companies in the proxy group.

Q81. WHAT ROE IS IMPLIED USING THE ECAPM APPROACH?

A81. As shown on page 1 of Exhibit No. JCP-205, application of the forward-looking ECAPM approach implies a cost of equity range of 8.31% to 11.53% with a median and midpoint cost of equity of 10.07% and 9.92%, respectively.

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[133] Morningstar, *2015 Ibbotson SBBI Classic Yearbook*, at 99.

Q82. IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE ECAPM AND RISK PREMIUM METHODS?

A82. Yes. Despite more recent declines in bond yields, as illustrated in the table below, widely-referenced forecasts continue to document expectations for interest rates to rise from current levels.

TABLE JCP-5
INTEREST RATE TRENDS

	Sep. 2019	Average 2020-24	Change (bp)
10-Yr. Treasury	2.07%	3.15%	108
30-Yr. Treasury	2.53%	3.34%	81
Aaa Corporate	3.35%	4.00%	65
Aa Utility	3.56%	5.01%	145

Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 30, 2019).
IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019).
Energy Information Administration, Annual Energy Outlook 2019 (Jan. 24, 2019).
Wolters Kluwer, Blue Chip Financial Forecasts (Jun. 1, 2019).

Accordingly, in addition to the use of historical average bond yields, I also applied the ECAPM and Risk Premium methods based on projections for bond yields over the 2020-2024 horizon. This is consistent with the Commission's proposed findings for the Risk Premium method in the Coakley Briefing Order, which relied on an average of the results based on historical and projected interest rates.[134]

[134] Coakley Briefing Order at P 59 n.115.

Q83. WHAT ECAPM COST OF EQUITY ESTIMATES ARE PRODUCED AFTER INCORPORATING FORECASTED BOND YIELDS?

A83. As shown on page 2 of Exhibit No. JCP-205, applying the ECAPM using a forecasted Treasury bond yield for 2020-2024 implies an ROE range of 8.71% to 11.66%, with a median of 10.33% and a midpoint of 10.19%.

C. Expected Earnings Approach

Q84. PLEASE EXPLAIN YOUR EXPECTED EARNINGS STUDY.

A84. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This approach is consistent with the economic underpinnings for a fair rate of return, as reflected in the comparable earnings test established by the Supreme Court in *Hope* and *Bluefield.* Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors. As the Commission recognized in Opinion No. 531:

> [T]he . . . expected earnings analysis, given its close relationship to the comparable earnings standard that originated in *Hope*, and the fact that it is used by investors to estimate the ROE that a utility will earn in the future can be useful in validating our ROE recommendation.[135]

Q85. HAS THE EXPECTED EARNINGS APPROACH BEEN RECOGNIZED AS A MEANINGFUL METHODOLOGY IN EVALUATING A JUST AND REASONABLE ROE?

A85. Yes. The Expected Earnings approach is directly analogous to the comparable earnings method that predominated before the advent of the DCF and other financial models. The

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[135] Opinion No. 531 at P 147.

traditional comparable earnings method identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test was often implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment. Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison, and it has long been referenced and relied on in regulatory proceedings. For example, a 1991 survey conducted by NARUC reported that 19 regulatory jurisdictions cited the comparable earnings approach as a primary method favored in determining the allowed ROE, while an additional 16 jurisdictions reported that this approach was considered along with the results of other methods.[136] Similarly, the VSCC is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region, which establish lower and upper boundaries for the allowed ROE.[137]

Moreover, regulators do not set the returns that investors earn in the capital markets—they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable

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[136] Nat'l Ass'n of Regulatory Util. Comm'rs, *Utility Regulatory Policy in the U.S. and Canada, 1995-1996* (Dec. 1996).

[137] In orders issued on November 7, 2018 and November 30, 2011 in Case Nos. PUR-2018-00048 and PUE-2011-00037, for example, the VSCC established the allowed ROE for Appalachian Power Company based on the earned returns on book value for a peer group of other electric utilities.

risk will earn on invested capital. This opportunity-cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

A textbook prepared for the Society of Utility and Regulatory Financial Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods,"[138] and notes that the comparable earnings method is "easily understood" and firmly anchored in the regulatory economics underlying the *Bluefield* and *Hope* cases. It also notes that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods. *New Regulatory Finance* concluded that, "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[139]

Q86. DOES THE INVESTMENT COMMUNITY REFERENCE EARNED RETURNS ON BOOK VALUE IN THEIR EVALUATION OF ELECTRIC UTILITIES?

A86. Yes. S&P cited the relevance of earned returns on book value in highlighting the primary credit considerations in the utility industry, noting that "required rate of return on equity

[138] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Society of Utility and Regulatory Financial Analysts (2010) at 115-16.

[139] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 396.

investment is closely linked to a utility company's profitability."[140] S&P indicated that, "[f]or regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity."[141] While recognizing that "the regulator ultimately bases its decision on an authorized ROE," S&P observed that "different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE."[142] In other words, in S&P's view, the earned return on book value may provide better insight into the financial health of the utility because it reflects the end-result of regulation, not the theoretical outcome implied by an authorized ROE. Consistent with this paradigm, S&P recently examined trends in utility returns on book equity, as compared with authorized ROEs, in evaluating financial performance for the electric utility industry.[143]

Moody's also recognizes the relevance of returns on book value in its assessment of a utility's future prospects. While noting that "[t]he authorized ROE is a popular focal point in many regulatory rate case proceedings," Moody's recognized that "earned ROEs, as reported by utilities and adjusted by Moody's," are a key gauge of financial

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[140] Standard & Poor's Corporation, *Utilities: Key Credit Factors For The Regulated Utilities Industry,* Criteria Corporates (Nov. 19, 2013).
[141] *Id.*
[142] *Id.*
[143] S&P Global Ratings, *Utility-earned ROEs exceeded authorized since 2016, but 2019 may not match 2018*, Financial Focus (Jun. 10, 2019).

performance.[144] As Moody's concluded, "utilities are closer to earning their authorized equity returns, which is positive from an equity market valuation perspective."[145]

Similarly, in a publication entitled "Industry Surveys, Electric Utilities," CFRA[146] highlighted the relevance of returns on book equity to investors in a section entitled, "How to Analyze a Company in this Industry."

> Return on Equity
> If a utility's ROE is too low, the analyst must determine if it was caused by mild weather or the absence of a needed rate hike—or if the utility is poorly operated. Conversely, an ROE that is too high could cause regulators to seek a rate cut. For firms in the S&P Composite 1500 electric utilities index, the average ROE generally ranges between 10% and 13%, although the average has trended lower in the past few years.[147]

Q87. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR ELECTRIC UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A87. The year-end returns on common equity projected by Value Line over its forecast horizon for each of the utilities in the proxy group are shown on Exhibit No. JCP-206. In *Southern California Edison Co.*, the Commission correctly recognized that if the rate of return were based on end-of-year book values, such as those reported by Value Line, it would understate actual returns because of growth in common equity over the year.[148] Accordingly, consistent with the Commission's findings and the theory underlying this approach, I made

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[144] Moody's Investors Service, *Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles*, Sector In-Depth 5 (Mar. 10, 2015).

[145] *Id.*

[146] CFRA is one of the world's largest providers of institutional-grade independent investment research and acquired the equity and fund research arm of Standard & Poor's Corporation in October 2016.

[147] CFRA, *Electric Utilities*, Industry Surveys (Aug. 2018) at 50.

[148] *S. Cal. Edison Co.*, 92 FERC ¶ 61,070 at 61,263 & n.38.

an adjustment to compute an average rate of return.[149] The Commission accepted this adjustment in Opinion No. 531-B and the Briefing Orders.[150]

As shown on Exhibit No. JCP-206, applying a low-end test described earlier would result in an Expected Earnings range of 8.20% to 14.60%. The median is 10.75% and the midpoint is 11.40%.

D. Risk Premium Approach

Q88. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A88. The Risk Premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the yield on bonds. Like the DCF model, the Risk Premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, Risk Premium methods directly estimate investors' required rate of return by adding an equity risk premium to bond yields.

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[149] Use of an average return in developing the rate of return is well supported. *See*, *e.g.*, Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 305-06 (discussing the need to adjust Value Line's end-of-year data, consistent with the Commission's prior findings).

[150] Opinion No. 531-B at P 126 (finding that adjustment "appropriately converts the proxy companies' earnings to reflect average returns"); *see also Coakley v. Bangor-Hydro-Elec. Co.*, 166 FERC ¶ 61,013 at P 8 (2019) (clarifying that the Coakley Briefing Order applied the same Expected Earnings approach accepted in Opinion Nos. 531 and 531-B, subject to the new high-end test that it proposed in the Briefing Order).

Q89. IS THE RISK PREMIUM METHOD A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A89. Yes. The Risk Premium method is based on the fundamental risk-return principle that is central to finance. This method is routinely referenced by the investment community, by academics, and in regulatory proceedings, and serves as an important tool in estimating a just and reasonable ROE for JCP&L.

Q90. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE MERITS OF THIS RISK PREMIUM APPROACH?

A90. Yes. The Commission's decisions in Opinion Nos. 531 and 551 adopted the risk premium approach as an informative indicator of investors' required rate of return.[151] Most recently, in the Briefing Orders the Commission affirmed its intention to consider the results of the Risk Premium method as one of the four financial models underlying its ROE methodology.[152] I am recommending the same approach in this proceeding. The Coakley Briefing Order relied on the average of the Risk Premium method's results incorporating historical bond yields and forecast bond yields.[153]

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[151] Opinion No. 531 at P 146; Opinion No. 551 at P 191.

[152] The Commission has previously considered the Risk Premium method in evaluating a just and reasonable ROE, including the risk premium approach. *See, e.g.*, *Distrigas of Mass. Corp.*, Opinion No. 291, 41 FERC ¶ 61,205 at 61,550 (1987) ("The DCF methodology, which we endorse, is but one analytical tool. A risk premium analysis . . . will also be considered. The weight to be given the results of each such methodology rests on the accuracy and sensibleness of the judgmental [inputs] and factors that the respective witnesses employed.").

[153] *See* Coakley Briefing Order at P 59 & n.115 (averaging the 10.7% result of the NETOs' Risk Premium study using historical bond yields with the 10.8% result of the NETOs' Risk Premium study using forecasted bond yields); *see also* Exhibit No. NET-704 at 1-2, included within Accession No. 20130417-5160, Docket No. EL11-66 (Apr. 17, 2013) (showing results of the NETOs' Risk Premium studies using both current and projected bond yields).

Q91. HOW DO YOU IMPLEMENT THE RISK PREMIUM METHOD?

A91. As in Opinion Nos. 531 and 551, I base my estimates of equity risk premiums for utilities on a study of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q92. HOW DO YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED ROES?

A92. I apply the risk premium approach directly using ROEs approved by the Commission for electric utilities since 2006, after the Energy Policy Act of 2005 was enacted. This is the same approach that the Commission relied on in its evaluation of a just and reasonable ROE in Opinion Nos. 531 and 551.[154] On page 3 of Exhibit No. JCP-207, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 2006 and 2018. As shown there, these equity risk premiums for electric utilities average 4.89%, and the yield on public utility bonds average 5.53%.

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[154] Opinion No. 531 at PP 146-47; Opinion No. 551 at P 191.

Q93. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A93. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Therefore, when implementing the Risk Premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set. As the Commission has concluded, "[t]he link between interest rates and risk premiums provides a helpful indicator of how investors' required returns on equity have been impacted by the interest rate environment."[155]

Q94. WHAT ARE THE IMPLICATIONS OF THIS RELATIONSHIP UNDER CURRENT CAPITAL MARKET CONDITIONS?

A94. Given that bond yields have remained relatively low and that equity risk premiums move inversely with interest rates, there is an implied increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

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[155] Opinion No. 531 at P 147.

Q95. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM METHOD USING HISTORICAL BOND YIELDS?

A95. I conduct a standard linear regression analysis to determine the relationship between interest rates and equity risk premiums. Based on the regression output between the interest rates and equity risk premiums displayed on page 7 of Exhibit No. JCP-207, the equity risk premium for electric utilities increased approximately 60 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. JCP-207, with an average six-month historical yield on Baa-rated public utility bonds at September 2019 of 4.13%, this implied a current equity risk premium of 5.73% for electric utilities. Adding this equity risk premium to the average six-month historical yield on Baa-rated public utility bonds implies a current cost of equity of 9.86%.

Q96. WHAT RISK PREMIUM COST OF EQUITY ESTIMATE IS PRODUCED AFTER INCORPORATING FORECASTED BOND YIELDS?

A96. As shown on page 2 of Exhibit No. JCP-207, incorporating a forecasted yield for 2020-2024 and adjusting for changes in interest rates since the study period implies an equity risk premium based on Commission-authorized ROEs of 4.83% for electric utilities. Adding this equity risk premium to the implied average yield on Baa-rated public utility bonds for 2020-2024 of 5.63% results in an implied cost of equity of 10.46%.

The average of this result and the 9.86% Risk Premium cost of equity based on historical bond yields is 10.16%.[156]

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[156] *See* Exhibit No. JCP-202.

V. LOW RISK NON-UTILITY DCF MODEL

Q97. WHAT OTHER PROXY GROUP DO YOU CONSIDER IN EVALUATING A JUST AND REASONABLE ROE FOR JCP&L?

A97. Consistent with underlying economic and regulatory standards, I also apply the DCF model to a select group of low-risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Group."

Q98. WHY DO YOU INCLUDE A DCF ANALYSIS FOR THIS NON-UTILITY GROUP?

A98. The primary reason I have examined DCF results for this Non-Utility Group is that utilities, such as JCP&L, need to compete with non-regulated firms for capital. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. The total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there is a wide range of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk.[157] Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

Q99. WHAT AUTHORITY CAN YOU POINT TO FOR CONSIDERING THE RETURNS OF UNREGULATED ENTITIES?

A99. Going as far back as the *Bluefield* and *Hope* cases, it has been accepted practice to consider required returns for non-utility companies, and with sound justification. Returns in the competitive sector of the economy form the very underpinning for utility ROEs because

[157] Even for a single utility, capital will be allocated between competing uses in part based on opportunity costs. Where the utility has no regulatory obligation to undertake a particular project, an anemic return may foreclose investment altogether.

regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, that is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings which are attended by corresponding risks and uncertainties."[158] It does not restrict consideration to other utilities. Similarly, the *Hope* case states: "By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[159] As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q100. ARE DCF RESULTS FOR THE NON-UTILITY GROUP A USEFUL ADJUNCT WHEN APPLYING THE DCF MODEL?

A100. Yes. The results of the non-utility group make estimating the cost of equity using the DCF model more reliable. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities relative to estimates for firms in other industries. Because the Non-Utility Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

Q101. WHAT CRITERIA DO YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A101. My comparable risk proxy group is composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have a Financial

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[158] *Bluefield*, 262 U.S. at 692.
[159] *Hope*, 320 U.S. at 603.

Strength Rating of "A" or greater; (4) have a beta of 0.75 or less; and (5) have investment grade credit ratings from S&P and Moody's.

Q102. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE UTILITY PROXY GROUP?

A102. Table JCP-6 compares the Non-Utility Group with the utility proxy group across four indicators of investment risk:

TABLE JCP-6
COMPARISON OF RISK INDICATORS

	Credit Rating		Value Line		
	S&P	Moody's	Safety Rank	Financial Strength	Beta
Non-Utility Group	A-	A3	1	A+	0.73
Electric Group	BBB+	Baa1	2	A	0.63

Apart from the broad assessment of investment risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Accordingly, my evaluation also included a comparison of three other objective measures of the investment risks associated with common stocks—Value Line's Safety Rank, Financial Strength Rating, and beta. Given that Value Line is perhaps the most widely available source of investment advisory information, its rankings provide useful guidance regarding the risk perceptions of investors.

The Safety Rank is Value Line's primary risk indicator and ranges from "1" (Safest) to "5" (Most Risky). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength.[160] The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Finally, Value Line's beta measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory, and is cited widely in academia and in the investment industry as a guide to investors' risk perceptions.

The companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola and Procter & Gamble, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on par with utilities, with the average dividend yield for the group exceeding 3%.

When considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the utility proxy group to be greater than those of the firms in the Non-Utility Group.

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[160] The Commission has previously considered Value Line's Safety Rank in evaluating relative risks. *Potomac-Appalachian Transmission Highline, LLC*, 133 FERC ¶ 61,152 at P 63 n.90 (2010) (citing cases).

Q103. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A103. As shown on Exhibit No. JCP-208, I calculated the dividend yield component of the DCF model in exactly the same manner described earlier for the utility proxy group. With respect to growth, my application of the DCF model to the Non-Utility Group relied on the same projected IBES EPS growth rates discussed earlier. As shown on Exhibit No. JCP-208, after applying the same tests of low and high-end results discussed earlier in my testimony, my DCF analysis for the Non-Utility Group resulted in an overall ROE range of 6.73% to 13.25%. Meanwhile, the median and midpoint values of 9.69% and 9.99%, respectively, confirm the continued downward bias inherent in the results of the DCF study for the utility proxy group.

Q104. THE COMMISSION PREVIOUSLY DECLINED TO CONSIDER THE IMPLICATIONS OF ROE RESULTS FOR NON-UTILITY FIRMS IN OPINION NO. 531. WHY HAVE YOU INCLUDED THEM IN YOUR EVALUATION IN THIS PROCEEDING?

A104. The Commission has stated that it would not consider the non-utility DCF analysis because this methodology was "not based on electric utilities."[161] With this said, the fact that non-utility companies do not operate in the same industry as electric utilities does not render them irrelevant. As the Commission noted in Opinion No. 531, utilities "must compete for capital with other utilities (*and companies in other sectors*) throughout the nation."[162] More recently, the Briefing Orders concluded that "we must look to how investors analyze and compare their investment opportunities."[163] Investors have many opportunities for their capital and electric utilities must compete for funds with firms outside their own

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[161] Opinion No. 531 at P 146 n.288.
[162] *Id.* at P 96 (emphasis added).
[163] Coakley Briefing Order at P 33; MISO Briefing Order at P 35.

industry. As noted earlier, the investment community has recognized the interrelationship between ROEs for pipelines and electric transmission companies in the allocation of capital, with Wolfe Research noting that lower ROEs for electric transmission could cause investors to divert capital to "other industries generally."[164]

Q105. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A105. Yes, it does.

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[164] Wolfe Research, *FERConomics: Risk to transmission base ROEs in focus*, Utils. & Power (Jun. 11, 2013) at 11.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jersey Central Power & Light Company) Docket No. ER20-___-000

DECLARATION OF ADRIEN M. MCKENZIE, CFA

I, Adrien M. McKenzie, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on October 30, 2019.

/s/ Adrien M. McKenzie
Adrien M. McKenzie

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Adrien M. McKenzie. My business address is 3907 Red River St., Austin, Texas 78751.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a principal in FINCAP, Inc., a firm engaged primarily in financial, economic, and policy consulting in the field of public utility regulation.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have personally sponsored direct and rebuttal testimony in over 130 proceedings filed with the Federal Energy Regulatory Commission ("FERC") and regulatory agencies in Alaska, Arkansas, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Montana, Nebraska, New Mexico, Ohio, Oklahoma, Oregon, South Dakota, Texas, Virginia, Washington, West Virginia, and Wyoming. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair rate of return on equity for regulated electric, gas, and water utility operations. In connection with these assignments, my responsibilities have included critically evaluating the positions of other parties and preparation of rebuttal testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs.

FINCAP was formed in 1979 as an economic and financial consulting firm serving clients in both the regulated and competitive sectors. FINCAP conducts assignments ranging from broad qualitative analyses and policy consulting to technical analyses and research. The firm's experience is in the areas of public utilities, valuation of closely-held businesses, and economic evaluations (e.g., damage and cost/benefit analyses). Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I am a member of the CFA Institute, the CFA Society of Austin. A resume containing the details of my qualifications and experience is attached below.

ADRIEN M. McKENZIE

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Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA®) designation. He has over 30 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

President
FINCAP, Inc.
(June 1984 to June 1987)
(April 1988 to present)

Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.

Manager,
McKenzie Energy Company
(Jan. 1981 to May. 1984)

Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA®) designation in 1990.

Member – CFA Institute.

Bibliography

"A Profile of State Regulatory Commissions," A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

"The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test," with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

"ROE at FERC: Issues and Methods," *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014).

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012).

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. In addition to filings before regulators in over thirty state jurisdictions, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of rate of return on equity ("ROE"), and has broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included developing cost of service and cost allocation studies, the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

SUMMARY OF RESULTS

I. FOUR-MODEL METHODOLOGY

Method	Range		Median		Midpoint
Constant Growth DCF	6.87% -- 14.93%		9.01%		10.90%
ECAPM					
- Historical	8.31% -- 11.53%	10.07%	10.20%	9.92%	10.05%
- Projected	8.71% -- 11.66%	10.33%		10.19%	
	8.51% -- 11.60%				
Expected Earnings	8.20% -- 14.60%		10.75%		11.40%
Risk Premium					
- Historical		9.86%	10.16%	9.86%	10.16%
- Projected		10.46%		10.46%	
Average ROE	**7.86% -- 13.71%**		**10.03%**		**10.63%**

II. ALTERNATIVE BENCHMARK

Method	Range	Median	Midpoint
Non-Utility DCF Model	6.73% -- 13.25%	9.69%	9.99%

UTILITY PROXY GROUP

			(a) S&P Corporate Rating	(b) Moody's Long-term Rating	(c) Value Line Safety Rank	(c) Value Line Financial Strength	(c) Value Line Beta	(c) Market Cap
	Company	**SYM**						
1	Algonquin Pwr & Util	AQN	BBB	NR	n/a	n/a	n/a	$6,770
2	ALLETE	ALE	BBB+	Baa1	2	A	0.65	$4,500
3	Ameren Corp.	AEE	BBB+	Baa1	2	A	0.55	$19,000
4	Avangrid, Inc.	AGR	BBB+	Baa1	2	B++	0.40	$16,000
5	Avista Corp.	AVA	BBB	Baa2	2	A	0.60	$3,000
6	Black Hills Corp.	BKH	BBB+	Baa2	2	A	0.75	$4,800
7	CenterPoint Energy	CNP	BBB+	Baa2	3	B+	0.80	$14,000
8	CMS Energy Corp.	CMS	BBB+	Baa1	2	B++	0.55	$18,000
9	Dominion Energy	D	BBB+	Baa2	2	B++	0.55	$60,000
10	DTE Energy Co.	DTE	BBB+	Baa1	2	B++	0.55	$24,000
11	Entergy Corp.	ETR	BBB+	Baa2	3	B++	0.60	$23,000
12	Exelon Corp.	EXC	BBB+	Baa2	2	B++	0.70	$44,000
13	Hawaiian Elec.	HE	BBB-	Baa2	2	A	0.55	$4,800
14	IDACORP, Inc.	IDA	BBB	Baa1	2	A	0.60	$5,300
15	NorthWestern Corp.	NWE	BBB	Baa2	2	B++	0.60	$3,700
16	OGE Energy Corp.	OGE	BBB+	Baa1	2	A	0.80	$8,700
17	Otter Tail Corp.	OTTR	BBB	Baa2	2	A	0.65	$2,000
18	Portland General Elec.	POR	BBB+	A3	2	B++	0.60	$4,900
19	Pub Sv Enterprise Grp.	PEG	BBB+	Baa1	1	A++	0.65	$29,000
20	Sempra Energy	SRE	BBB+	Baa1	2	A	0.75	$38,000
			BBB+	**Baa1**	**2**	**A**	**0.63**	**$16,674**

(a) Issuer credit rating from www.standardandpoors.com (retrieved Oct. 2, 2019).
(b) Long-term rating from www.moodys.com (retrieved Oct. 2, 2019).
(c) The Value Line Investment Survey (Jul. 26, Aug. 16 & Sep. 13, 2019).

UTILITY PROXY GROUP

	Company	(a) 6-mo. Avg Dividend Yield	(b) IBES Growth	(c) Adjusted Dividend Yield	(d) DCF Result
1	Sempra Energy	2.86%	11.90%	3.03%	14.93%
2	Algonquin Pwr & Util	4.54%	7.83%	4.72%	12.55%
3	Otter Tail Corp.	2.72%	9.00%	2.84%	11.84%
4	Avangrid, Inc.	3.49%	6.40%	3.60%	10.00%
5	CMS Energy Corp.	2.63%	7.14%	2.73%	9.87%
6	Dominion Energy	4.80%	4.59%	4.91%	9.50%
7	CenterPoint Energy	3.92%	5.11%	4.02%	9.13%
8	ALLETE	2.80%	6.00%	2.88%	8.88%
9	Portland General Elec.	2.82%	4.80%	2.89%	7.69%
10	DTE Energy Co.	2.96%	4.45%	3.03%	7.48%
11	Ameren Corp.	2.54%	4.70%	2.60%	7.30%
12	Pub Sv Enterprise Grp.	3.16%	4.05%	3.23%	7.28%
13	Avista Corp.	3.49%	3.40%	3.55%	6.95%
14	OGE Energy Corp.	3.42%	3.40%	3.47%	6.87%
15	NorthWestern Corp.	3.23%	3.24%	3.28%	6.52%
16	Hawaiian Elec.	2.98%	3.40%	3.03%	6.43%
17	Black Hills Corp.	2.65%	2.96%	2.69%	5.65%
18	IDACORP, Inc.	2.44%	2.50%	2.47%	4.97%
19	Entergy Corp.	3.54%	-1.50%	3.52%	2.02%
20	Exelon Corp.	3.01%	-2.24%	2.98%	0.74%
	Lower End (e)				**6.87%**
	Upper End (e)				**14.93%**
	Median (e)				**9.01%**
	Midpoint				**10.90%**
	Low-End Test				**6.66%**
	High-End Test				**15.98%**

(a) Six-month average dividend yield for Apr. - Sep. 2019.
(b) www.finance.yahoo.com (retreived Oct. 2, 2019).
(c) Six-month average dividend yield x [1+ (Growth Rate / 2)].
(d) (b) + (c)
(e) Excludes highlighted values.

HISTORICAL BOND YIELDS

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	ECAPM
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP*** [1]	**Beta**	**Weight**	***RP*** [2]	**RP**	**K_e**	**Cap**	**Adjustment**	**Result**
1	Algonquin Pwr & Util	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	n/a	75%	n/a	n/a	n/a	$6,770	0.82%	n/a
2	OGE Energy Corp.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.80	75%	5.76%	8.16%	10.69%	$8,700	0.84%	11.53%
3	CenterPoint Energy	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.80	75%	5.76%	8.16%	10.69%	$14,000	0.50%	11.19%
4	Black Hills Corp.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.75	75%	5.40%	7.80%	10.33%	$4,800	0.82%	11.15%
5	Otter Tail Corp.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.65	75%	4.68%	7.08%	9.61%	$2,000	1.54%	11.15%
6	ALLETE	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.65	75%	4.68%	7.08%	9.61%	$4,500	1.26%	10.87%
7	Avista Corp.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.60	75%	4.32%	6.72%	9.25%	$3,000	1.26%	10.51%
8	NorthWestern Corp.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.60	75%	4.32%	6.72%	9.25%	$3,700	1.26%	10.51%
9	Pub Sv Enterprise Grp.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.65	75%	4.68%	7.08%	9.61%	$29,000	0.50%	10.11%
10	Portland General Elec.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.60	75%	4.32%	6.72%	9.25%	$4,900	0.82%	10.07%
11	IDACORP, Inc.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.60	75%	4.32%	6.72%	9.25%	$5,300	0.82%	10.07%
12	Sempra Energy	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.75	75%	5.40%	7.80%	10.33%	$38,000	-0.29%	10.04%
13	Entergy Corp.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.60	75%	4.32%	6.72%	9.25%	$23,000	0.50%	9.75%
14	Hawaiian Elec.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.55	75%	3.96%	6.36%	8.89%	$4,800	0.82%	9.71%
15	Exelon Corp.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.70	75%	5.04%	7.44%	9.97%	$44,000	-0.29%	9.68%
16	Ameren Corp.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.55	75%	3.96%	6.36%	8.89%	$19,000	0.50%	9.39%
17	CMS Energy Corp.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.55	75%	3.96%	6.36%	8.89%	$18,000	0.50%	9.39%
18	DTE Energy Co.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.55	75%	3.96%	6.36%	8.89%	$24,000	0.50%	9.39%
19	Dominion Energy	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.55	75%	3.96%	6.36%	8.89%	$60,000	-0.29%	8.60%
20	Avangrid, Inc.	2.41%	9.72%	12.13%	2.53%	9.60%	25%	2.40%	0.40	75%	2.88%	5.28%	7.81%	$16,000	0.50%	8.31%
	Lower End (h)															**8.31%**
	Upper End (h)															**11.53%**
	Median (h)															**10.07%**
	Midpoint															**9.92%**
	Low-End Test															**6.66%**
	High-End Test															**15.98%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Sep. 26, 2019).
(b) Weighted average earnings growth rate from IBES and The Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Sep. 27, 2019) and www.valueline.com (retrieved Sep. 26, 2019).
(c) Six-month average yield on 30-year Treasury bonds for Apr. - Sep. 2019 from https://fred.stlouisfed.org/.
(d) Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 190.
(e) The Value Line Investment Survey (Jul. 26, Aug. 16 & Sep. 13, 2019).
(f) The Value Line Investment Survey (Jul. 26, Aug. 16 & Sep. 13, 2019).
(g) Duff & Phelps, 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(h) Excludes highlighted values.

PROJECTED BOND YIELDS

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				**Market**										
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**	**Unadjusted RP**		**Beta Adjusted RP**			**Total**	**Unadjusted**	**Market**	**Size**	**ECAPM**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP*** [1]	**Beta**	**Weight**	***RP*** [2]	**RP**	**K_e**	**Cap**	**Adjustment**	**Result**
1	Algonquin Pwr & Util	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	n/a	75%	n/a	n/a	n/a	$6,770	0.82%	n/a
2	OGE Energy Corp.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.80	75%	5.24%	7.42%	10.82%	$8,700	0.84%	11.66%
3	Otter Tail Corp.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.65	75%	4.26%	6.44%	9.84%	$2,000	1.54%	11.37%
4	CenterPoint Energy	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.80	75%	5.24%	7.42%	10.82%	$14,000	0.50%	11.32%
5	Black Hills Corp.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.75	75%	4.91%	7.09%	10.49%	$4,800	0.82%	11.31%
6	ALLETE	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.65	75%	4.26%	6.44%	9.84%	$4,500	1.26%	11.09%
7	Avista Corp.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.60	75%	3.93%	6.11%	9.51%	$3,000	1.26%	10.77%
8	NorthWestern Corp.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.60	75%	3.93%	6.11%	9.51%	$3,700	1.26%	10.77%
9	Pub Sv Enterprise Grp.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.65	75%	4.26%	6.44%	9.84%	$29,000	0.50%	10.34%
10	Portland General Elec.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.60	75%	3.93%	6.11%	9.51%	$4,900	0.82%	10.33%
11	IDACORP, Inc.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.60	75%	3.93%	6.11%	9.51%	$5,300	0.82%	10.33%
12	Sempra Energy	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.75	75%	4.91%	7.09%	10.49%	$38,000	-0.29%	10.21%
13	Entergy Corp.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.60	75%	3.93%	6.11%	9.51%	$23,000	0.50%	10.01%
14	Hawaiian Elec.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.55	75%	3.60%	5.78%	9.18%	$4,800	0.82%	10.01%
15	Exelon Corp.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.70	75%	4.58%	6.77%	10.17%	$44,000	-0.29%	9.88%
16	Ameren Corp.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.55	75%	3.60%	5.78%	9.18%	$19,000	0.50%	9.69%
17	CMS Energy Corp.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.55	75%	3.60%	5.78%	9.18%	$18,000	0.50%	9.69%
18	DTE Energy Co.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.55	75%	3.60%	5.78%	9.18%	$24,000	0.50%	9.69%
19	Dominion Energy	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.55	75%	3.60%	5.78%	9.18%	$60,000	-0.29%	8.90%
20	Avangrid, Inc.	2.41%	9.72%	12.13%	3.40%	8.73%	25%	2.18%	0.40	75%	2.62%	4.80%	8.20%	$16,000	0.50%	8.71%
	Lower End (h)															**8.71%**
	Upper End (h)															**11.66%**
	Median (h)															**10.33%**
	Midpoint															**10.19%**
	Low-End Test															**6.66%**
	High-End Test															**15.98%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Sep. 26, 2019).
(b) Weighted average earnings growth rate from IBES and The Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Sep. 27, 2019) and www.valueline.com (retrieved Sep. 26, 2019).
(c) Average yield on 30-year Treasury bonds for 2020-24 based on data from Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 30, 2019), IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019), and Energy Information Administration, Annual Energy Outlook 2019 (Jan. 24, 2019).
(d) Roger A. Morin, "New Regulatory Finance," Public Utilities Reports, Inc. (2006) at 190.
(e) The Value Line Investment Survey (Jul. 26, Aug. 16 & Sep. 13, 2019).
(f) The Value Line Investment Survey (Jul. 26, Aug. 16 & Sep. 13, 2019).
(g) Duff & Phelps, 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(h) Excludes highlighted values.

EXPECTED EARNINGS APPROACH

UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Algonquin Pwr & Util	n/a	n/a	n/a
2	CMS Energy Corp.	14.00%	1.0429	14.60%
3	Dominion Energy	13.00%	1.0538	13.70%
4	Sempra Energy	12.00%	1.0500	12.60%
5	OGE Energy Corp.	11.50%	1.0163	11.69%
6	Entergy Corp.	11.00%	1.0326	11.36%
7	Otter Tail Corp.	11.00%	1.0280	11.31%
8	Pub Sv Enterprise Grp.	11.00%	1.0239	11.26%
9	DTE Energy Co.	10.50%	1.0361	10.88%
10	Ameren Corp.	10.50%	1.0329	10.85%
11	CenterPoint Energy	10.00%	1.0648	10.65%
12	Hawaiian Elec.	10.00%	1.0255	10.26%
13	Black Hills Corp.	9.50%	1.0267	9.75%
14	IDACORP, Inc.	9.50%	1.0184	9.67%
15	ALLETE	9.50%	1.0158	9.65%
16	Exelon Corp.	9.00%	1.0267	9.24%
17	NorthWestern Corp.	9.00%	1.0163	9.15%
18	Portland General Elec.	9.00%	1.0163	9.15%
19	Avista Corp.	8.00%	1.0250	8.20%
20	Avangrid, Inc.	6.00%	1.0080	6.05%
	Lower End (d)			**8.20%**
	Upper End (d)			**14.60%**
	Median (d)			**10.75%**
	Midpoint			**11.40%**
	Low-End Test			**6.66%**
	High-End Test			**15.98%**

(a) The Value Line Investment Survey (Jul. 26, Aug. 16 & Sep. 13, 2019).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) (a) x (b).
(d) Excludes highlighted values.

RISK PREMIUM METHOD

HISTORICAL BOND YIELDS

Current Equity Risk Premium

(a) Average Yield Over Study Period	5.53%
(b) Baa Utility Bond Yield	4.13%
Change in Bond Yield	-1.40%
(c) Risk Premium/Interest Rate Relationship	-0.5990
Adjustment to Average Risk Premium	0.84%
(a) Average Risk Premium over Study Period	4.89%
Adjusted Risk Premium	**5.73%**

Implied Cost of Equity

(b) Baa Utility Bond Yield	4.13%
Adjusted Equity Risk Premium	5.73%
Risk Premium Cost of Equity	**9.86%**

(a) See Exhibit No. JCP-207, p. 3.
(b) Six-month average yield for Apr. - Sep. 2019 based on data from Moody's Investors Service, www.moodys.credittrends.com.
(c) See Exhibit No. JCP-207, p. 7.

PROJECTED BOND YIELDS

Current Equity Risk Premium	
(a) Average Yield Over Study Period	5.53%
(b) Baa Utility Bond Yield 2020-24	5.63%
Change in Bond Yield	0.10%
(c) Risk Premium/Interest Rate Relationship	-0.5990
Adjustment to Average Risk Premium	-0.06%
(a) Average Risk Premium over Study Period	4.89%
Adjusted Risk Premium	**4.83%**

Implied Cost of Equity	
(b) Baa Utility Bond Yield 2020-24	5.63%
Adjusted Equity Risk Premium	4.83%
Risk Premium Cost of Equity	**10.46%**

(a) See Exhibit No. JCP-207, p. 3.
(b) Based on data from IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019); Energy Information Administration, Annual Energy Outlook 2019 (Jan. 24, 2019); & Moody's Investors Service at www.credittrends.com.
(c) See Exhibit No. JCP-207, p. 7.

IMPLIED RISK PREMIUM

Year	(a) Average Base ROE	(b) Baa Utility Bond Yield	Risk Premium
2006	11.01%	6.32%	4.69%
2007	10.96%	6.33%	4.63%
2008	10.83%	7.25%	3.58%
2009	10.85%	7.06%	3.79%
2010	10.59%	5.98%	4.62%
2011	10.68%	5.57%	5.12%
2012	10.82%	4.86%	5.97%
2013	10.20%	4.98%	5.22%
2014	10.04%	4.80%	5.24%
2015	10.09%	5.03%	5.06%
2016	9.87%	4.68%	5.19%
2017	9.77%	4.38%	5.39%
2018	9.74%	4.67%	5.07%
		5.53%	4.89%

(a) Exhibit No. JCP-207, pp. 4-6.
(b) Moody's Investors Service, www.credittrends.com.

ALLOWED ROE

Date	Docket No.	Utility	Base ROE
Apr-06	ER05-515	Baltimore Gas & Elec.	10.80%
Apr-06	ER05-515	Baltimore Gas & Elec.	11.30%
Oct-06	ER04-157	Bangor Hydro-Elec. Co.	11.14%
Nov-06	ER05-925	Westar Energy Inc.	10.80%
May-07	ER07-284	San Diego Gas & Elec.	11.35%
Aug-07	ER06-787	Idaho Power Co.	10.70%
Sep-07	ER06-1320	Wisconsin Elec. Pwr. Co.	11.00%
Nov-07	ER08-10	Pepco Holdings, Inc.	10.80%
Jan-08	ER07-583	Commonwealth Edison Co.	11.00%
Feb-08	ER08-374	Atlantic Path 15	10.65%
Mar-08	ER08-396	Westar Energy Inc.	10.80%
Mar-08	ER08-413	Startrans IO, LLC	10.65%
Apr-08	EL05-19	Southwestern Public Service	9.33%
Apr-08	ER08-92	Virginia Elec. & Power Co.	10.90%
May-08	EL06-109	Duquesne Light Co.	10.90%
Jun-08	ER07-549	NSTAR Elec. Co.	10.90%
Jul-08	ER08-375	So. Cal Edison (a)	9.54%
Jul-08	ER07-562	Trans-Allegheny	11.20%
Jul-08	ER07-1142	Arizona Public Service Co.	10.75%
Aug-08	ER08-1207	Virginia Elec. & Power Co.	10.90%
Aug-08	ER08-686	Pepco Holdings, Inc.	11.30%
Sep-08	ER08-1233	Public Service Elec. & Gas	11.18%
Oct-08	ER08-1423	Pepco Holdings, Inc.	10.80%
Oct-08	EL08-74	Central Maine Power Co.	11.14%
Oct-08	ER08-1402	Duquesne Light Co.	10.90%
Nov-08	ER08-1548	Northeast Utils Service Co.	11.14%
Nov-08	EL08-77	Central Maine Power Co.	11.14%
Dec-08	ER09-14	NSTAR Elec. Co.	11.14%
Dec-08	ER09-35/36	Tallgrass / Prairie Wind	10.80%
Dec-08	ER07-694	New England Pwr. Co.	11.14%
Feb-09	ER08-1584	Black Hills Power Co.	10.80%
Mar-09	ER09-75	Pioneer Transmission	10.54%
Mar-09	ER09-548	ITC Great Plains	10.66%
Mar-09	ER09-249	Public Service Elec. & Gas	11.18%
Apr-09	ER09-681	Green Power Express	10.78%
May-09	ER09-745	Baltimore Gas & Elec.	11.30%
Jun-09	ER08-552	Niagara Mohawk Pwr. Co.	11.00%
Jun-09	ER07-1069	AEP - SPP Zone	10.70%
Jun-09	ER08-281	Oklahoma Gas & Elec.	10.60%
Aug-09	ER08-1457	PPL Elec. Utilities Corp.	11.10%
Aug-09	ER08-1457	PPL Elec. Utilities Corp.	11.14%
Aug-09	ER08-1457	PPL Elec. Utilities Corp.	11.18%
Aug-09	ER09-187	So. Cal Edison (b)	10.04%
Aug-09	ER07-1344	Westar Energy Inc.	10.80%
Nov-09	ER08-1588	Kentucky Utilities Co.	11.00%
Nov-09	ER09-1762	Westar Energy Inc.	10.80%
Dec-09	ER08-313	Southwestern Public Service Co.	10.77%

ALLOWED ROE

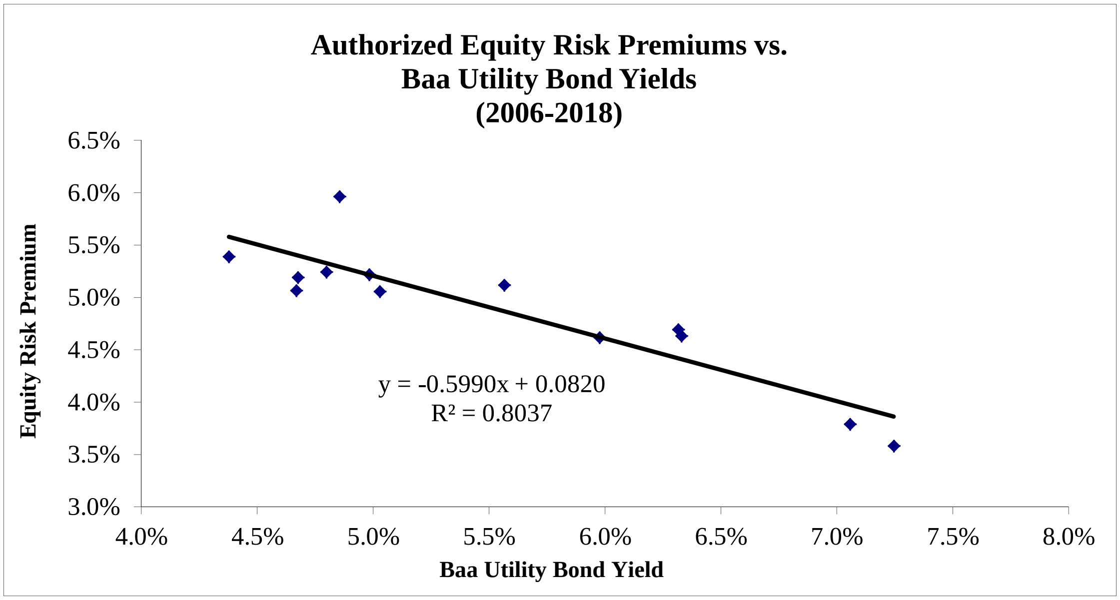
Date	Docket No.	Utility	ROE
Jan-10	ER09-628	National Grid Generation LLC	10.75%
Sep-10	ER10-160	So. Cal Edison (c)	10.33%
Oct-10	ER08-1329	AEP - PJM Zone	10.99%
Dec-10	ER10-230	Kansas City Power & Light Co.	10.60%
Dec-10	ER11-1952	So. Cal Edison	10.30%
Feb-11	ER11-2377	Northern Pass Transmission	10.40%
Apr-11	ER10-355	AEP Transcos - PJM	10.99%
Apr-11	ER10-355	AEP Transcos - SPP	10.70%
May-11	EL10-80	Ameren	12.38%
May-11	EL11-13	Atlantic Grid Operations	10.09%
Jun-11	ER11-3352	PJM & PSE&G	11.18%
Aug-11	ER10-992	Northern States Power Co.	10.20%
Oct-11	ER10-1377	Northern States Power Co. (MN)	10.40%
Oct-11	ER11-2895	Duke Energy Carolinas	10.20%
Oct-11	ER11-4069	RITELine	9.93%
Oct-11	ER10-516	South Carolina Elec. & Gas	10.55%
Dec-11	ER12-296	PJM & PSE&G	11.18%
Feb-12	ER08-386	PATH	10.40%
Jun-12	ER11-2853	Public Service Co. of Colorado	10.10%
Jun-12	ER11-2853	Public Service Co. of Colorado	10.40%
Jun-12	ER12-1593	DATC Midwest Holdings	12.38%
Feb-13	ER12-1378	Cleco Power LLC	10.50%
May-13	ER12-778	Puget Sound Energy	9.80%
May-13	ER12-778	Puget Sound Energy - PSANI	10.30%
May-13	ER11-3643	PacifiCorp	9.80%
May-13	ER11-2560	Entergy Arkansas	10.20%
May-13	ER12-2554	Transource Missouri	9.80%
Jun-13	ER12-2681	ITC Holdings	12.38%
Aug-13	ER12-1650	Maine Public Service Co.	9.75%
Nov-13	ER11-3697	So. Cal Edison	9.30%
May-14	ER13-941	San Diego Gas & Electric	9.55%
May-14	ER14-1608	Public Service Electric & Gas	11.18%
Oct-14	ER12-1589	Public Service Co. of Colorado	9.72%
Oct-14	EL13-86	Public Service Co. of Colorado	9.72%
Apr-15	ER12-91	Duke Energy Ohio	10.88%
May-15	EL12-101	Niagara Mohawk Power Corp.	9.80%
Jun-15	ER14-1661	MidAmerican Central Calif. Transco	9.80%
Sep-15	ER13-2428	Kentucky Utilities Co.	10.25%
Oct-15	ER14-192	Southwestern Public Service Co.	10.00%
Oct-15	ER15-303	American Transmission Systems, Inc.	9.88%
Nov-15	EL12-39	Duke Energy Florida	10.00%

ALLOWED ROE

Date	Docket No.	Utility	ROE
Feb-16	EL15-27	Baltimore G&E / Pepco Holdings, Inc.	10.00%
Mar-16	ER15-572	New York Transco LLC	9.50%
Mar-16	ER13-685	Public Service Company of New Mexico	10.00%
Mar-16	EL14-93	Westar Energy	9.80%
Apr-16	ER15-1809	ATX Southwest, LLC	9.90%
Jul-16	ER15-958	Transource Kansas, LLC	9.80%
Jul-16	ER14-2751	Xcel Energy Southwest Trans. Co. (Gen)	10.20%
Jul-16	ER14-2751	Xcel Energy Southwest Trans. Co. (Zn 11)	10.00%
Apr-16	ER15-2237	Kanstar Transmission, LLC	9.80%
Oct-16	ER15-2069	NorthWestern Corp.	9.65%
Oct-16	ER15-2239	NextEra Energy Transmission West	9.70%
Oct-16	ER15-1682	TransCanyon DCR, LLC	9.80%
Nov-16	ER16-453	Northeast Transmission Development	9.85%
Nov-16	EL16-30	Duke Energy Carolinas	10.00%
Dec-16	ER15-2114	Transource West Virginia, LLC	10.00%
Jan-17	ER09-1256	Potomac-Appalachian Trans. Highline	(d)
Nov-17	ER16-2717	NextEra Transmission Midwest, LLC	10.32%
Nov-17	ER15-572	New York Transco, LLC	9.65%
Nov-17	ER17-856	Rockland Electric Co.	9.50%
Nov-17	ER15-1429	Emera Maine	9.60%
Jan-18	ER17-419	Transource Pennsylvania/Maryland, LLC	9.90%
Mar-18	ER16-2720	NextEra Energy Trans. Southwest LLC	9.80%
Apr-18	ER16-2716	NextEra Energy Trans. MidAtlantic, LLC	9.60%
May-18	ER17-211	Mid-Atlantic Interstate Transmission	9.80%
Jun-18	ER17-706	GridLiance West Transco LLC	9.60%
Aug-18	ER16-2719	NextEra Energy Trans. New York LLC	9.65%
Nov-18	ER17-135	DesertLink, LLC	9.80%

(a) Order issued April 15, 2010, with ROE applied for March 1, 2008 through December 31, 2008.
(b) Order issued April 19, 2012, with ROE applied for January 1, 2009 through May 31, 2010.
(c) Order issued April 19, 2012, with ROE applied for June 1, 2010 through December 31, 2010.
(d) ROE finding does not apply to operational risks of an ongoing utility.

REGRESSION RESULTS



Regression Statistics	
Multiple R	0.89651
R Square	0.80373
Adjusted R Square	0.78589
Standard Error	0.00297
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.000397	0.000397226	45.0456819	3.32394E-05
Residual	11	0.000097	8.81829E-06		
Total	12	0.000494			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.08202	0.00500	16.39309965	4.45967E-09	0.07101	0.09303	0.07101	0.09303
X Variable 1	-0.59900	0.08925	-6.711607997	3.32394E-05	-0.79544	-0.40257	-0.79544	-0.40257

CONSTANT GROWTH DCF MODEL

NON-UTILITY GROUP

	Company	Industry Group	(a) 6-Mo. Div. Yield	(b) Adjusted Yield	(c) IBES Growth	(d) DCF Result
1	AT&T Inc.	Telecom. Services	6.17%	6.23%	2.20%	8.43%
2	Church & Dwight	Household Products	1.22%	1.27%	8.16%	9.43%
3	Coca-Cola	Beverage	3.13%	3.21%	5.20%	8.41%
4	Federal Rlty. Inv. Trust	REIT	3.13%	3.24%	6.70%	9.94%
5	Gen'l Mills	Food Processing	3.74%	3.86%	6.53%	10.39%
6	Kellogg	Food Processing	3.86%	3.87%	0.77%	4.64%
7	Kimberly-Clark	Household Products	3.10%	3.17%	4.79%	7.96%
8	Lilly (Eli)	Drug	2.26%	2.37%	9.80%	12.17%
9	McCormick & Co.	Food Processing	1.46%	1.52%	9.30%	10.82%
10	PepsiCo, Inc.	Beverage	2.92%	2.98%	3.75%	6.73%
11	Procter & Gamble	Household Products	2.67%	2.77%	7.30%	10.07%
12	Public Storage	REIT	3.35%	3.64%	17.00%	20.64%
13	Smucker (J.M.)	Food Processing	2.99%	3.05%	4.33%	7.38%
14	Sysco Corp.	Wholesale Food	2.18%	2.30%	10.95%	13.25%
15	Verizon Communic.	Telecom. Services	4.21%	4.27%	2.86%	7.13%
16	Walmart Inc.	Retail Store	1.97%	2.01%	3.69%	5.70%
17	Waste Management	Environmental	1.83%	1.91%	8.55%	10.46%
	Lower End (g)					**6.73%**
	Upper End (g)					**13.25%**
	Median (g)					**9.69%**
	Midpoint					**9.99%**
	Low-End Test					**6.66%**
	High-End Test					**15.98%**

(a) Six-month average dividend yield for Apr. - Sep. 2019.
(b) Six-month average yield x [1 + 0.5 x (c)].
(c) www.finance.yahoo.com (retrieved Sep. 3, 2019).
(d) Sum of adjusted yield and growth rate.
(e) The Value Line Investment Survey (Jun. 14, Jun. 21, Jul. 5, Jul. 19, & Aug. 23, 2019).
(f) www.zacks.com (retrieved Sep. 9, 2019).
(g) Excludes highlighted values.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Jersey Central Power & Light Company) Docket No. ER20-___-000

**DIRECT TESTIMONY
OF
JOHN J. SPANOS**

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING?

A. I have been associated with the firm since college graduation in June 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am President.

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. I have over 33 years of depreciation experience, which includes giving expert testimony in over 300 cases before 400 regulatory commissions, including the Federal Energy Regulatory Commission ("FERC"). These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. 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 TESTIMONY IN THIS PROCEEDING?

A. I am presenting a report describing the results of the depreciation study that I performed for Jersey Central Power and Light Company ("JCP&L" or the "Company"), attached hereto as Exhibit JCP-302. I understand that the Company intends to use the results of this study for the purposes of its cost accounting. In addition, I understand that the Company intends to use the results of this study to establish the depreciation rates used to set its FERC-regulated transmission charges.

II. 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 operation, 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.[1]

Q. DID YOU PREPARE A REPORT DESCRIBING THE RESULTS OF YOUR DEPRECIATION STUDY?

A. Yes. I prepared the report entitled: "2018 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2018," attached as Exhibit JCP-302. This report sets forth the results of my depreciation study for JCP&L.

Q. IN PREPARING THE DEPRECIATION STUDY, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION VALUATION?

A. Yes.

Q. ARE THE METHODS AND PROCEDURES OF THIS DEPRECIATION STUDY CONSISTENT WITH INDUSTRY PRACTICES?

A. Yes. The methods and procedures of this study are the same as those utilized by most utilities across the United States. Depreciation rates are determined based on the average service life procedure and the remaining life method.

Q. HAS JCP&L CHANGED SINCE THE LAST RATE CASE ITS TREATMENT OF COST OF REMOVAL IN A WAY THAT AFFECTS YOUR STUDY?

A. Yes, it did, but for general plant assets only (not for transmission assets).

Q. PLEASE EXPLAIN.

[1] Depreciation definition as utilized by the FERC Code of Federal Regulations Title 18, Subchapter C, Part 101, page 318 and the National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices, page 13.

A. In accordance with the well-established accrual methodology and the full definition of depreciation, JCP&L changed, for general plant assets only, its practice of recording cost of removal and gross salvage and the accrual of these costs through the Accumulated Provision of Depreciation Account (Account 108). More specifically, in accordance with well-established practices across the United States and supported by the FERC, JCP&L now records cost of removal and gross salvage as incurred through the Accumulated Provision for Depreciation Account. Additionally, the recovery of the full service value of each asset includes the net salvage percentage in the annual accrual or annual depreciation expense. This process insures full recovery of the service value of the asset equally over the life of the asset. And as a result of this change, general plant depreciation is handled consistently with that of all other assets.

Q. WHAT DID JCP&L DO PREVIOUSLY?

A. Previously, the general plant assets had cost of removal and gross salvage expensed and not included in the depreciation rate.

Q. IS THIS CURRENT APPROACH NOW USED BY JCP&L CONSISTENT WITH INDUSTRY PRACTICE?

A. Yes. The approach is a common approach across the country.

Q. PLEASE DESCRIBE THE CONTENTS OF YOUR REPORT.

A. The Depreciation Study is presented in nine parts. Part I, Introduction, presents the scope and basis for the depreciation study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining service life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Parts VII, VIII and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account.

The table on pages VI-4 and VI-5 presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2018, the book depreciation reserve and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page VII-2 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-2 presents the results of the salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2018.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.

A. I used the straight line remaining life method of depreciation, with the average service life procedure which is the most commonly used depreciation 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 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 annual depreciation is based on a method of depreciation accounting that seeks 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, 391.20, 391.25, 393.00, 394.00, 395.00, 397.00, and 398.00, I used the straight line remaining method of amortization. The annual amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

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 and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historical data from records related to JCP&L's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplemental information from the Company 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 and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions generally during the period 1947 through 2018. The transactions included additions, retirements, transfers, sales and the related balances.

Q. WHAT METHOD DID YOU USE TO ANALYZE THESE SERVICE LIFE DATA?

A. I used the retirement rate method. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the depreciation study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE THE COMPANY'S SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data 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 survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa type curves were developed at the Iowa State College 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 type curves and truncated Iowa type 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.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa type curve system to which the property group belongs, and the relative height of the mode. For example, the Iowa 60-R2 curve indicates an average service life of sixty years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 2, for the mode (possible modes for R-type curves range from 1 to 5).

Q. DID YOU PHYSICALLY OBSERVE JCP&L'S PLANT AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDY?

A. Yes. I made field reviews of JCP&L's property during September 2019 to observe representative portions of plant. I have also made field visits during prior studies since 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. This knowledge as well as information from other discussions with management was incorporated in the interpretation and extrapolation of the statistical analyses.

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 $50,000 circuit breaker will include not only the $50,000 of original cost, but also, on average, $11,000 to remove the circuit breaker at the end of its life and $1,000 in salvage value. In this example, the salvage component is negative $10,000 (1,000-11,000) and the net salvage percent is negative 20% (($1,000 – 11,000)/$50,000).

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. The net salvage percentages estimated in the Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided to me by the Company's personnel, general knowledge and experience of the industry practices; and trends in the industry in general. The statistical net salvage analyses incorporate the Company's actual historical data for the period 2005 through 2018, and consider the cost of removal and gross salvage ratios to the associated retirements during the 14-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line remaining life method, and using remaining lives weighted consistent with the average service life procedure.

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 and future net salvage, in equal amounts to each year of remaining service life.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING.

A. Amortization accounting is used for accounts with a large number of units, but small asset values. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, retirements are recorded to properly reflect plant in service when a vintage is fully amortized rather than as the units are removed from service. That is, 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 during which the asset will render service. 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 books, but not necessarily removed from service. In contrast, assets that are taken out of service before 20 years remain on the books until the amortization period for that vintage has expired.

Q. FOR WHICH PLANT ACCOUNTS IS AMORTIZATION ACCOUNTING BEING IMPLEMENTED?

A. Amortization accounting is only appropriate for certain General Plant accounts. These accounts are 391.10, 391.15, 391.20, 391.25, 393.00, 394.00, 395.00, 397.00 and 398.00, which represent slightly more than one percent of depreciable plant.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR DEPRECIATION STUDY.

A. I will use Account 355, Poles and Fixtures, as an example because it is one of the largest depreciable mass accounts and represents approximately 20 percent of depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1931 through 2018. This data was analyzed in periods that best represent the overall service life of this property. The life table for the 1931–2018 experience band is presented on pages VII-31 through VII-36 of the report. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-31 shows $9,792,743 retired at age 0.5 with $332,030,153 exposed to retirement. Consequently, the retirement ratio is 0.0295 and the surviving ratio is 0.9705. The percent surviving age at age 0.5 of 0.9889 percent is multiplied by the survivor rate of 97.05 to derive the percent surviving at age 1.5 of 95.98 percent. The process continues for the remaining age intervals for which plant was exposed to retirement during the period 1931–2018. This life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 60-R2 on page VII-30.

The net salvage analyses for Account 355, Poles and Fixtures, is presented on page VIII-6 of the Depreciation Study. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 2005 through 2018. This 14-year period experienced $6,328,121 ($152,559 - $6,480,681) in negative net salvage for $30,487,052 plant retired. The result is negative net salvage of 21 percent ($6,328,121/$30,487,052). Based on the overall 21 percent negative net salvage, and considering the industry range of negative 25 to negative

75 percent along with Company expectations, it was determined that negative 20 percent is the most appropriate estimate.

My calculation of the annual depreciation related to the original cost at December 31, 2018, of utility plant is presented on pages IX-13 through IX-14. The calculation is based on the 60-R2 survivor curve, 20 percent negative net salvage, 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 the table on page VI-4.

Q. ARE THERE OTHER RECOVERY AMOUNTS THAT WERE INCLUDED IN THE STUDY?

A. Yes. The recovery amount is the unrecovered reserve amortization established for certain general plant accounts. In order to achieve a more stable accrual for general plant accounts in the future, I have recommended a five-year amortization to adjust unrecovered reserve. This approach will achieve consistent amortization rates for existing assets as well as future assets. The reserve for each of these accounts is segregated into two components. The first component is the amount required to achieve the proper rate for the amortization period. The remaining amount, which could be negative, is amortized over 5 years separately from the assets.

Q. DO YOU HAVE A RECOMMENDATION AS TO WHAT DEPRECIATION RATES THE COMPANY SHOULD USE FOR ITS COST ACCOUNTING AND SETTING FERC-REGULATED TRANSMISSION RATES?

A. Yes. I recommend that the Company use for its cost accounting and set its transmission charges based on the depreciation rates in Column 8 of the table on pages VI-4 and VI-5 of my report.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Exhibit No. JCP-300

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jersey Central Power & Light Company) Docket No. ER20-___-000

DECLARATION OF JOHN J. SPANOS

I, John J. Spanos, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on October 30, 2019.

/s/ John J. Spanos
John J. Spanos

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.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
134.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
135.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
136.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
137.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
138.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
139.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
140.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
141.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
142.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
143.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
144.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
145.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
146.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
147.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
148.	2012	FERC	ER12-2681-000	ITC Holdings	Depreciation
149.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
150.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
151.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
152.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
153.	2012	TX PUC		Aqua Texas	Depreciation
153.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
155.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
156.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
157.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
158.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
159.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
160.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
161.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
162.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
163.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
164.	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
165.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
166.	2013	FERC	ER13-2428-000	Kentucky Utilities	Depreciation
167.	2013	FERC	ER13-1187-000	MidAmerican Energy Company	Depreciation
168.	2013	FERC	ER13-2410-000	PPL Utilities	Depreciation
169.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
170.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
171.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
172.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
173.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
174.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
175.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
176.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
177.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
178.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
179.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
180.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
181.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
182.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
183.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
184.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
185.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
186.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
188.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
189.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
190.	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
191.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
192	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
193.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
194.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
195.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
196.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
197.	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
198.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
199.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
200.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
201.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
202.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
203.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
204.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
205.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
206.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
207.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
208.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
209.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
210.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
211.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
212.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
213.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
214.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
215.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
216.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
217.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
218.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
219.	2016	WI PSC		Wisconsin Public Service Commission	Depreciation
220.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
221.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
222.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
223.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
224.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
225.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
226.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
227.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
228.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
229.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
230.	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
231.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
232.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
233.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
234.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
235.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
236.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
237.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
238.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
239.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
240.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
241.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
242.	2016	IN URC		Indianapolis Power & Light	Depreciation
243.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
244.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
245.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
246.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
247.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
248.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
249.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
250.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
251.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
252.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
253.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
254.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
255.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
256.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
257.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
258.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
259.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
260.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
261.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
262.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
263.	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
264.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
265.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
266.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
267.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
268.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
269.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
270.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
271.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
272.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
273.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
274.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
275.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
276.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
277.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
278.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
279.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
280.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
281.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
282.	2018	FERC	Docket No. ER18-1228-000	Duke Energy Progress	Depreciation
283.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
284.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
285.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
286.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
287.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
288.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
290.	2018	FERC	ER18-2231-000	Duke Energy Carolinas, LLC	Depreciation
291.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
292.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
293.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
294.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
295.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
296.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
297.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
298.	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
299.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
300.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
301.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
302.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
303.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
304.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
305.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
306.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
307.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
308.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
309.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
310.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
311.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
312.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
313.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
314.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
315.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
316.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
317.	2019	WA UTC	Docket UE-19 / UG-19	Puget Sound Energy	Depreciation
318.	2019	PA PUC	Docket No. R-2019-	City of Lancaster	Depreciation
319.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
320.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
321.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
322.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation

JERSEY CENTRAL POWER & LIGHT COMPANY

MORRISTOWN, NEW JERSEY

2018 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC TRANSMISSION PLANT
AS OF DECEMBER 31, 2018

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***

JERSEY CENTRAL POWER & LIGHT COMPANY

Morristown, New Jersey

2018 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC TRANSMISSION PLANT AS OF DECEMBER 31, 2018

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Harrisburg, Pennsylvania

Gannett Fleming

Excellence Delivered **As Promised**

October 25, 2019

FirstEnergy Service Company
76 South Main Street
Akron, OH 44308

Attention: Morgan E. Parke
Associate General Counsel

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric transmission plant of Jersey Central Power & Light Company as of December 31, 2018. 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.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John J. Spanos

JOHN J. SPANOS
President

JJS:mle

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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 transmission and general plant as of December 31, 2018. 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, and forecasted net salvage characteristics for each depreciable group of assets.

JCP&L's accounting policy has not changed since the last depreciation study related to the transmission plant. There have been some changes in life parameters and net salvage percentages which have caused the proposed remaining lives for some accounts to fluctuate from those previously approved.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric transmission plant and the allocated portion of intangible and general plant in service as of December 31, 2018 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 $36.2 million when applied to the related depreciable electric transmission plant balances as of December 31, 2018.

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 transmission and general plant in service as of December 31, 2018. 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 transmission and general plant in service as of December 31, 2018.

The service life and net salvage 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 analyses of historical plant retirement data recorded through 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 study. 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, Part VIII, Net Salvage Statistics sets forth the statistical indications of net salvage percents, and Part IX, Detailed Depreciation Calculations presents the detailed tabulations of annual depreciation.

BASIS OF THE STUDY

Depreciation

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 and Net Salvage Estimates

The service life and net salvage 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 and net salvage 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 estimates of net salvage by account incorporated a review of experienced costs of removal and salvage related to plant retirements, and consideration of trends exhibited by the historical data. Each component of net salvage, i.e., cost of removal and salvage, was stated in dollars and as a percent of retirement.

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,

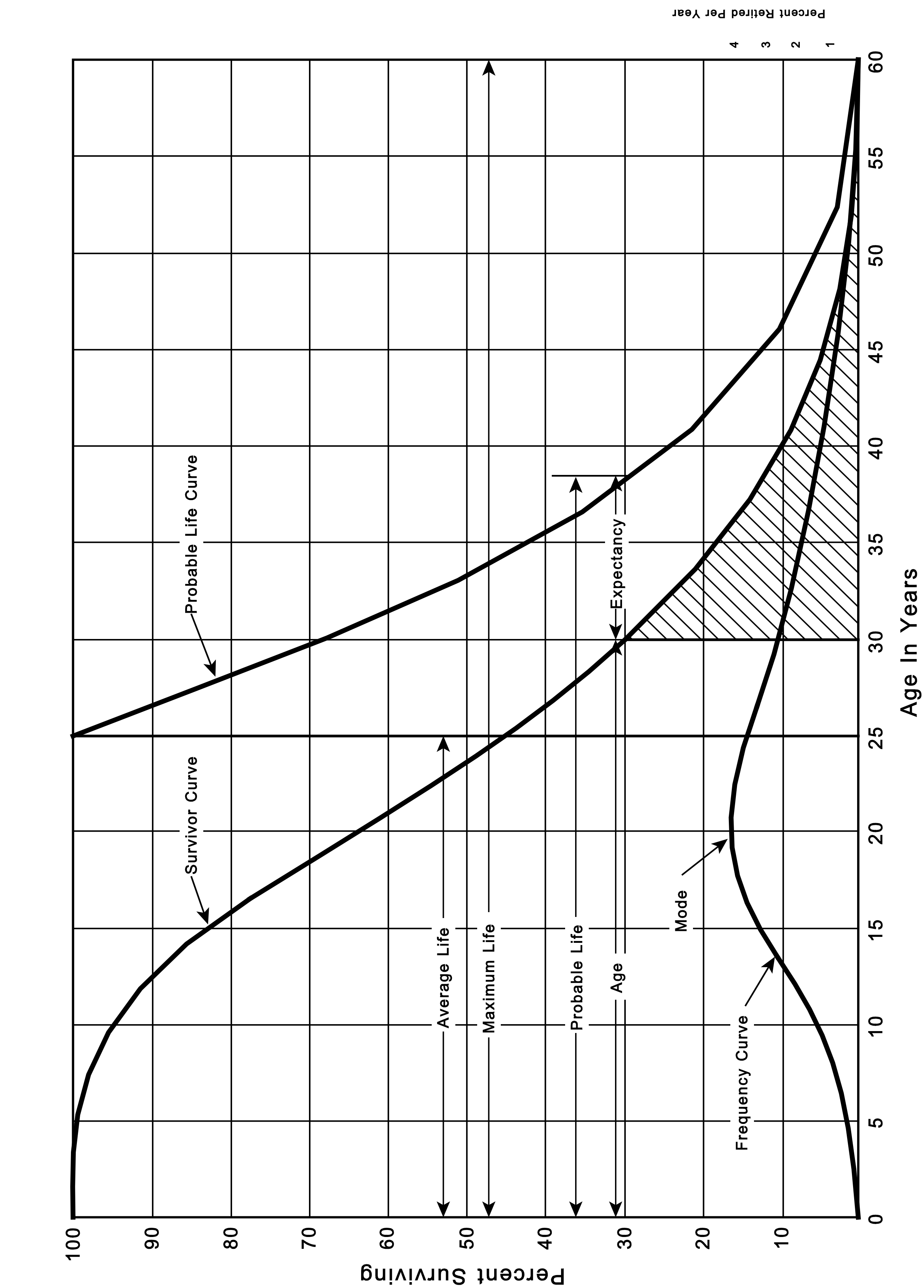

Figure 1. A Typical Survivor Curve and Derived Curves

Gannett Fleming

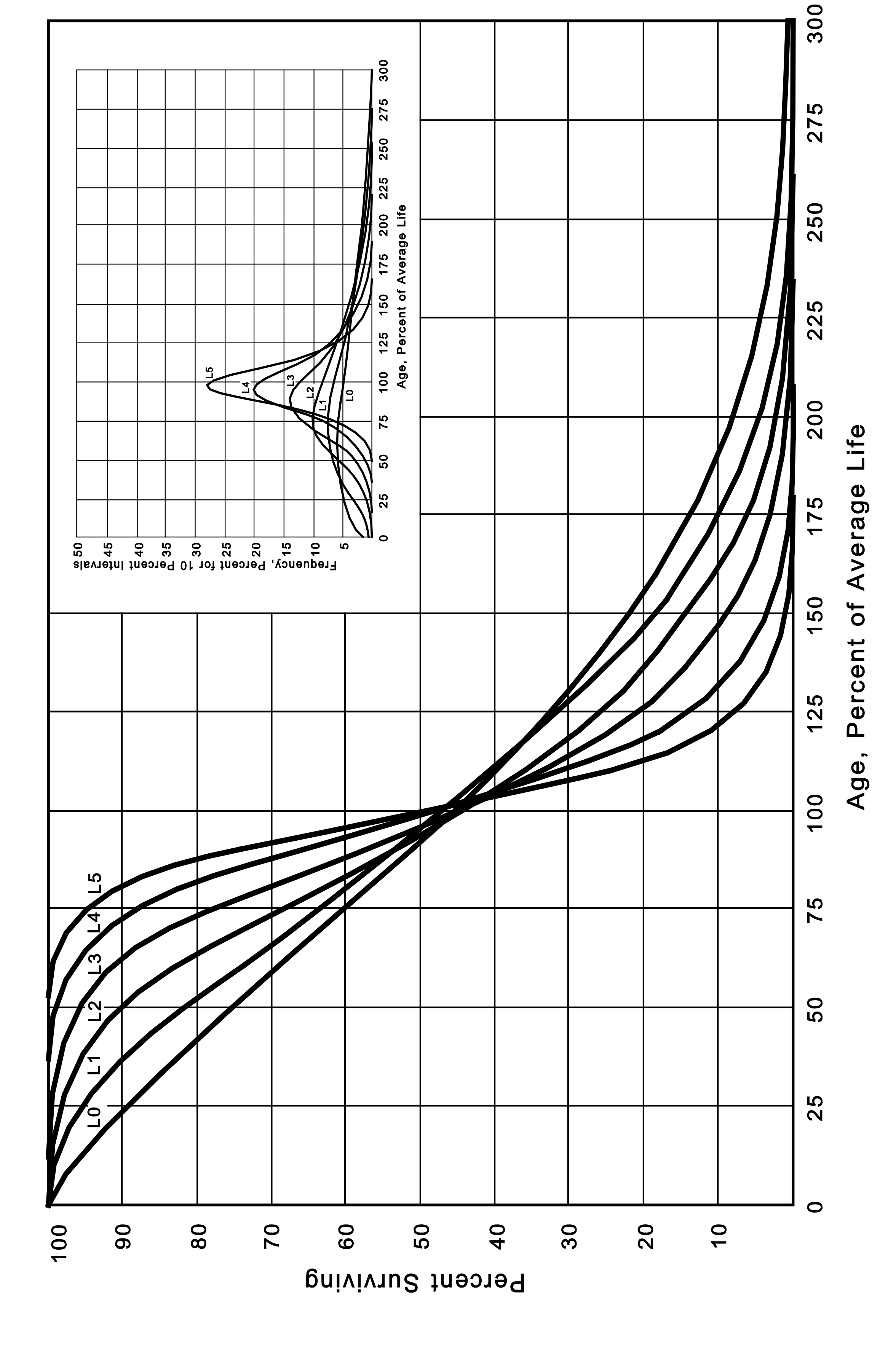

Figure 2. Left Modal or "L" Iowa Type Survivor Curves

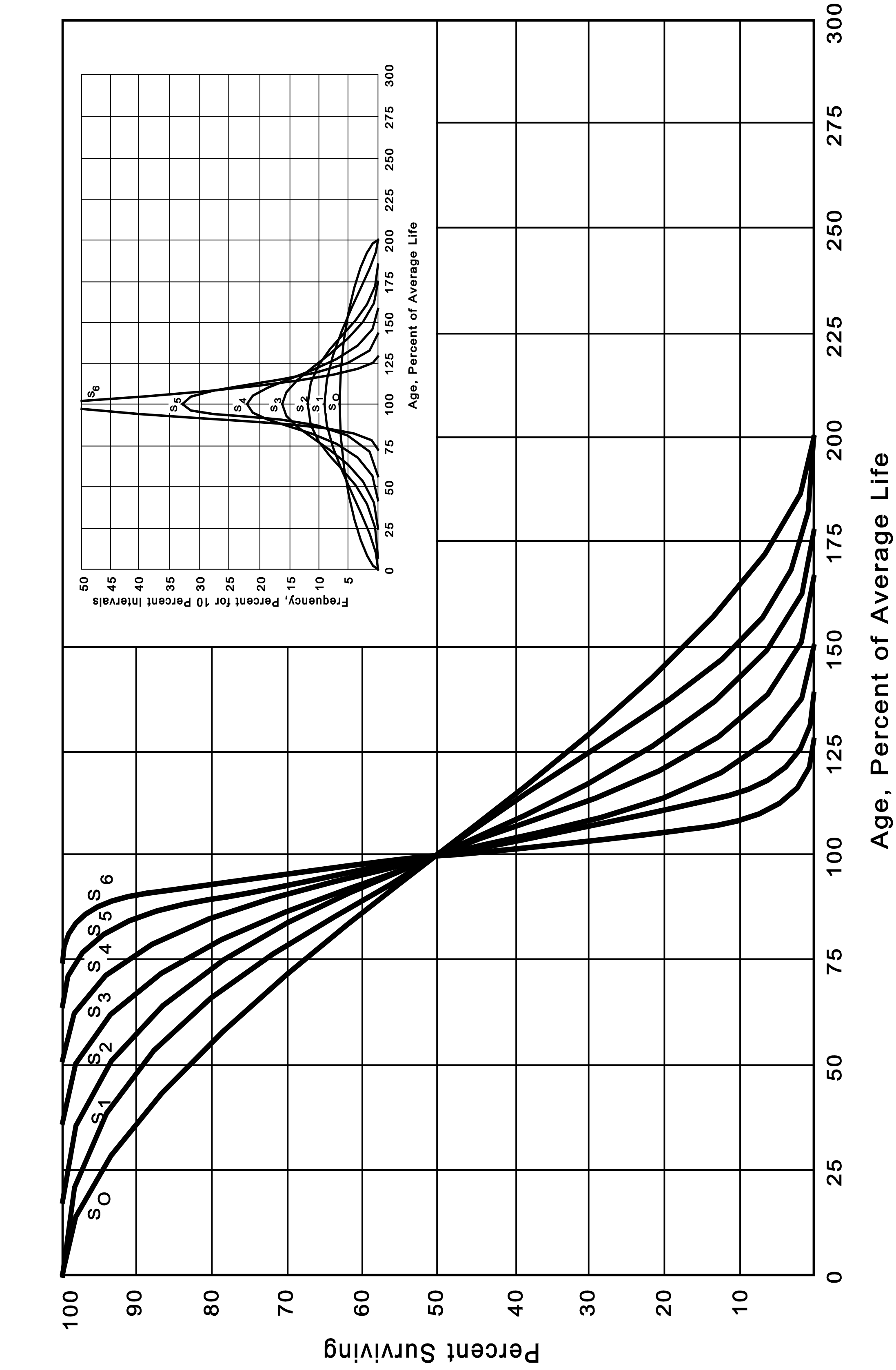

Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

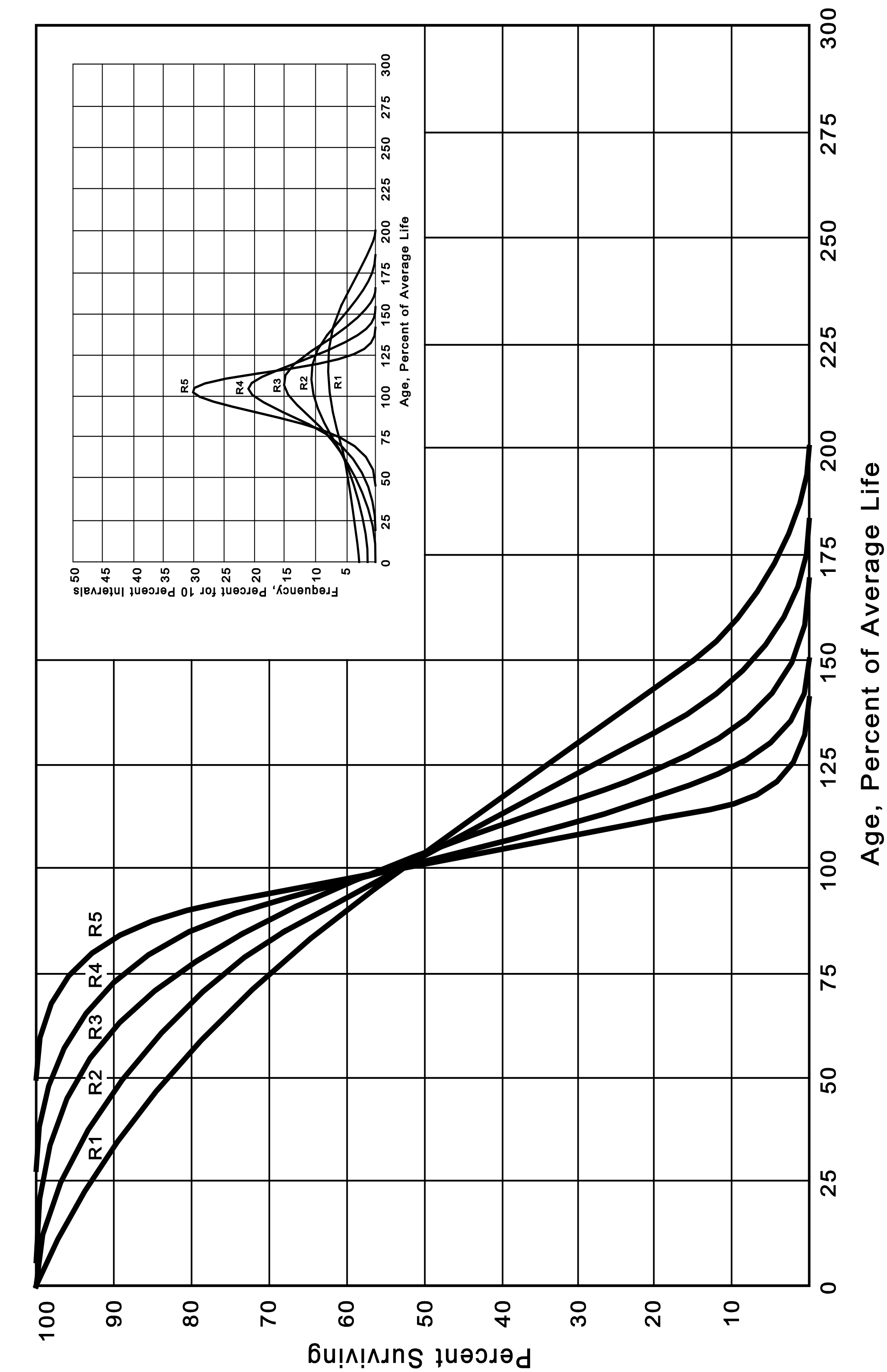

Figure 4. Right Modal or "R" Iowa Type Survivor Curves

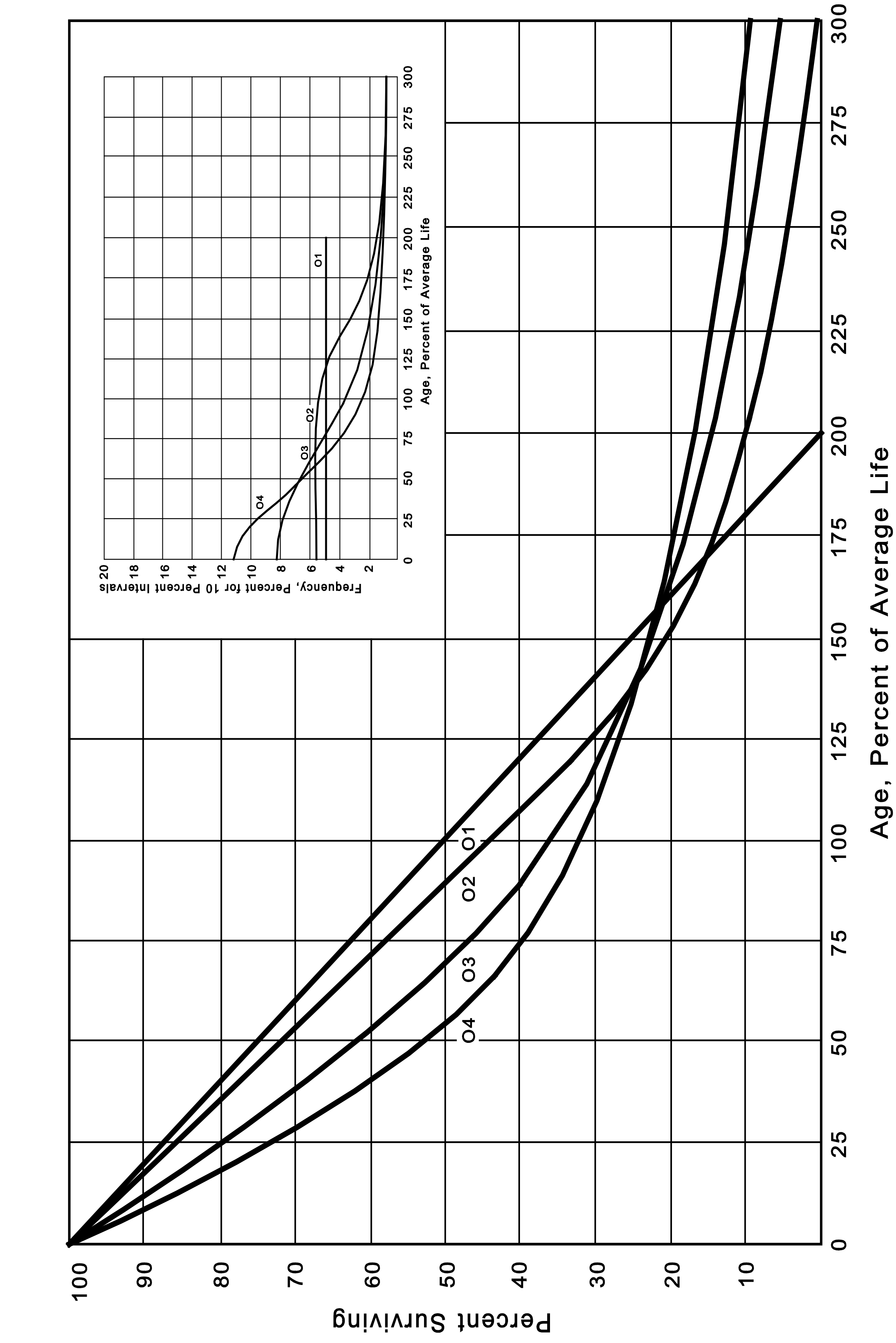

Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

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

[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.

Schedules of Annual Transactions in Plant Records

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:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

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SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018 | Placement Band 2004-2018

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)
	Retirements, Thousands of Dollars During Year											
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	

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SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018 | Placement Band 2004-2018

Year	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During	Age
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	-	-	-	-	-	-	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

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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 Placed	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total at Beginning of Age Interval	Age 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.

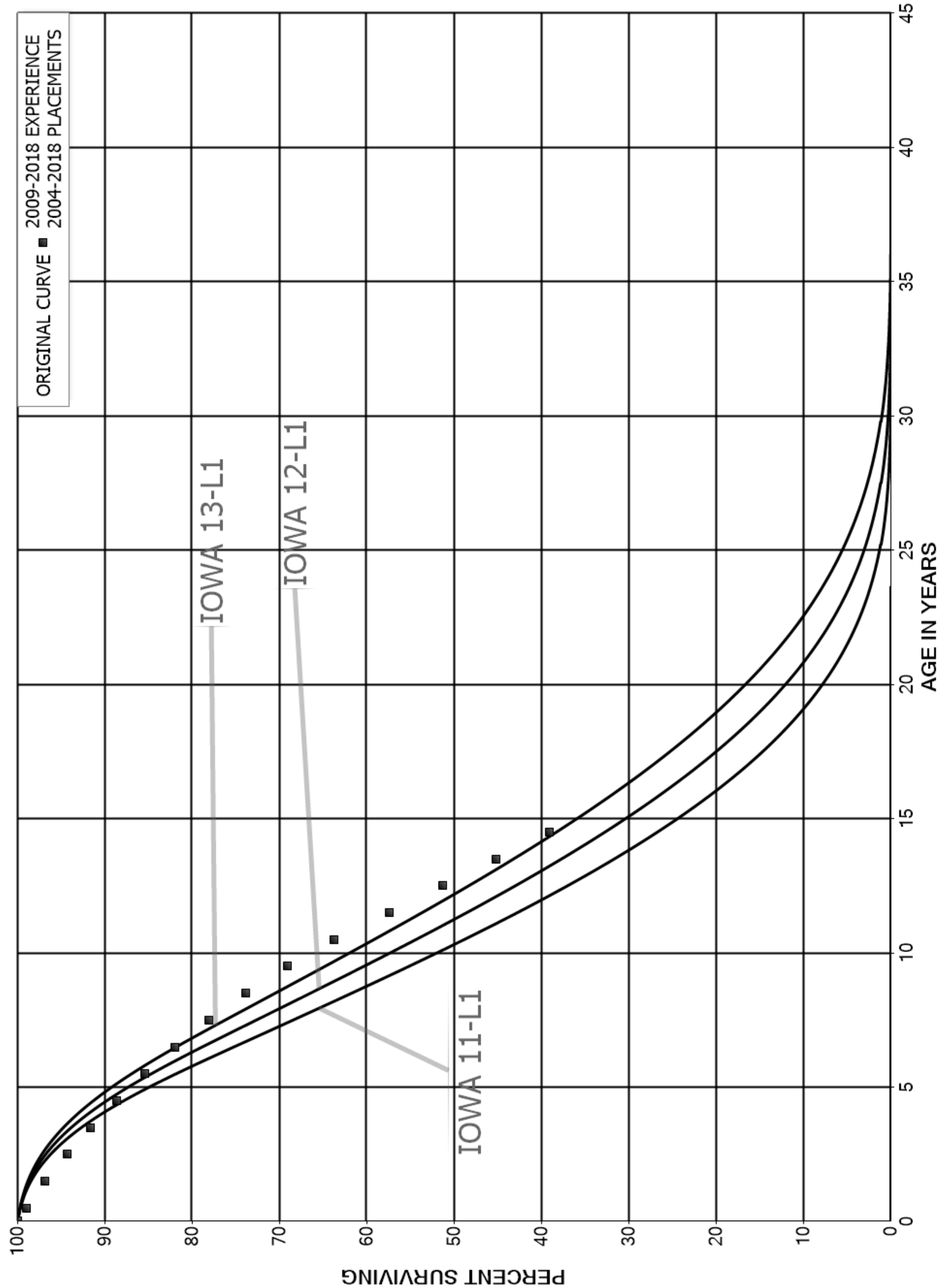
The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

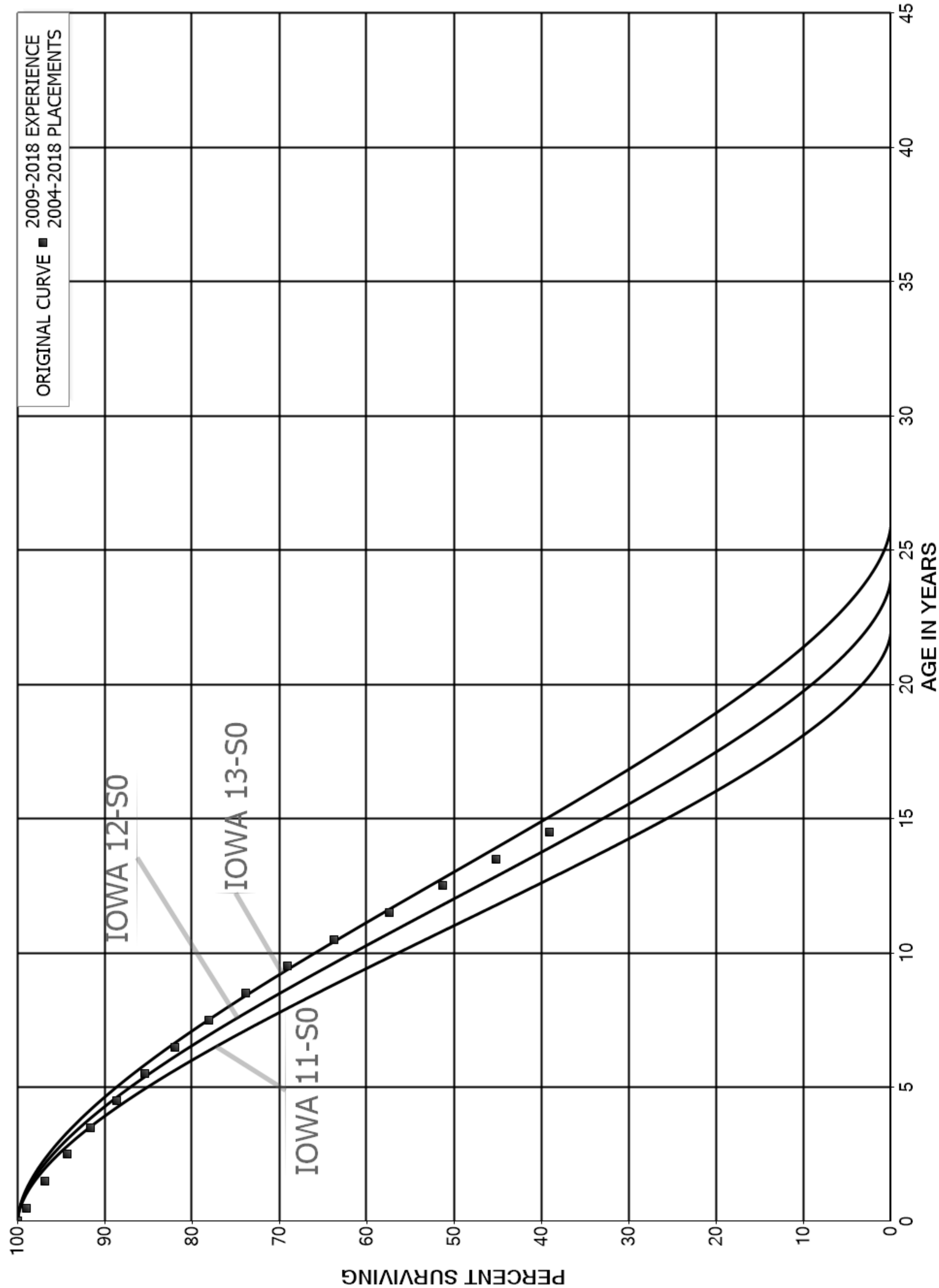
Smoothing the Original Survivor Curve

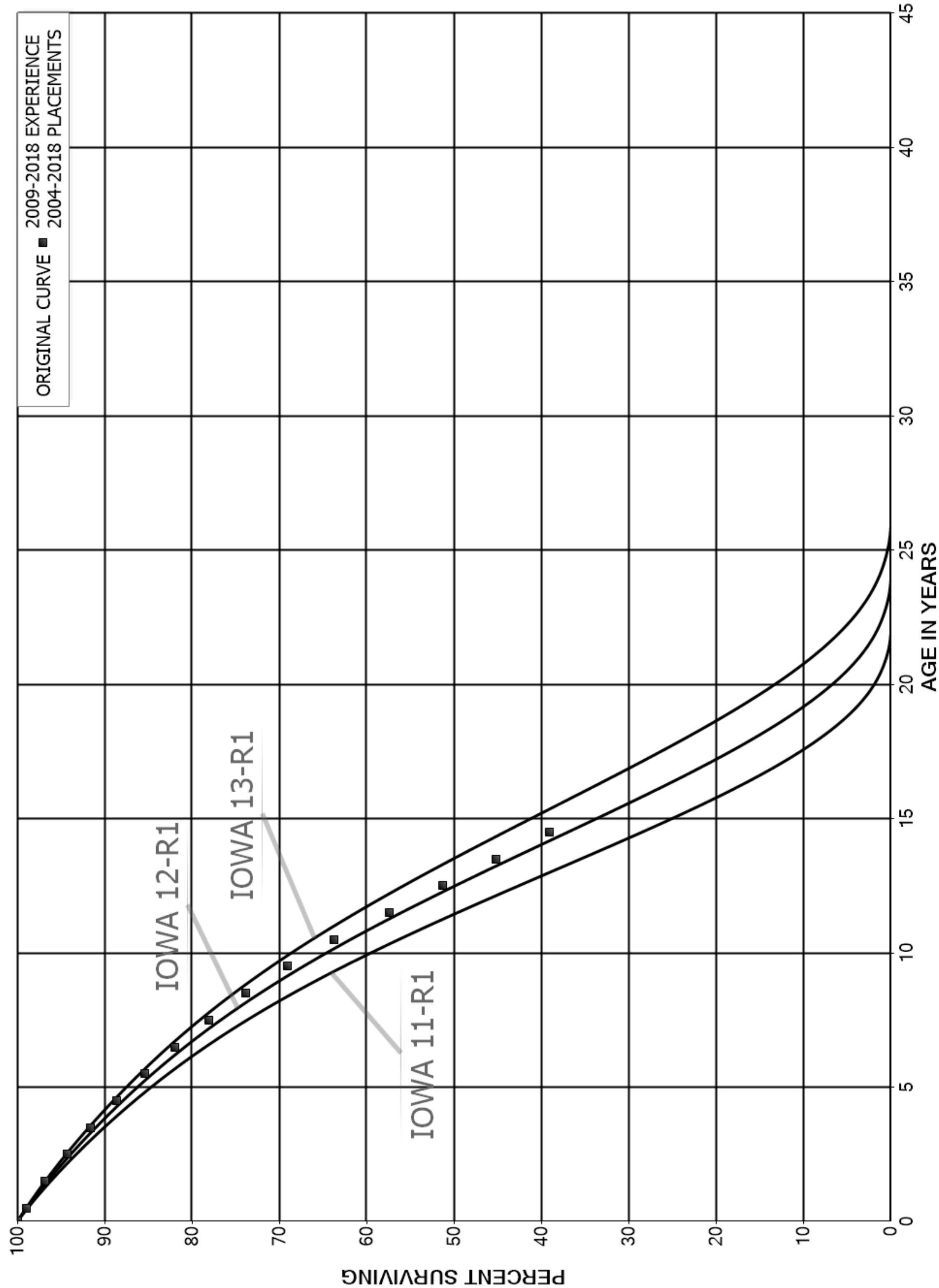
The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, 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.

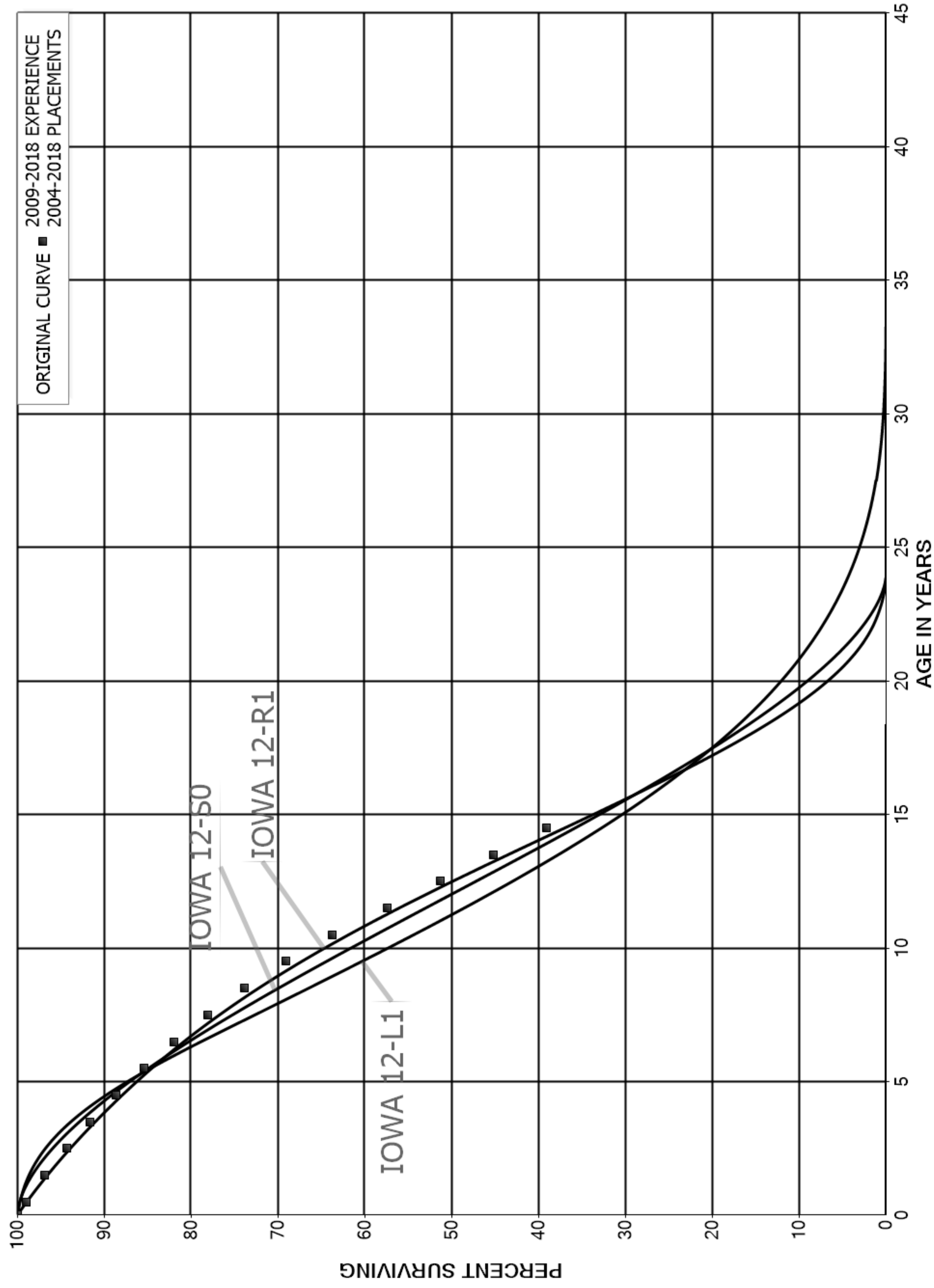
The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 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.


ORIGINAL CURVE ■ 2009-2018 EXPERIENCE
2004-2018 PLACEMENTS
IOWA 13-L1
IOWA 12-L1
IOWA 11-L1
PERCENT SURVIVING
AGE IN YEARS
0
5
10
15
20
25
30
35
40
45
100
90
80
70
60
50
40
30
20
10
0


ORIGINAL CURVE ■ 2009-2018 EXPERIENCE
2004-2018 PLACEMENTS
IOWA 12-S0
IOWA 13-S0
IOWA 11-S0
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
0
5
10
15
20
25
30
35
40
45


ORIGINAL CURVE ■ 2009-2018 EXPERIENCE
2004-2018 PLACEMENTS
IOWA 12-R1
IOWA 13-R1
IOWA 11-R1
AGE IN YEARS
PERCENT SURVIVING


ORIGINAL CURVE ■ 2009-2018 EXPERIENCE
2004-2018 PLACEMENTS
IOWA 12-S0
IOWA 12-R1
IOWA 12-L1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
15
25
35
45

PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

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 some plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good indications of the survivor patterns experienced. In other accounts the statistical analyses were inconclusive. Generally, the information external to the statistics led to a better understanding of the expected full life cycle of assets in each account. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

Account 353.00, Station Equipment is used to illustrate the manner in which the study was conducted for the group in the preceding list. Aged retirement and other plant accounting data were compiled for the years 1947 through 2018. These data were coded in the course of the Company's normal recordkeeping according to plant 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 data were analyzed by the retirement rate method of life analysis. The survivor curve chart for the account is presented on page VII-16 and the life tables for the experience bands, 1947-2018 and 1989-2018, are plotted on the chart that follows.

Typical service lives for transmission station equipment of other electric companies range from 45 to 55 years. The Iowa 53-R1.5 survivor curve is estimated to represent the future, inasmuch as it is a reasonable interpretation of the significant portion of the stub survivor curve through age 70, reflects the outlook of management and is within the typical range of lives for this account. The current estimate for this account is the 53-R1.5 survivor curve.

Another large account is Account 355.00, Poles and Fixtures. The estimate of survivor characteristics is based on the 1931-2018 experience band. As the survivor curve chart illustrates, the experience band represents similar life characteristics to the overall life cycle as the 60-R2 survivor curve, however, past experience (original curve) presents higher early age retirements than the R2-type curve. The selection of the R2-type curve reflects the continued increase of steel poles being installed instead of only wood, which will reduce the high levels of early age retirements. The 60-year average life is at the upper end of the range of lives used by others in the industry. Most other electric companies estimate lives between 50 and 65 years.

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other electric companies.

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled through 2018. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and salvage data are presented in the section titled "Net Salvage Statistics" for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the period, 2005 through 2018 by plant account were analyzed. The analyses contributed significantly toward the net salvage estimates of the depreciable plant.

Account 353.00, Station Equipment, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Net salvage data for the period 2005 through 2018 were analyzed for this account. The data include cost of removal, gross salvage and net salvage amounts and each of these amounts is expressed as a percent of the original cost of regular retirements. Three-year moving averages for the 2005-2007 through 2016-2018 periods were computed to smooth the annual amounts.

Cost of removal has fluctuated considerably during the fourteen year period. The primary cause during the recent period of cost of removal relates to the effort needed to replace control equipment within substations. Cost of removal for the most recent five years averaged 38 percent.

Gross salvage has been minimal throughout the period. The most recent five-year average of 0 percent gross salvage reflects recent trends and the overall value for station equipment.

The net salvage percent based on the overall period 2005 through 2018 is 14 percent negative net salvage and based on the most recent five-year period is 38 percent. Generally, the range of estimates made by other electric companies for Station Equipment is negative 5 to negative 25 percent. The net salvage estimate for station equipment is negative 20 percent, is within the range of other estimates and reflects the trend in recent years to more negative net salvage.

The net salvage percents for the remaining accounts were based on judgment incorporating estimates of previous studies of this and other electric utilities.

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 December 31, 2018, 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 December 31, 2018, 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:

$$\mathit{Ratio} = 1 - \frac{\mathit{Average\ Remaining\ Life}}{\mathit{Average\ Service\ Life}}.$$

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 December 31, 2018, 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 transmission plant in service as of December 31, 2018. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2018, is reasonable for a period of three to five years.

DESCRIPTION OF STATISTICAL SUPPORT

The service life and salvage 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.

The analyses of salvage data are presented in the section titled, "Net Salvage Statistics". The tabulations present annual cost of removal and salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of electric plant as of December 31, 2018, 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.

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 and net salvage percent 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 AND LIGHT COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC TRANSMISSION PLANT AS OF DECEMBER 31, 2018

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST AS OF DECEMBER 31, 2018 (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	ELECTRIC PLANT								
	MISCELLANEOUS INTANGIBLE PLANT								
303	MISCSELLANEOUS INTANGIBLE PLANT - SOFTWARE	7-SQ	0	9,563,615.86	6,562,169	3,001,447	677,311	*	4.4
	TOTAL MISCELLANEOUS INTANGIBLE PLANT			**9,563,615.86**	**6,562,169**	**3,001,447**	**677,311**		
	TRANSMISSION PLANT								
350.20	LAND RIGHTS	75-R3	0	40,169,440.62	17,805,088	22,364,353	612,853	1.53	36.5
352.00	STRUCTURES AND IMPROVEMENTS	75-R4	0	36,895,350.60	13,532,440	23,362,911	419,634	1.14	55.7
353.00	STATION EQUIPMENT	53-R1.5	(20)	782,373,478.80	146,282,152	792,566,023	19,023,512	2.43	41.7
354.00	TOWERS AND FIXTURES	80-R4	(10)	37,754,574.15	29,401,933	12,128,099	314,333	0.83	38.6
355.00	POLES AND FIXTURES	60-R2	(20)	324,651,293.38	75,848,661	313,732,891	6,344,631	1.95	49.4
356.00	OVERHEAD CONDUCTORS AND DEVICES	65-R2	(50)	294,511,099.88	97,422,188	344,344,462	7,222,141	2.45	47.7
356.10	OVERHEAD CONDUCTORS AND DEVICES - CLEARING	65-R2	0	34,363,537.56	12,552,755	21,810,783	373,878	1.09	58.3
357.00	UNDERGROUND CONDUIT	60-R2	0	1,864,993.38	967,007	897,986	25,831	1.39	34.8
358.00	UNDERGROUND CONDUCTORS AND DEVICES	55-R3	(15)	21,300,637.47	7,669,361	16,826,372	400,653	1.88	42.0
359.00	ROADS AND TRAILS	70-R4	0	2,392,822.25	1,185,024	1,207,798	26,389	1.10	45.8
	TOTAL TRANSMISSION PLANT			**1,576,277,228.09**	**402,666,609**	**1,549,241,678**	**34,763,855**	**2.21**	**44.6**
	GENERAL PLANT								
389.20	LAND RIGHTS	50-R3	0	1,147.95	458	690	45	3.92	15.3
390.10	STRUCTURES AND IMPROVEMENTS	50-R1.5	(5)	9,269,035.08	4,464,478	5,268,009	140,314	1.51	37.5
390.20	STRUCTURES AND IMPROVEMENTS - CLEARING	60-R3	0	1,134,293.60	926,854	207,440	5,223	0.46	39.7
391.10	OFFICE FURNITURE								
	FULLY ACCRUED			114,088.81	114,089	0	0	-	-
	AMORTIZED	25-SQ	0	800,487.99	555,425	245,063	32,028	4.00	7.7
	TOTAL OFFICE FURNITURE			*914,576.80*	*669,514*	*245,063*	*32,028*	*3.50*	
391.15	OFFICE EQUIPMENT	20-SQ	0	222,980.22	222,980	0	0	- **	-
391.20	PERSONAL COMPUTERS								
	FULLY ACCRUED			239,760.17	239,760	0	0	-	-
	AMORTIZED	5-SQ	0	626,979.38	330,270	296,709	125,425	20.00	2.4
	TOTAL PERSONAL COMPUTERS			*866,739.55*	*570,030*	*296,709*	*125,425*	*14.47*	
391.25	INFORMATION SYSTEMS	5-SQ	0	1,396.84	1,397	0	0	- ***	-
392.00	TRANSPORTATION EQUIPMENT	13-L2	5	527,045.93	279,280	221,414	20,258	3.84	10.9
393.00	STORES EQUIPMENT								
	FULLY ACCRUED			2,678.46	2,678	0	0	-	-
	AMORTIZED	30-SQ	0	133,215.94	101,610	31,606	4,439	3.33	7.1
	TOTAL STORES EQUIPMENT			*135,894.40*	*104,288*	*31,606*	*4,439*	*3.27*	
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT								
	FULLY ACCRUED			55,524.33	55,524	0	0	-	-
	AMORTIZED	25-SQ	0	1,719,268.55	859,345	859,924	68,776	4.00	12.5
	TOTAL TOOLS, SHOP AND GARAGE EQUIPMENT			*1,774,792.88*	*914,869*	*859,924*	*68,776*	*3.88*	

Gannett Fleming

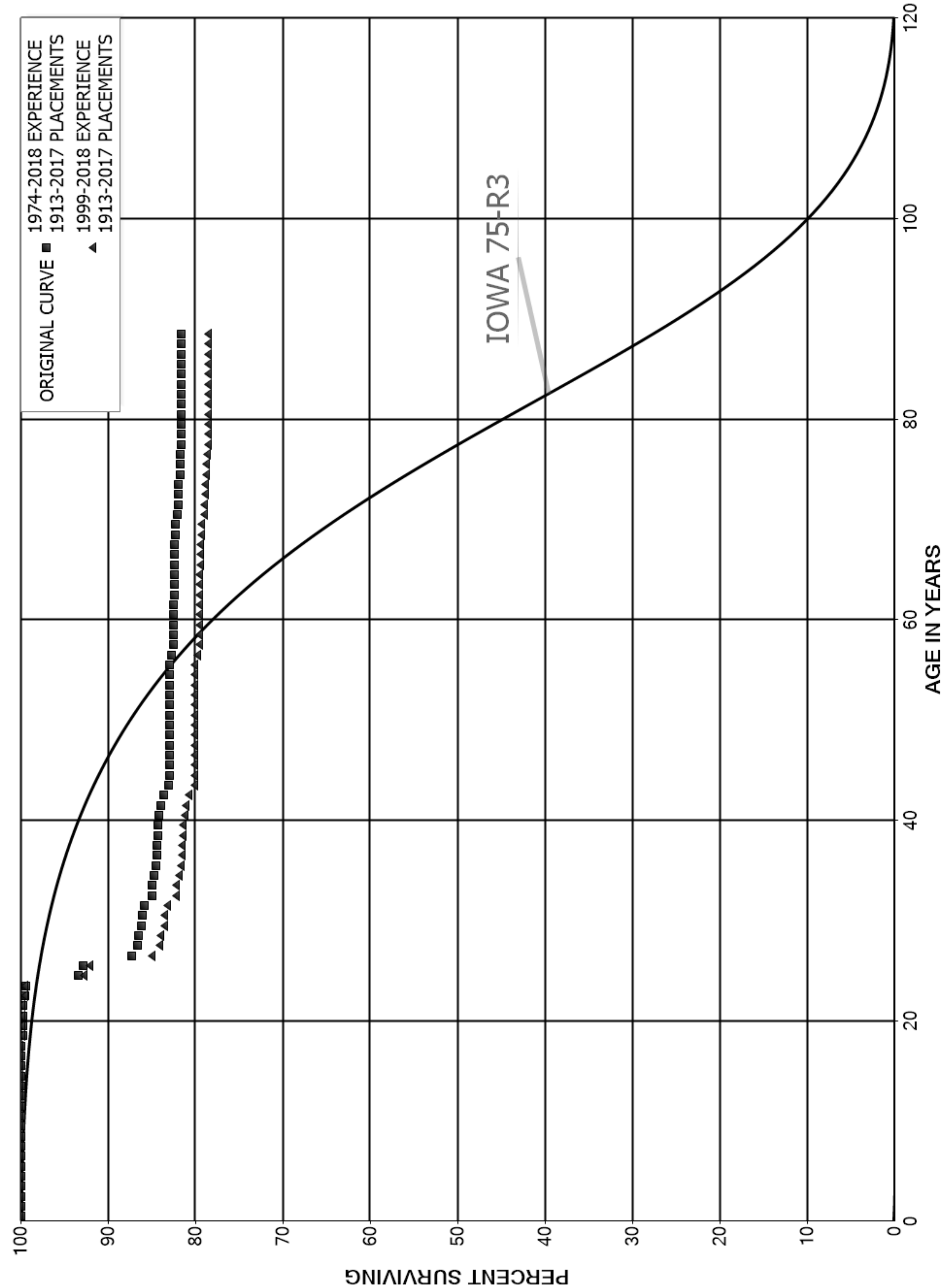
JERSEY CENTRAL POWER AND LIGHT COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC TRANSMISSION PLANT AS OF DECEMBER 31, 2018

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST AS OF DECEMBER 31, 2018 (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
395.00	LABORATORY EQUIPMENT								
	FULLY ACCRUED			6,534.64	6,535	0	0	-	-
	AMORTIZED	20-SQ	0	40,132.19	25,295	14,837	2,006	5.00	7.4
	TOTAL LABORATORY EQUIPMENT			*46,666.83*	*31,830*	*14,837*	*2,006*	*4.30*	
396.00	POWER OPERATED EQUIPMENT	20-S1	5	381,603.82	245,146	117,378	11,564	3.03	10.2
397.00	COMMUNICATION EQUIPMENT								
	FULLY ACCRUED			2,990,971.60	2,990,972	0	0	-	-
	AMORTIZED	20-SQ	0	2,606,171.36	358,160	2,248,011	130,338	5.00	17.2
	TOTAL COMMUNICATION EQUIPMENT			*5,597,142.96*	*3,349,132*	*2,248,011*	*130,338*	*2.33*	
398.00	MISCELLANEOUS EQUIPMENT								
	FULLY ACCRUED			25,863.09	25,863	0	0	-	-
	AMORTIZED	20-SQ	0	112,034.41	71,945	40,089	5,607	5.00	7.1
	TOTAL MISCELLANEOUS EQUIPMENT			*137,897.50*	*97,808*	*40,089*	*5,607*	*4.07*	
	TOTAL GENERAL PLANT			**21,011,214.36**	**11,878,064**	**9,551,170**	**546,023**	**2.60**	**17.5**
	UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION								
391.10	OFFICE FURNITURE				(71,041)		14,208 ****		
391.15	OFFICE EQUIPMENT				(41,010)		8,202 ****		
391.20	PERSONAL COMPUTERS				(660,706)		132,141 ****		
391.25	INFORMATION SYSTEMS				(75)		15 ****		
393.00	STORES EQUIPMENT				4,534		(907) ****		
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT				(62,190)		12,438 ****		
395.00	LABORATORY EQUIPMENT				14,837		(2,967) ****		
397.00	COMMUNICATION EQUIPMENT				(204,357)		40,871 ****		
398.00	MISCELLANEOUS EQUIPMENT				7,781		(1,556) ****		
	TOTAL UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION				**(1,012,227)**		**202,445**		
	TOTAL DEPRECIABLE ELECTRIC PLANT			**1,606,852,058.31**	**420,094,615**	**1,561,794,295**	**36,189,634**	**2.25**	
	NONDEPRECIABLE PLANT								
350.10	LAND			4,446,383.56	(84)				
359.10	ARC TRANSMISSION			3,410.49	1,503				
389.10	LAND			155,001.18					
399.10	ARC GENERAL PLANT			159,885.62	27,213				
	TOTAL NONDEPRECIABLE PLANT			**4,764,680.85**	**28,632**				
	TOTAL ELECTRIC PLANT			**1,611,616,739.16**	**420,123,247**				

* 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.
**** 5-Year amortization of unrecovered reserve related to utilization of amortization accounting.

PART VII. SERVICE LIFE STATISTICS


ORIGINAL CURVE ■ 1974-2018 EXPERIENCE
1913-2017 PLACEMENTS
▲ 1999-2018 EXPERIENCE
1913-2017 PLACEMENTS
IOWA 75-R3
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
0
20
40
60
80
100
120

PLACEMENT BAND 1913-2017 EXPERIENCE BAND 1974-2018

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	7,827,863	0	0.0000	1.0000	100.00
0.5	8,945,459	9	0.0000	1.0000	100.00
1.5	9,044,615	5	0.0000	1.0000	100.00
2.5	4,575,512	7	0.0000	1.0000	100.00
3.5	4,732,355	6	0.0000	1.0000	100.00
4.5	6,060,652	0	0.0000	1.0000	100.00
5.5	6,258,372	1	0.0000	1.0000	100.00
6.5	6,301,128	1	0.0000	1.0000	100.00
7.5	6,572,763	39	0.0000	1.0000	100.00
8.5	7,260,960	19	0.0000	1.0000	100.00
9.5	16,032,407	74	0.0000	1.0000	100.00
10.5	16,290,106	43	0.0000	1.0000	100.00
11.5	16,472,491	76	0.0000	1.0000	100.00
12.5	16,831,911	53	0.0000	1.0000	100.00
13.5	16,903,502	35	0.0000	1.0000	100.00
14.5	16,956,749	2,039	0.0001	0.9999	100.00
15.5	17,256,744	68	0.0000	1.0000	99.98
16.5	17,357,114	38	0.0000	1.0000	99.98
17.5	17,630,537	41,636	0.0024	0.9976	99.98
18.5	18,650,202	1,024	0.0001	0.9999	99.75
19.5	17,782,169	1,455	0.0001	0.9999	99.74
20.5	17,998,417	1,538	0.0001	0.9999	99.73
21.5	18,416,717	41,164	0.0022	0.9978	99.73
22.5	18,484,827	13,230	0.0007	0.9993	99.50
23.5	19,705,089	1,193,748	0.0606	0.9394	99.43
24.5	19,304,923	119,076	0.0062	0.9938	93.41
25.5	22,018,151	1,311,184	0.0596	0.9404	92.83
26.5	20,674,445	161,095	0.0078	0.9922	87.30
27.5	20,968,843	17,286	0.0008	0.9992	86.62
28.5	21,457,882	90,378	0.0042	0.9958	86.55
29.5	22,655,683	23,843	0.0011	0.9989	86.19
30.5	22,783,384	61,795	0.0027	0.9973	86.10
31.5	22,687,829	238,315	0.0105	0.9895	85.86
32.5	24,959,037	2,283	0.0001	0.9999	84.96
33.5	26,213,240	81,323	0.0031	0.9969	84.95
34.5	25,767,652	59,578	0.0023	0.9977	84.69
35.5	26,119,093	17,334	0.0007	0.9993	84.49
36.5	25,630,436	8,858	0.0003	0.9997	84.44
37.5	17,805,452	24,844	0.0014	0.9986	84.41
38.5	17,945,159	1,590	0.0001	0.9999	84.29

PLACEMENT BAND 1913-2017 EXPERIENCE BAND 1974-2018

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	17,932,537	33,862	0.0019	0.9981	84.28
40.5	17,902,263	36,031	0.0020	0.9980	84.12
41.5	18,386,421	70,062	0.0038	0.9962	83.96
42.5	17,257,896	129,058	0.0075	0.9925	83.64
43.5	17,192,819	468	0.0000	1.0000	83.01
44.5	17,095,306	654	0.0000	1.0000	83.01
45.5	16,883,146	335	0.0000	1.0000	83.00
46.5	16,801,401	1,462	0.0001	0.9999	83.00
47.5	15,571,079	190	0.0000	1.0000	83.00
48.5	14,774,672	512	0.0000	1.0000	82.99
49.5	11,916,990	652	0.0001	0.9999	82.99
50.5	11,712,217	274	0.0000	1.0000	82.99
51.5	11,231,690	192	0.0000	1.0000	82.99
52.5	10,604,940	102	0.0000	1.0000	82.98
53.5	9,294,777	39	0.0000	1.0000	82.98
54.5	8,159,519	27	0.0000	1.0000	82.98
55.5	7,944,715	25,699	0.0032	0.9968	82.98
56.5	5,567,219	16,074	0.0029	0.9971	82.71
57.5	4,303,893	68	0.0000	1.0000	82.48
58.5	4,186,193	333	0.0001	0.9999	82.47
59.5	3,548,234	123	0.0000	1.0000	82.47
60.5	3,276,989	94	0.0000	1.0000	82.46
61.5	2,267,459	1,178	0.0005	0.9995	82.46
62.5	2,374,225	129	0.0001	0.9999	82.42
63.5	2,392,563	312	0.0001	0.9999	82.41
64.5	2,948,517	118	0.0000	1.0000	82.40
65.5	2,216,982	26	0.0000	1.0000	82.40
66.5	2,240,402	54	0.0000	1.0000	82.40
67.5	2,198,021	2,153	0.0010	0.9990	82.40
68.5	2,251,376	1,991	0.0009	0.9991	82.32
69.5	2,181,271	5,711	0.0026	0.9974	82.24
70.5	2,165,125	1,150	0.0005	0.9995	82.03
71.5	2,154,486	1,291	0.0006	0.9994	81.99
72.5	2,149,259	1,178	0.0005	0.9995	81.94
73.5	2,142,563	3,119	0.0015	0.9985	81.89
74.5	2,133,423	424	0.0002	0.9998	81.77
75.5	2,092,615	681	0.0003	0.9997	81.76
76.5	2,077,452	4,083	0.0020	0.9980	81.73
77.5	2,003,726	38	0.0000	1.0000	81.57
78.5	1,959,686	11	0.0000	1.0000	81.57

PLACEMENT BAND 1913-2017 EXPERIENCE BAND 1974-2018

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	1,955,245		0.0000	1.0000	81.57
80.5	1,729,874		0.0000	1.0000	81.57
81.5	1,720,167		0.0000	1.0000	81.57
82.5	1,697,588		0.0000	1.0000	81.57
83.5	1,692,528		0.0000	1.0000	81.57
84.5	1,692,306		0.0000	1.0000	81.57
85.5	1,686,300	11	0.0000	1.0000	81.57
86.5	1,393,051	26	0.0000	1.0000	81.57
87.5	1,150,366	3	0.0000	1.0000	81.56
88.5	506,024	5	0.0000	1.0000	81.56
89.5	447,510	1	0.0000	1.0000	81.56
90.5	405,770		0.0000	1.0000	81.56
91.5	324,322		0.0000	1.0000	81.56
92.5	33,824		0.0000	1.0000	81.56
93.5	19,473		0.0000	1.0000	81.56
94.5	1,640		0.0000	1.0000	81.56
95.5	1,640		0.0000	1.0000	81.56
96.5	1,640		0.0000	1.0000	81.56
97.5	1,640		0.0000	1.0000	81.56
98.5	1,640		0.0000	1.0000	81.56
99.5	1,640		0.0000	1.0000	81.56
100.5	1,640		0.0000	1.0000	81.56
101.5	1,640		0.0000	1.0000	81.56
102.5	1,640		0.0000	1.0000	81.56
103.5	1,640		0.0000	1.0000	81.56
104.5	1,091		0.0000	1.0000	81.56
105.5					81.56

PLACEMENT BAND 1913-2017 EXPERIENCE BAND 1999-2018

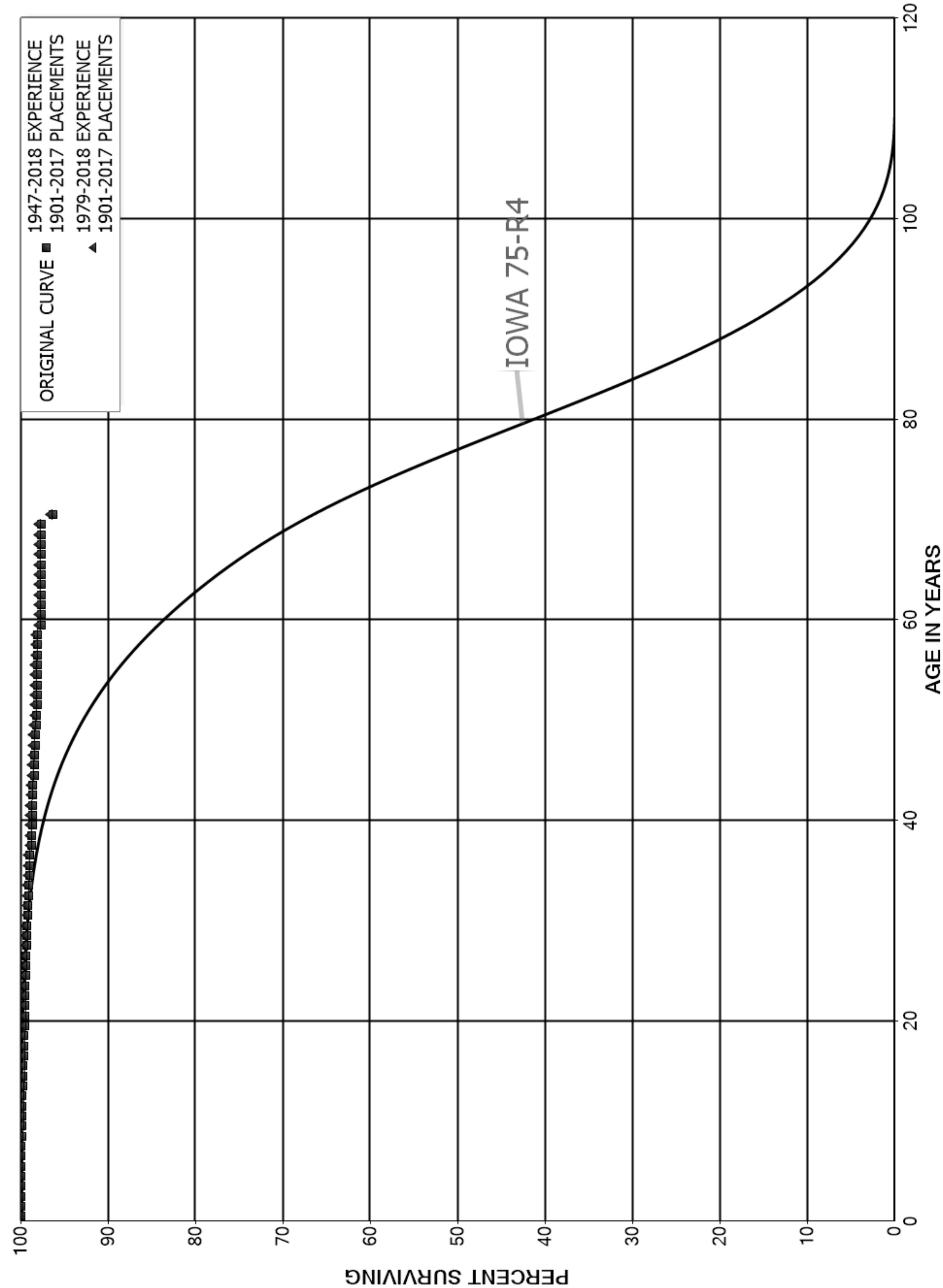
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,450,923	0	0.0000	1.0000	100.00
0.5	6,504,579	9	0.0000	1.0000	100.00
1.5	6,461,556	5	0.0000	1.0000	100.00
2.5	1,230,082	7	0.0000	1.0000	100.00
3.5	1,234,907	6	0.0000	1.0000	100.00
4.5	1,275,189	0	0.0000	1.0000	100.00
5.5	1,316,584	1	0.0000	1.0000	100.00
6.5	2,749,899	1	0.0000	1.0000	100.00
7.5	2,931,101	39	0.0000	1.0000	100.00
8.5	4,375,268	19	0.0000	1.0000	100.00
9.5	4,620,455	74	0.0000	1.0000	100.00
10.5	5,472,914	43	0.0000	1.0000	100.00
11.5	5,818,758	76	0.0000	1.0000	99.99
12.5	5,915,759	53	0.0000	1.0000	99.99
13.5	5,946,741	34	0.0000	1.0000	99.99
14.5	6,729,689	2,039	0.0003	0.9997	99.99
15.5	6,977,750	68	0.0000	1.0000	99.96
16.5	7,806,274	38	0.0000	1.0000	99.96
17.5	16,694,337	41,636	0.0025	0.9975	99.96
18.5	16,688,359	1,024	0.0001	0.9999	99.71
19.5	15,985,650	1,455	0.0001	0.9999	99.70
20.5	16,095,041	1,538	0.0001	0.9999	99.70
21.5	16,366,368	40,527	0.0025	0.9975	99.69
22.5	17,440,294	13,230	0.0008	0.9992	99.44
23.5	17,518,593	1,193,748	0.0681	0.9319	99.36
24.5	16,737,025	119,076	0.0071	0.9929	92.59
25.5	17,007,195	1,311,184	0.0771	0.9229	91.93
26.5	15,569,640	160,245	0.0103	0.9897	84.85
27.5	16,577,273	17,286	0.0010	0.9990	83.97
28.5	17,224,189	90,378	0.0052	0.9948	83.89
29.5	19,900,823	23,843	0.0012	0.9988	83.45
30.5	19,110,932	61,795	0.0032	0.9968	83.35
31.5	19,311,264	238,315	0.0123	0.9877	83.08
32.5	19,644,145	2,283	0.0001	0.9999	82.05
33.5	20,995,027	81,323	0.0039	0.9961	82.04
34.5	21,535,061	59,578	0.0028	0.9972	81.72
35.5	21,444,419	17,334	0.0008	0.9992	81.50
36.5	23,263,061	8,858	0.0004	0.9996	81.43
37.5	15,690,605	24,844	0.0016	0.9984	81.40
38.5	15,811,333	1,405	0.0001	0.9999	81.27

PLACEMENT BAND 1913-2017 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	16,214,955	33,862	0.0021	0.9979	81.26
40.5	16,357,847	36,031	0.0022	0.9978	81.09
41.5	17,066,919	70,062	0.0041	0.9959	80.92
42.5	16,101,879	129,058	0.0080	0.9920	80.58
43.5	16,157,796	468	0.0000	1.0000	79.94
44.5	15,908,132	654	0.0000	1.0000	79.94
45.5	16,406,377	335	0.0000	1.0000	79.93
46.5	16,313,939	1,462	0.0001	0.9999	79.93
47.5	15,205,710	190	0.0000	1.0000	79.92
48.5	14,644,924	512	0.0000	1.0000	79.92
49.5	11,867,483	652	0.0001	0.9999	79.92
50.5	11,684,077	274	0.0000	1.0000	79.92
51.5	11,173,588	192	0.0000	1.0000	79.91
52.5	10,533,104	102	0.0000	1.0000	79.91
53.5	9,158,024	39	0.0000	1.0000	79.91
54.5	8,014,383	27	0.0000	1.0000	79.91
55.5	7,834,585	24,280	0.0031	0.9969	79.91
56.5	5,245,577	16,074	0.0031	0.9969	79.66
57.5	4,036,858	68	0.0000	1.0000	79.42
58.5	3,916,763	333	0.0001	0.9999	79.42
59.5	3,279,788	123	0.0000	1.0000	79.41
60.5	3,235,702	94	0.0000	1.0000	79.41
61.5	2,231,017	1,178	0.0005	0.9995	79.41
62.5	2,064,604	129	0.0001	0.9999	79.36
63.5	1,847,997	312	0.0002	0.9998	79.36
64.5	1,751,450	118	0.0001	0.9999	79.35
65.5	966,835	26	0.0000	1.0000	79.34
66.5	1,241,299	54	0.0000	1.0000	79.34
67.5	1,363,279	2,153	0.0016	0.9984	79.33
68.5	1,773,359	1,991	0.0011	0.9989	79.21
69.5	1,747,684	5,711	0.0033	0.9967	79.12
70.5	1,755,669	1,150	0.0007	0.9993	78.86
71.5	1,827,467	1,291	0.0007	0.9993	78.81
72.5	2,116,627	1,178	0.0006	0.9994	78.75
73.5	2,124,476	3,119	0.0015	0.9985	78.71
74.5	2,133,423	424	0.0002	0.9998	78.59
75.5	2,092,615	681	0.0003	0.9997	78.58
76.5	2,077,452	4,083	0.0020	0.9980	78.55
77.5	2,003,726	38	0.0000	1.0000	78.40
78.5	1,959,686	11	0.0000	1.0000	78.40

PLACEMENT BAND 1913-2017 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	1,955,245		0.0000	1.0000	78.40
80.5	1,729,312		0.0000	1.0000	78.40
81.5	1,718,482		0.0000	1.0000	78.40
82.5	1,695,903		0.0000	1.0000	78.40
83.5	1,690,843		0.0000	1.0000	78.40
84.5	1,691,182		0.0000	1.0000	78.40
85.5	1,686,300	11	0.0000	1.0000	78.40
86.5	1,393,051	26	0.0000	1.0000	78.40
87.5	1,150,366	3	0.0000	1.0000	78.40
88.5	506,024	5	0.0000	1.0000	78.40
89.5	447,510	1	0.0000	1.0000	78.39
90.5	405,770		0.0000	1.0000	78.39
91.5	324,322		0.0000	1.0000	78.39
92.5	33,824		0.0000	1.0000	78.39
93.5	19,473		0.0000	1.0000	78.39
94.5	1,640		0.0000	1.0000	78.39
95.5	1,640		0.0000	1.0000	78.39
96.5	1,640		0.0000	1.0000	78.39
97.5	1,640		0.0000	1.0000	78.39
98.5	1,640		0.0000	1.0000	78.39
99.5	1,640		0.0000	1.0000	78.39
100.5	1,640		0.0000	1.0000	78.39
101.5	1,640		0.0000	1.0000	78.39
102.5	1,640		0.0000	1.0000	78.39
103.5	1,640		0.0000	1.0000	78.39
104.5	1,091		0.0000	1.0000	78.39
105.5					78.39


ORIGINAL CURVE ■ 1947-2018 EXPERIENCE 1901-2017 PLACEMENTS
▲ 1979-2018 EXPERIENCE 1901-2017 PLACEMENTS
IOWA 75-R4
PERCENT SURVIVING
AGE IN YEARS
0
20
40
60
80
100
120
0
10
20
30
40
50
60
70
80
90
100

PLACEMENT BAND 1901-2017 EXPERIENCE BAND 1947-2018

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	18,943,768	0	0.0000	1.0000	100.00
0.5	19,417,568	0	0.0000	1.0000	100.00
1.5	20,131,574	1,637	0.0001	0.9999	100.00
2.5	21,828,597	984	0.0000	1.0000	99.99
3.5	19,447,117	2,641	0.0001	0.9999	99.99
4.5	18,798,822	788	0.0000	1.0000	99.97
5.5	19,407,849	3,408	0.0002	0.9998	99.97
6.5	19,907,035	11,303	0.0006	0.9994	99.95
7.5	19,910,736	1,229	0.0001	0.9999	99.90
8.5	20,699,478	8,213	0.0004	0.9996	99.89
9.5	20,134,923	6,241	0.0003	0.9997	99.85
10.5	19,517,737	742	0.0000	1.0000	99.82
11.5	19,713,242	5,918	0.0003	0.9997	99.81
12.5	18,188,880	13,083	0.0007	0.9993	99.78
13.5	17,650,093	3,343	0.0002	0.9998	99.71
14.5	17,673,067	2,157	0.0001	0.9999	99.69
15.5	17,894,604	2,375	0.0001	0.9999	99.68
16.5	17,893,780	2,323	0.0001	0.9999	99.67
17.5	17,864,283	13,410	0.0008	0.9992	99.66
18.5	17,910,241	8,250	0.0005	0.9995	99.58
19.5	17,921,876	3,692	0.0002	0.9998	99.54
20.5	18,115,254	3,936	0.0002	0.9998	99.51
21.5	18,042,973	511	0.0000	1.0000	99.49
22.5	17,519,850	4,691	0.0003	0.9997	99.49
23.5	16,640,960	4,004	0.0002	0.9998	99.46
24.5	15,892,737	5,843	0.0004	0.9996	99.44
25.5	16,168,948	2,773	0.0002	0.9998	99.40
26.5	14,513,993	16,299	0.0011	0.9989	99.39
27.5	14,147,794	2,820	0.0002	0.9998	99.27
28.5	13,498,903	1,592	0.0001	0.9999	99.25
29.5	12,271,931	9,863	0.0008	0.9992	99.24
30.5	10,402,499	3,123	0.0003	0.9997	99.16
31.5	8,574,077	1,573	0.0002	0.9998	99.13
32.5	8,185,036	7,582	0.0009	0.9991	99.12
33.5	8,013,855	3,349	0.0004	0.9996	99.02
34.5	7,881,833	4,227	0.0005	0.9995	98.98
35.5	7,859,957	2,317	0.0003	0.9997	98.93
36.5	7,192,343	14,611	0.0020	0.9980	98.90
37.5	6,676,075	1,315	0.0002	0.9998	98.70
38.5	6,668,283	635	0.0001	0.9999	98.68

PLACEMENT BAND 1901-2017 EXPERIENCE BAND 1947-2018

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	6,409,066	2,746	0.0004	0.9996	98.67
40.5	6,325,149	817	0.0001	0.9999	98.63
41.5	5,695,384	1,691	0.0003	0.9997	98.61
42.5	5,597,682	1,141	0.0002	0.9998	98.59
43.5	5,157,033	6,652	0.0013	0.9987	98.57
44.5	4,872,423	1,935	0.0004	0.9996	98.44
45.5	4,631,157	1,354	0.0003	0.9997	98.40
46.5	4,172,485	2,558	0.0006	0.9994	98.37
47.5	3,885,283	158	0.0000	1.0000	98.31
48.5	3,496,598	5,113	0.0015	0.9985	98.31
49.5	2,915,359	206	0.0001	0.9999	98.16
50.5	2,807,502	2,328	0.0008	0.9992	98.16
51.5	2,349,975	87	0.0000	1.0000	98.07
52.5	1,864,994	95	0.0001	0.9999	98.07
53.5	1,540,402	135	0.0001	0.9999	98.07
54.5	1,290,133	12	0.0000	1.0000	98.06
55.5	821,003	368	0.0004	0.9996	98.06
56.5	709,608	1	0.0000	1.0000	98.01
57.5	627,054	6	0.0000	1.0000	98.01
58.5	597,354	2,126	0.0036	0.9964	98.01
59.5	466,060	112	0.0002	0.9998	97.66
60.5	384,635	25	0.0001	0.9999	97.64
61.5	368,538	6	0.0000	1.0000	97.63
62.5	322,702	1	0.0000	1.0000	97.63
63.5	317,124		0.0000	1.0000	97.63
64.5	188,777		0.0000	1.0000	97.63
65.5	154,954		0.0000	1.0000	97.63
66.5	158,935		0.0000	1.0000	97.63
67.5	249,094		0.0000	1.0000	97.63
68.5	227,416		0.0000	1.0000	97.63
69.5	80,938	1,082	0.0134	0.9866	97.63
70.5	76,597		0.0000	1.0000	96.33
71.5	80,505		0.0000	1.0000	96.33
72.5	80,505		0.0000	1.0000	96.33
73.5	79,825		0.0000	1.0000	96.33
74.5	84,673		0.0000	1.0000	96.33
75.5	84,673		0.0000	1.0000	96.33
76.5	84,628		0.0000	1.0000	96.33
77.5	84,585		0.0000	1.0000	96.33
78.5	81,679		0.0000	1.0000	96.33

PLACEMENT BAND 1901-2017 EXPERIENCE BAND 1947-2018

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	81,679		0.0000	1.0000	96.33
80.5	76,638		0.0000	1.0000	96.33
81.5	76,638		0.0000	1.0000	96.33
82.5	76,799		0.0000	1.0000	96.33
83.5	76,799		0.0000	1.0000	96.33
84.5	76,799		0.0000	1.0000	96.33
85.5	76,799		0.0000	1.0000	96.33
86.5	16,767		0.0000	1.0000	96.33
87.5	16,606		0.0000	1.0000	96.33
88.5	16,606		0.0000	1.0000	96.33
89.5	16,606		0.0000	1.0000	96.33
90.5	16,606		0.0000	1.0000	96.33
91.5	16,606		0.0000	1.0000	96.33
92.5					96.33

PLACEMENT BAND 1901-2017 EXPERIENCE BAND 1979-2018

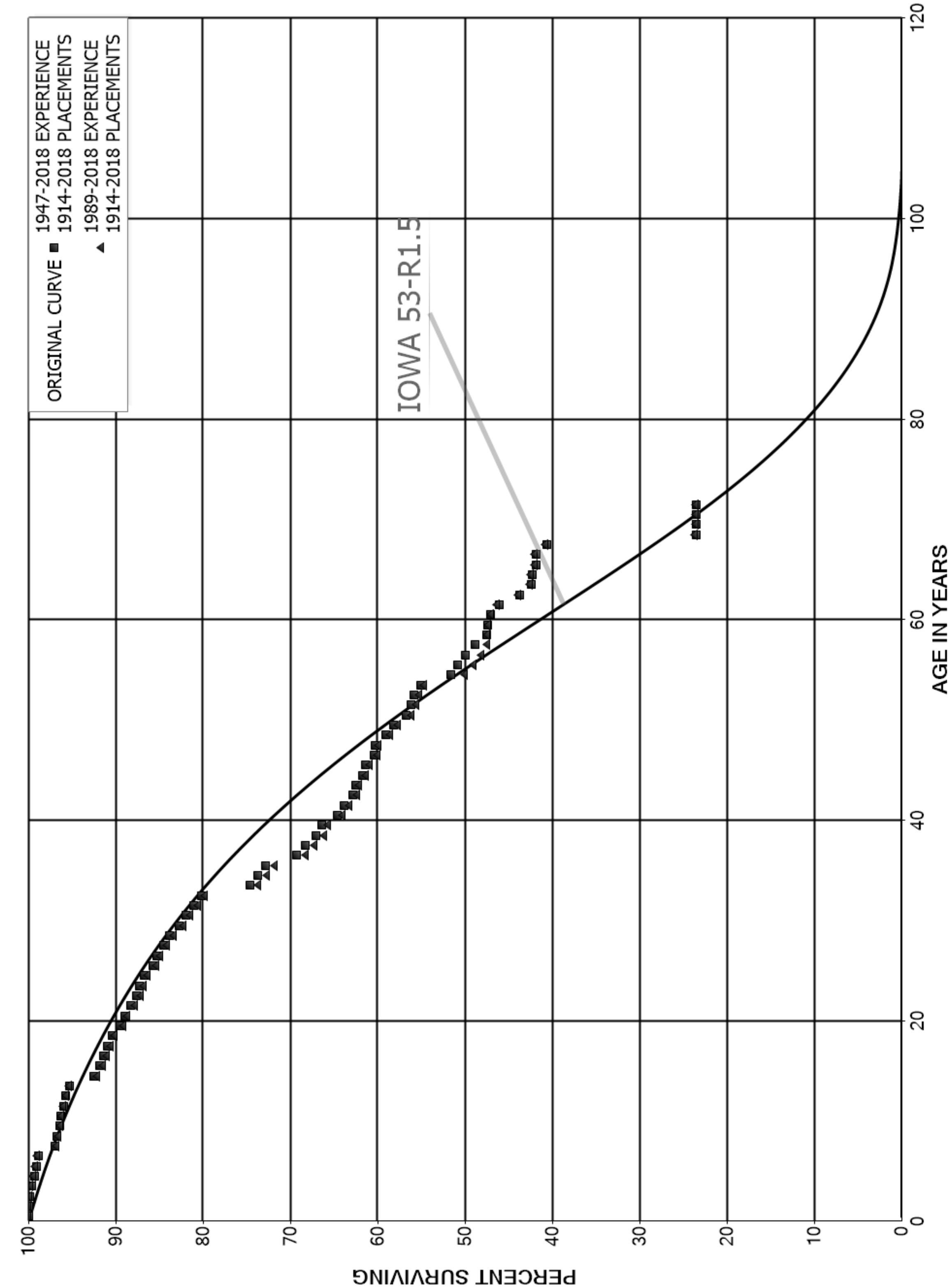
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	16,693,988	0	0.0000	1.0000	100.00
0.5	17,010,576	0	0.0000	1.0000	100.00
1.5	17,291,011	1,637	0.0001	0.9999	100.00
2.5	18,420,748	1	0.0000	1.0000	99.99
3.5	16,134,410	2,560	0.0002	0.9998	99.99
4.5	15,531,384	144	0.0000	1.0000	99.97
5.5	16,177,071	1,916	0.0001	0.9999	99.97
6.5	16,801,089	5,973	0.0004	0.9996	99.96
7.5	17,031,540	578	0.0000	1.0000	99.93
8.5	18,026,105	7,441	0.0004	0.9996	99.92
9.5	17,951,720	3,138	0.0002	0.9998	99.88
10.5	17,371,667	697	0.0000	1.0000	99.86
11.5	17,692,699	1,470	0.0001	0.9999	99.86
12.5	16,555,197	10,065	0.0006	0.9994	99.85
13.5	16,227,178	2,752	0.0002	0.9998	99.79
14.5	16,507,499	1,298	0.0001	0.9999	99.77
15.5	17,043,284	288	0.0000	1.0000	99.77
16.5	17,135,743	144	0.0000	1.0000	99.76
17.5	17,125,760	13,343	0.0008	0.9992	99.76
18.5	17,277,630	8,190	0.0005	0.9995	99.69
19.5	17,376,762	3,062	0.0002	0.9998	99.64
20.5	17,646,103	456	0.0000	1.0000	99.62
21.5	17,733,948	306	0.0000	1.0000	99.62
22.5	17,274,992	4,421	0.0003	0.9997	99.62
23.5	16,404,229	2,408	0.0001	0.9999	99.59
24.5	15,680,327	5,843	0.0004	0.9996	99.58
25.5	16,002,034	2,696	0.0002	0.9998	99.54
26.5	14,354,112	16,299	0.0011	0.9989	99.52
27.5	13,920,349	1,794	0.0001	0.9999	99.41
28.5	13,350,330	1,452	0.0001	0.9999	99.40
29.5	12,133,446	8,144	0.0007	0.9993	99.39
30.5	10,266,362	3,023	0.0003	0.9997	99.32
31.5	8,449,958	1,131	0.0001	0.9999	99.29
32.5	8,061,360	3,834	0.0005	0.9995	99.28
33.5	7,894,852	2,910	0.0004	0.9996	99.23
34.5	7,760,047	2,402	0.0003	0.9997	99.19
35.5	7,742,951	1,978	0.0003	0.9997	99.16
36.5	7,037,840	13,264	0.0019	0.9981	99.14
37.5	6,519,229	1,315	0.0002	0.9998	98.95
38.5	6,525,648	635	0.0001	0.9999	98.93

PLACEMENT BAND 1901-2017 EXPERIENCE BAND 1979-2018

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	6,303,914	812	0.0001	0.9999	98.92
40.5	6,223,109	817	0.0001	0.9999	98.91
41.5	5,593,344	1,691	0.0003	0.9997	98.90
42.5	5,495,642	1,141	0.0002	0.9998	98.87
43.5	5,051,770	5,484	0.0011	0.9989	98.84
44.5	4,768,329	1,935	0.0004	0.9996	98.74
45.5	4,548,866	1,354	0.0003	0.9997	98.70
46.5	4,090,479	2,558	0.0006	0.9994	98.67
47.5	3,806,650	158	0.0000	1.0000	98.61
48.5	3,426,411	5,113	0.0015	0.9985	98.60
49.5	2,848,395	206	0.0001	0.9999	98.46
50.5	2,742,901	2,328	0.0008	0.9992	98.45
51.5	2,285,374	87	0.0000	1.0000	98.36
52.5	1,864,994	95	0.0001	0.9999	98.36
53.5	1,540,402	135	0.0001	0.9999	98.36
54.5	1,290,133	12	0.0000	1.0000	98.35
55.5	821,003	368	0.0004	0.9996	98.35
56.5	709,608	1	0.0000	1.0000	98.30
57.5	627,054	6	0.0000	1.0000	98.30
58.5	597,354	2,126	0.0036	0.9964	98.30
59.5	466,060	112	0.0002	0.9998	97.95
60.5	384,635	25	0.0001	0.9999	97.93
61.5	368,538	6	0.0000	1.0000	97.92
62.5	322,702	1	0.0000	1.0000	97.92
63.5	317,124		0.0000	1.0000	97.92
64.5	188,777		0.0000	1.0000	97.92
65.5	154,954		0.0000	1.0000	97.92
66.5	158,935		0.0000	1.0000	97.92
67.5	249,094		0.0000	1.0000	97.92
68.5	227,416		0.0000	1.0000	97.92
69.5	80,938	1,082	0.0134	0.9866	97.92
70.5	76,597		0.0000	1.0000	96.61
71.5	80,505		0.0000	1.0000	96.61
72.5	80,505		0.0000	1.0000	96.61
73.5	79,825		0.0000	1.0000	96.61
74.5	84,673		0.0000	1.0000	96.61
75.5	84,673		0.0000	1.0000	96.61
76.5	84,628		0.0000	1.0000	96.61
77.5	84,585		0.0000	1.0000	96.61
78.5	81,679		0.0000	1.0000	96.61

PLACEMENT BAND 1901-2017 EXPERIENCE BAND 1979-2018

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	81,679		0.0000	1.0000	96.61
80.5	76,638		0.0000	1.0000	96.61
81.5	76,638		0.0000	1.0000	96.61
82.5	76,799		0.0000	1.0000	96.61
83.5	76,799		0.0000	1.0000	96.61
84.5	76,799		0.0000	1.0000	96.61
85.5	76,799		0.0000	1.0000	96.61
86.5	16,767		0.0000	1.0000	96.61
87.5	16,606		0.0000	1.0000	96.61
88.5	16,606		0.0000	1.0000	96.61
89.5	16,606		0.0000	1.0000	96.61
90.5	16,606		0.0000	1.0000	96.61
91.5	16,606		0.0000	1.0000	96.61
92.5					96.61


ORIGINAL CURVE
■ 1947-2018 EXPERIENCE
1914-2018 PLACEMENTS
▲ 1989-2018 EXPERIENCE
1914-2018 PLACEMENTS
IOWA 53-R1.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
120

PLACEMENT BAND 1914-2018 EXPERIENCE BAND 1947-2018

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	842,567,383	245,471	0.0003	0.9997	100.00
0.5	805,702,411	605,908	0.0008	0.9992	99.97
1.5	757,720,272	539,642	0.0007	0.9993	99.90
2.5	669,695,915	1,055,826	0.0016	0.9984	99.82
3.5	649,019,843	2,302,818	0.0035	0.9965	99.67
4.5	592,649,830	1,320,014	0.0022	0.9978	99.31
5.5	581,907,691	1,586,662	0.0027	0.9973	99.09
6.5	553,965,865	10,550,750	0.0190	0.9810	98.82
7.5	515,914,577	1,365,792	0.0026	0.9974	96.94
8.5	502,785,713	1,317,423	0.0026	0.9974	96.68
9.5	475,749,823	864,321	0.0018	0.9982	96.43
10.5	445,398,135	1,220,486	0.0027	0.9973	96.25
11.5	426,266,167	1,322,543	0.0031	0.9969	95.99
12.5	398,193,274	1,918,488	0.0048	0.9952	95.69
13.5	364,448,576	10,385,727	0.0285	0.9715	95.23
14.5	348,691,386	2,385,328	0.0068	0.9932	92.52
15.5	344,726,081	1,706,883	0.0050	0.9950	91.89
16.5	322,159,042	1,692,840	0.0053	0.9947	91.43
17.5	299,592,840	1,738,845	0.0058	0.9942	90.95
18.5	284,873,243	3,019,608	0.0106	0.9894	90.42
19.5	279,683,024	1,485,234	0.0053	0.9947	89.46
20.5	258,282,746	2,136,035	0.0083	0.9917	88.99
21.5	255,338,873	1,900,083	0.0074	0.9926	88.25
22.5	247,093,884	919,958	0.0037	0.9963	87.60
23.5	233,729,745	1,501,218	0.0064	0.9936	87.27
24.5	211,262,804	2,384,701	0.0113	0.9887	86.71
25.5	200,350,000	1,047,438	0.0052	0.9948	85.73
26.5	163,075,383	1,434,069	0.0088	0.9912	85.28
27.5	152,974,018	1,280,750	0.0084	0.9916	84.53
28.5	142,217,257	1,849,684	0.0130	0.9870	83.82
29.5	129,568,836	1,279,764	0.0099	0.9901	82.73
30.5	117,151,152	1,281,358	0.0109	0.9891	81.92
31.5	105,513,179	1,105,500	0.0105	0.9895	81.02
32.5	97,018,588	6,713,705	0.0692	0.9308	80.17
33.5	85,772,250	1,091,447	0.0127	0.9873	74.62
34.5	77,995,784	904,176	0.0116	0.9884	73.67
35.5	75,553,681	3,622,746	0.0479	0.9521	72.82
36.5	65,691,341	1,040,992	0.0158	0.9842	69.33
37.5	53,549,022	940,315	0.0176	0.9824	68.23
38.5	48,510,747	492,786	0.0102	0.9898	67.03

PLACEMENT BAND 1914-2018 EXPERIENCE BAND 1947-2018

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	42,796,332	1,087,388	0.0254	0.9746	66.35
40.5	48,750,685	633,499	0.0130	0.9870	64.67
41.5	41,418,372	621,043	0.0150	0.9850	63.83
42.5	38,335,269	238,875	0.0062	0.9938	62.87
43.5	28,263,344	357,751	0.0127	0.9873	62.48
44.5	24,262,177	126,973	0.0052	0.9948	61.69
45.5	20,608,625	316,943	0.0154	0.9846	61.36
46.5	18,991,085	58,466	0.0031	0.9969	60.42
47.5	16,936,028	342,422	0.0202	0.9798	60.23
48.5	14,143,258	210,611	0.0149	0.9851	59.02
49.5	12,287,473	296,957	0.0242	0.9758	58.14
50.5	10,974,885	111,636	0.0102	0.9898	56.73
51.5	8,344,191	42,517	0.0051	0.9949	56.15
52.5	7,002,716	94,845	0.0135	0.9865	55.87
53.5	6,107,237	385,689	0.0632	0.9368	55.11
54.5	5,485,158	88,262	0.0161	0.9839	51.63
55.5	5,148,072	86,870	0.0169	0.9831	50.80
56.5	4,545,378	100,440	0.0221	0.9779	49.94
57.5	4,216,296	115,419	0.0274	0.9726	48.84
58.5	4,022,422	12,396	0.0031	0.9969	47.50
59.5	3,546,140	20,492	0.0058	0.9942	47.36
60.5	3,474,697	75,313	0.0217	0.9783	47.08
61.5	3,354,189	169,393	0.0505	0.9495	46.06
62.5	3,180,376	101,072	0.0318	0.9682	43.74
63.5	2,502,958	2,246	0.0009	0.9991	42.35
64.5	2,494,490	25,303	0.0101	0.9899	42.31
65.5	2,440,877	1,049	0.0004	0.9996	41.88
66.5	2,430,795	69,397	0.0285	0.9715	41.86
67.5	2,250,605	949,558	0.4219	0.5781	40.67
68.5	1,206,691	2,445	0.0020	0.9980	23.51
69.5	577,259	148	0.0003	0.9997	23.46
70.5	570,572	6	0.0000	1.0000	23.45
71.5	544,875	50	0.0001	0.9999	23.45
72.5	542,382	331	0.0006	0.9994	23.45
73.5	416,560	601	0.0014	0.9986	23.44
74.5	417,388	3,312	0.0079	0.9921	23.40
75.5	407,947		0.0000	1.0000	23.22
76.5	407,442		0.0000	1.0000	23.22
77.5	407,442	1,100	0.0027	0.9973	23.22
78.5	406,307	19,219	0.0473	0.9527	23.16

PLACEMENT BAND 1914-2018 EXPERIENCE BAND 1947-2018

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	462,168	2,246	0.0049	0.9951	22.06
80.5	458,460		0.0000	1.0000	21.95
81.5	458,460		0.0000	1.0000	21.95
82.5	461,602	2,582	0.0056	0.9944	21.95
83.5	453,312	159	0.0003	0.9997	21.83
84.5	453,153	16	0.0000	1.0000	21.82
85.5	453,115		0.0000	1.0000	21.82
86.5	431,754	3,429	0.0079	0.9921	21.82
87.5	396,100		0.0000	1.0000	21.65
88.5	41,970		0.0000	1.0000	21.65
89.5	42,044		0.0000	1.0000	21.65
90.5	41,982		0.0000	1.0000	21.65
91.5	41,982		0.0000	1.0000	21.65
92.5					21.65
93.5	164		0.0000		
94.5	164		0.0000		
95.5	254		0.0000		
96.5	91		0.0000		
97.5	91		0.0000		
98.5					

PLACEMENT BAND 1914-2018 EXPERIENCE BAND 1989-2018

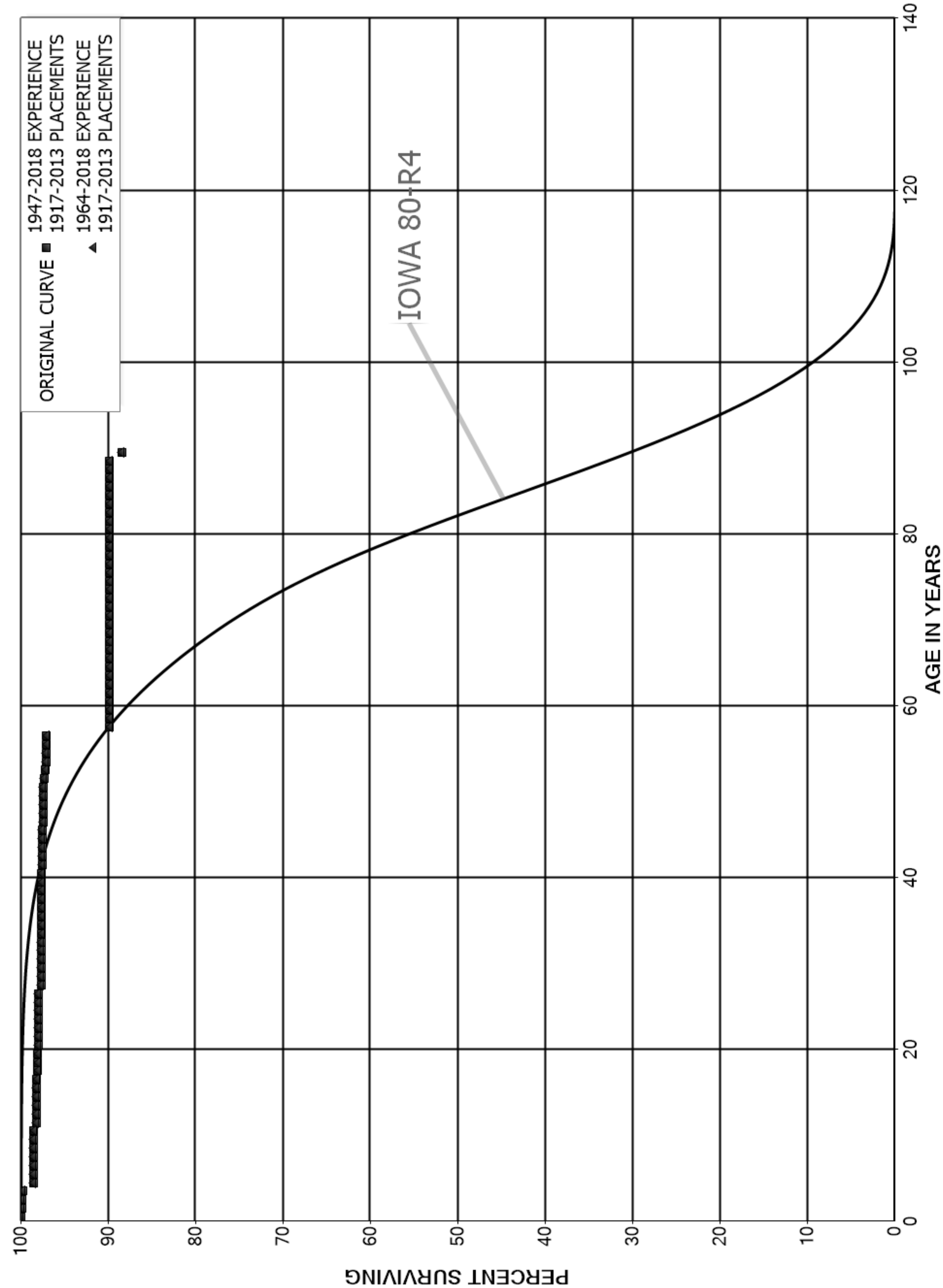
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	698,418,730	155,530	0.0002	0.9998	100.00
0.5	665,750,037	565,717	0.0008	0.9992	99.98
1.5	624,557,540	429,026	0.0007	0.9993	99.89
2.5	536,781,124	679,457	0.0013	0.9987	99.82
3.5	523,696,833	1,538,334	0.0029	0.9971	99.70
4.5	473,352,000	908,060	0.0019	0.9981	99.40
5.5	461,887,790	1,201,858	0.0026	0.9974	99.21
6.5	438,887,875	10,079,847	0.0230	0.9770	98.96
7.5	415,908,039	837,085	0.0020	0.9980	96.68
8.5	407,274,407	710,865	0.0017	0.9983	96.49
9.5	388,075,274	542,885	0.0014	0.9986	96.32
10.5	360,621,566	1,010,561	0.0028	0.9972	96.19
11.5	349,535,108	915,208	0.0026	0.9974	95.92
12.5	324,229,648	1,210,877	0.0037	0.9963	95.66
13.5	299,949,399	10,045,278	0.0335	0.9665	95.31
14.5	288,286,584	2,155,913	0.0075	0.9925	92.12
15.5	286,600,789	1,322,482	0.0046	0.9954	91.43
16.5	269,955,909	1,515,049	0.0056	0.9944	91.01
17.5	250,293,946	1,299,733	0.0052	0.9948	90.49
18.5	240,288,523	2,575,919	0.0107	0.9893	90.02
19.5	239,682,965	1,238,841	0.0052	0.9948	89.06
20.5	220,511,076	2,044,959	0.0093	0.9907	88.60
21.5	223,891,525	1,834,709	0.0082	0.9918	87.78
22.5	219,262,469	811,079	0.0037	0.9963	87.06
23.5	209,300,296	1,090,135	0.0052	0.9948	86.74
24.5	188,846,272	2,166,043	0.0115	0.9885	86.28
25.5	180,050,801	952,646	0.0053	0.9947	85.29
26.5	144,481,175	1,376,325	0.0095	0.9905	84.84
27.5	136,751,494	1,160,115	0.0085	0.9915	84.04
28.5	126,410,543	1,738,086	0.0137	0.9863	83.32
29.5	114,465,769	1,027,218	0.0090	0.9910	82.18
30.5	104,232,595	1,129,831	0.0108	0.9892	81.44
31.5	93,437,167	1,014,571	0.0109	0.9891	80.56
32.5	86,720,152	6,601,408	0.0761	0.9239	79.68
33.5	77,499,030	1,065,564	0.0137	0.9863	73.62
34.5	71,755,996	837,438	0.0117	0.9883	72.60
35.5	70,242,780	3,541,847	0.0504	0.9496	71.76
36.5	60,459,385	811,276	0.0134	0.9866	68.14
37.5	48,679,364	819,271	0.0168	0.9832	67.22
38.5	44,017,185	339,853	0.0077	0.9923	66.09

PLACEMENT BAND 1914-2018 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	39,999,895	993,355	0.0248	0.9752	65.58
40.5	46,152,847	581,638	0.0126	0.9874	63.95
41.5	38,917,840	528,122	0.0136	0.9864	63.15
42.5	35,938,420	141,124	0.0039	0.9961	62.29
43.5	25,987,830	340,920	0.0131	0.9869	62.05
44.5	22,061,082	123,851	0.0056	0.9944	61.23
45.5	18,643,242	271,904	0.0146	0.9854	60.89
46.5	17,122,492	39,909	0.0023	0.9977	60.00
47.5	15,130,057	337,188	0.0223	0.9777	59.86
48.5	12,410,542	192,616	0.0155	0.9845	58.53
49.5	10,586,906	294,825	0.0278	0.9722	57.62
50.5	9,281,741	82,557	0.0089	0.9911	56.01
51.5	6,674,041	41,834	0.0063	0.9937	55.52
52.5	5,336,447	48,460	0.0091	0.9909	55.17
53.5	4,499,419	384,712	0.0855	0.9145	54.67
54.5	3,878,331	84,086	0.0217	0.9783	49.99
55.5	3,539,575	64,451	0.0182	0.9818	48.91
56.5	2,966,342	35,662	0.0120	0.9880	48.02
57.5	2,731,873	3,170	0.0012	0.9988	47.44
58.5	3,834,085	12,396	0.0032	0.9968	47.39
59.5	3,364,649	16,924	0.0050	0.9950	47.23
60.5	3,300,410	48,690	0.0148	0.9852	46.99
61.5	3,208,936	169,393	0.0528	0.9472	46.30
62.5	3,174,105	101,072	0.0318	0.9682	43.86
63.5	2,496,730	2,246	0.0009	0.9991	42.46
64.5	2,494,408	25,303	0.0101	0.9899	42.42
65.5	2,440,839	1,049	0.0004	0.9996	41.99
66.5	2,430,757	69,397	0.0285	0.9715	41.97
67.5	2,250,567	949,558	0.4219	0.5781	40.78
68.5	1,206,653	2,445	0.0020	0.9980	23.57
69.5	577,221	148	0.0003	0.9997	23.52
70.5	570,534	6	0.0000	1.0000	23.52
71.5	544,837	50	0.0001	0.9999	23.52
72.5	542,344	331	0.0006	0.9994	23.52
73.5	416,521	601	0.0014	0.9986	23.50
74.5	417,388	3,312	0.0079	0.9921	23.47
75.5	407,947		0.0000	1.0000	23.28
76.5	407,442		0.0000	1.0000	23.28
77.5	407,442	1,100	0.0027	0.9973	23.28
78.5	406,307	19,219	0.0473	0.9527	23.22

PLACEMENT BAND 1914-2018 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	462,168	2,246	0.0049	0.9951	22.12
80.5	458,460		0.0000	1.0000	22.01
81.5	458,460		0.0000	1.0000	22.01
82.5	461,602	2,582	0.0056	0.9944	22.01
83.5	453,312	159	0.0003	0.9997	21.89
84.5	453,153	16	0.0000	1.0000	21.88
85.5	453,115		0.0000	1.0000	21.88
86.5	431,754	3,429	0.0079	0.9921	21.88
87.5	396,100		0.0000	1.0000	21.71
88.5	41,970		0.0000	1.0000	21.71
89.5	42,044		0.0000	1.0000	21.71
90.5	41,982		0.0000	1.0000	21.71
91.5	41,982		0.0000	1.0000	21.71
92.5					21.71
93.5	164		0.0000		
94.5	164		0.0000		
95.5	254		0.0000		
96.5	91		0.0000		
97.5	91		0.0000		
98.5					


ORIGINAL CURVE ■ 1947-2018 EXPERIENCE
1917-2013 PLACEMENTS
▲ 1964-2018 EXPERIENCE
1917-2013 PLACEMENTS
IOWA 80-R4
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120
140

PLACEMENT BAND 1917-2013 EXPERIENCE BAND 1947-2018

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	34,168,659		0.0000	1.0000	100.00
0.5	34,809,738	55,183	0.0016	0.9984	100.00
1.5	35,531,295		0.0000	1.0000	99.84
2.5	34,739,851	25,009	0.0007	0.9993	99.84
3.5	34,668,857	423,035	0.0122	0.9878	99.77
4.5	35,109,905	6,895	0.0002	0.9998	98.55
5.5	34,990,601	8,148	0.0002	0.9998	98.53
6.5	35,014,611	1,241	0.0000	1.0000	98.51
7.5	35,018,023		0.0000	1.0000	98.51
8.5	35,023,491		0.0000	1.0000	98.51
9.5	35,004,935	10,981	0.0003	0.9997	98.51
10.5	35,103,006	91,991	0.0026	0.9974	98.48
11.5	35,011,014	436	0.0000	1.0000	98.22
12.5	35,028,706	9,012	0.0003	0.9997	98.22
13.5	35,700,250		0.0000	1.0000	98.19
14.5	35,700,250	220	0.0000	1.0000	98.19
15.5	35,894,862	14,139	0.0004	0.9996	98.19
16.5	35,965,121	47,079	0.0013	0.9987	98.15
17.5	35,349,722	375	0.0000	1.0000	98.02
18.5	35,301,381		0.0000	1.0000	98.02
19.5	35,373,352	12,231	0.0003	0.9997	98.02
20.5	35,447,129		0.0000	1.0000	97.99
21.5	35,443,289		0.0000	1.0000	97.99
22.5	35,443,289		0.0000	1.0000	97.99
23.5	35,443,289		0.0000	1.0000	97.99
24.5	35,465,726		0.0000	1.0000	97.99
25.5	35,407,171		0.0000	1.0000	97.99
26.5	35,407,141	124,318	0.0035	0.9965	97.99
27.5	35,251,781		0.0000	1.0000	97.64
28.5	35,279,587		0.0000	1.0000	97.64
29.5	35,279,587		0.0000	1.0000	97.64
30.5	32,590,150	226	0.0000	1.0000	97.64
31.5	32,620,967		0.0000	1.0000	97.64
32.5	32,620,967	19,316	0.0006	0.9994	97.64
33.5	26,784,076		0.0000	1.0000	97.59
34.5	26,957,859		0.0000	1.0000	97.59
35.5	28,897,060		0.0000	1.0000	97.59
36.5	27,318,806		0.0000	1.0000	97.59
37.5	25,928,053		0.0000	1.0000	97.59
38.5	23,828,895		0.0000	1.0000	97.59

PLACEMENT BAND 1917-2013 EXPERIENCE BAND 1947-2018

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	23,807,242		0.0000	1.0000	97.59
40.5	23,624,297	7,340	0.0003	0.9997	97.59
41.5	23,637,322	10,573	0.0004	0.9996	97.56
42.5	23,727,199		0.0000	1.0000	97.51
43.5	23,481,284		0.0000	1.0000	97.51
44.5	23,444,465		0.0000	1.0000	97.51
45.5	23,035,370	17,215	0.0007	0.9993	97.51
46.5	22,391,483		0.0000	1.0000	97.44
47.5	21,517,534		0.0000	1.0000	97.44
48.5	19,432,419		0.0000	1.0000	97.44
49.5	16,271,414		0.0000	1.0000	97.44
50.5	14,593,135	16,256	0.0011	0.9989	97.44
51.5	12,374,052	25,850	0.0021	0.9979	97.33
52.5	13,433,290	1,111	0.0001	0.9999	97.13
53.5	11,391,326		0.0000	1.0000	97.12
54.5	9,328,045	9,164	0.0010	0.9990	97.12
55.5	7,800,685		0.0000	1.0000	97.02
56.5	4,785,055	355,719	0.0743	0.9257	97.02
57.5	2,107,852		0.0000	1.0000	89.81
58.5	1,527,885		0.0000	1.0000	89.81
59.5	1,527,885		0.0000	1.0000	89.81
60.5	1,527,885		0.0000	1.0000	89.81
61.5	1,131,639		0.0000	1.0000	89.81
62.5	1,096,886		0.0000	1.0000	89.81
63.5	1,096,886		0.0000	1.0000	89.81
64.5	1,025,060		0.0000	1.0000	89.81
65.5	1,017,932		0.0000	1.0000	89.81
66.5	1,017,932		0.0000	1.0000	89.81
67.5	1,017,932		0.0000	1.0000	89.81
68.5	1,017,932		0.0000	1.0000	89.81
69.5	995,606		0.0000	1.0000	89.81
70.5	983,508		0.0000	1.0000	89.81
71.5	966,981		0.0000	1.0000	89.81
72.5	966,366		0.0000	1.0000	89.81
73.5	936,020		0.0000	1.0000	89.81
74.5	934,750		0.0000	1.0000	89.81
75.5	932,577		0.0000	1.0000	89.81
76.5	924,696		0.0000	1.0000	89.81
77.5	917,810		0.0000	1.0000	89.81
78.5	832,224		0.0000	1.0000	89.81

PLACEMENT BAND 1917-2013 EXPERIENCE BAND 1947-2018

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	831,817		0.0000	1.0000	89.81
80.5	831,658		0.0000	1.0000	89.81
81.5	831,658		0.0000	1.0000	89.81
82.5	831,658		0.0000	1.0000	89.81
83.5	831,658		0.0000	1.0000	89.81
84.5	831,658		0.0000	1.0000	89.81
85.5	831,474		0.0000	1.0000	89.81
86.5	555,611		0.0000	1.0000	89.81
87.5	218,170		0.0000	1.0000	89.81
88.5	206,861	3,281	0.0159	0.9841	89.81
89.5	157,661		0.0000	1.0000	88.39
90.5	138,380		0.0000	1.0000	88.39
91.5	107,929		0.0000	1.0000	88.39
92.5	8,523		0.0000	1.0000	88.39
93.5	8,523		0.0000	1.0000	88.39
94.5	7,972		0.0000	1.0000	88.39
95.5	3,480		0.0000	1.0000	88.39
96.5	1,788		0.0000	1.0000	88.39
97.5	1,788		0.0000	1.0000	88.39
98.5	1,788		0.0000	1.0000	88.39
99.5	1,788		0.0000	1.0000	88.39
100.5	1,788		0.0000	1.0000	88.39
101.5					88.39

PLACEMENT BAND 1917-2013 EXPERIENCE BAND 1964-2018

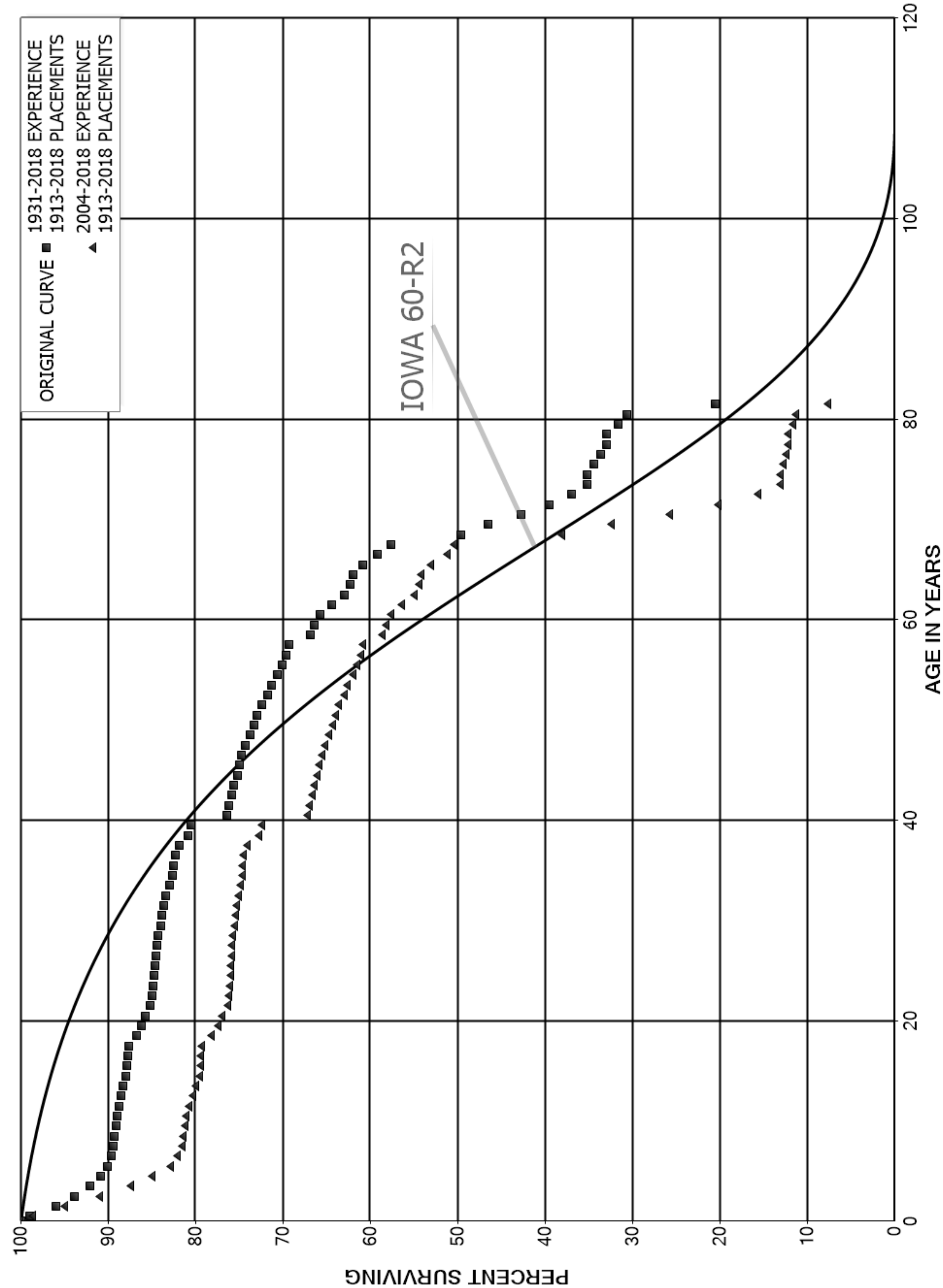
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	28,088,221		0.0000	1.0000	100.00
0.5	28,730,433	54,787	0.0019	0.9981	100.00
1.5	32,482,367		0.0000	1.0000	99.81
2.5	33,501,764	25,009	0.0007	0.9993	99.81
3.5	33,948,280	423,035	0.0125	0.9875	99.73
4.5	34,389,328	6,895	0.0002	0.9998	98.49
5.5	34,625,743	8,148	0.0002	0.9998	98.47
6.5	34,983,116	1,241	0.0000	1.0000	98.45
7.5	34,986,529		0.0000	1.0000	98.45
8.5	34,991,996		0.0000	1.0000	98.45
9.5	35,004,935	10,981	0.0003	0.9997	98.45
10.5	35,103,006	91,991	0.0026	0.9974	98.41
11.5	35,011,014	436	0.0000	1.0000	98.16
12.5	35,028,706	9,012	0.0003	0.9997	98.16
13.5	35,700,250		0.0000	1.0000	98.13
14.5	35,700,250	220	0.0000	1.0000	98.13
15.5	35,714,142	14,139	0.0004	0.9996	98.13
16.5	35,777,425	47,079	0.0013	0.9987	98.09
17.5	35,162,025	375	0.0000	1.0000	97.96
18.5	35,113,685		0.0000	1.0000	97.96
19.5	35,185,655	12,231	0.0003	0.9997	97.96
20.5	35,178,063		0.0000	1.0000	97.93
21.5	35,174,224		0.0000	1.0000	97.93
22.5	35,181,200		0.0000	1.0000	97.93
23.5	35,181,200		0.0000	1.0000	97.93
24.5	35,203,637		0.0000	1.0000	97.93
25.5	35,145,083		0.0000	1.0000	97.93
26.5	35,145,052	124,318	0.0035	0.9965	97.93
27.5	34,989,693		0.0000	1.0000	97.58
28.5	35,017,498		0.0000	1.0000	97.58
29.5	35,017,498		0.0000	1.0000	97.58
30.5	32,328,062	226	0.0000	1.0000	97.58
31.5	32,358,878		0.0000	1.0000	97.58
32.5	32,620,967	19,316	0.0006	0.9994	97.58
33.5	26,784,076		0.0000	1.0000	97.52
34.5	26,957,859		0.0000	1.0000	97.52
35.5	28,897,060		0.0000	1.0000	97.52
36.5	27,318,806		0.0000	1.0000	97.52
37.5	25,928,053		0.0000	1.0000	97.52
38.5	23,828,895		0.0000	1.0000	97.52

PLACEMENT BAND 1917-2013 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	23,807,242		0.0000	1.0000	97.52
40.5	23,624,297	7,340	0.0003	0.9997	97.52
41.5	23,637,322	10,573	0.0004	0.9996	97.49
42.5	23,727,199		0.0000	1.0000	97.45
43.5	23,481,284		0.0000	1.0000	97.45
44.5	23,444,465		0.0000	1.0000	97.45
45.5	23,035,370	17,215	0.0007	0.9993	97.45
46.5	22,391,483		0.0000	1.0000	97.38
47.5	21,517,534		0.0000	1.0000	97.38
48.5	19,432,419		0.0000	1.0000	97.38
49.5	16,271,414		0.0000	1.0000	97.38
50.5	14,593,135	16,256	0.0011	0.9989	97.38
51.5	12,374,052	25,850	0.0021	0.9979	97.27
52.5	13,433,290	1,111	0.0001	0.9999	97.06
53.5	11,391,326		0.0000	1.0000	97.06
54.5	9,328,045	9,164	0.0010	0.9990	97.06
55.5	7,800,685		0.0000	1.0000	96.96
56.5	4,785,055	355,719	0.0743	0.9257	96.96
57.5	2,107,852		0.0000	1.0000	89.75
58.5	1,527,885		0.0000	1.0000	89.75
59.5	1,527,885		0.0000	1.0000	89.75
60.5	1,527,885		0.0000	1.0000	89.75
61.5	1,131,639		0.0000	1.0000	89.75
62.5	1,096,886		0.0000	1.0000	89.75
63.5	1,096,886		0.0000	1.0000	89.75
64.5	1,025,060		0.0000	1.0000	89.75
65.5	1,017,932		0.0000	1.0000	89.75
66.5	1,017,932		0.0000	1.0000	89.75
67.5	1,017,932		0.0000	1.0000	89.75
68.5	1,017,932		0.0000	1.0000	89.75
69.5	995,606		0.0000	1.0000	89.75
70.5	983,508		0.0000	1.0000	89.75
71.5	966,981		0.0000	1.0000	89.75
72.5	966,366		0.0000	1.0000	89.75
73.5	936,020		0.0000	1.0000	89.75
74.5	934,750		0.0000	1.0000	89.75
75.5	932,577		0.0000	1.0000	89.75
76.5	924,696		0.0000	1.0000	89.75
77.5	917,810		0.0000	1.0000	89.75
78.5	832,224		0.0000	1.0000	89.75

PLACEMENT BAND 1917-2013 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	831,817		0.0000	1.0000	89.75
80.5	831,658		0.0000	1.0000	89.75
81.5	831,658		0.0000	1.0000	89.75
82.5	831,658		0.0000	1.0000	89.75
83.5	831,658		0.0000	1.0000	89.75
84.5	831,658		0.0000	1.0000	89.75
85.5	831,474		0.0000	1.0000	89.75
86.5	555,611		0.0000	1.0000	89.75
87.5	218,170		0.0000	1.0000	89.75
88.5	206,861	3,281	0.0159	0.9841	89.75
89.5	157,661		0.0000	1.0000	88.33
90.5	138,380		0.0000	1.0000	88.33
91.5	107,929		0.0000	1.0000	88.33
92.5	8,523		0.0000	1.0000	88.33
93.5	8,523		0.0000	1.0000	88.33
94.5	7,972		0.0000	1.0000	88.33
95.5	3,480		0.0000	1.0000	88.33
96.5	1,788		0.0000	1.0000	88.33
97.5	1,788		0.0000	1.0000	88.33
98.5	1,788		0.0000	1.0000	88.33
99.5	1,788		0.0000	1.0000	88.33
100.5	1,788		0.0000	1.0000	88.33
101.5					88.33


ORIGINAL CURVE ■ 1931-2018 EXPERIENCE
1913-2018 PLACEMENTS
▲ 2004-2018 EXPERIENCE
1913-2018 PLACEMENTS
IOWA 60-R2
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
20
40
60
80
100
120

PLACEMENT BAND 1913-2018 EXPERIENCE BAND 1931-2018

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	345,733,884	3,829,373	0.0111	0.9889	100.00
0.5	332,030,153	9,792,743	0.0295	0.9705	98.89
1.5	208,885,695	4,563,131	0.0218	0.9782	95.98
2.5	177,269,118	3,388,351	0.0191	0.9809	93.88
3.5	164,526,586	2,218,927	0.0135	0.9865	92.08
4.5	156,422,599	1,388,351	0.0089	0.9911	90.84
5.5	153,282,279	638,922	0.0042	0.9958	90.04
6.5	146,049,788	502,041	0.0034	0.9966	89.66
7.5	142,936,348	172,624	0.0012	0.9988	89.35
8.5	140,466,736	314,481	0.0022	0.9978	89.25
9.5	136,515,126	144,653	0.0011	0.9989	89.05
10.5	131,625,695	282,144	0.0021	0.9979	88.95
11.5	127,023,152	377,162	0.0030	0.9970	88.76
12.5	121,772,251	323,484	0.0027	0.9973	88.50
13.5	119,893,821	429,373	0.0036	0.9964	88.26
14.5	119,152,901	150,537	0.0013	0.9987	87.95
15.5	119,328,408	126,804	0.0011	0.9989	87.83
16.5	117,641,379	115,725	0.0010	0.9990	87.74
17.5	112,723,168	1,183,441	0.0105	0.9895	87.65
18.5	109,219,354	737,481	0.0068	0.9932	86.73
19.5	108,671,371	556,922	0.0051	0.9949	86.15
20.5	99,361,347	629,730	0.0063	0.9937	85.71
21.5	98,593,096	204,611	0.0021	0.9979	85.16
22.5	97,242,152	148,935	0.0015	0.9985	84.99
23.5	95,934,114	180,413	0.0019	0.9981	84.86
24.5	94,857,939	98,895	0.0010	0.9990	84.70
25.5	91,445,662	132,611	0.0015	0.9985	84.61
26.5	86,864,200	109,277	0.0013	0.9987	84.49
27.5	74,312,058	95,750	0.0013	0.9987	84.38
28.5	66,611,321	217,183	0.0033	0.9967	84.27
29.5	52,985,681	105,846	0.0020	0.9980	84.00
30.5	48,983,341	129,042	0.0026	0.9974	83.83
31.5	43,834,916	133,548	0.0030	0.9970	83.61
32.5	40,386,038	188,247	0.0047	0.9953	83.35
33.5	39,032,529	157,026	0.0040	0.9960	82.96
34.5	37,373,477	52,900	0.0014	0.9986	82.63
35.5	33,876,640	79,219	0.0023	0.9977	82.51
36.5	32,919,157	198,215	0.0060	0.9940	82.32
37.5	22,464,100	279,813	0.0125	0.9875	81.83
38.5	20,308,710	80,789	0.0040	0.9960	80.81

PLACEMENT BAND 1913-2018 EXPERIENCE BAND 1931-2018

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	18,955,202	968,880	0.0511	0.9489	80.48
40.5	17,546,179	56,273	0.0032	0.9968	76.37
41.5	16,695,158	74,478	0.0045	0.9955	76.13
42.5	15,183,749	42,271	0.0028	0.9972	75.79
43.5	14,479,680	68,090	0.0047	0.9953	75.58
44.5	13,788,515	51,695	0.0037	0.9963	75.22
45.5	13,088,341	42,229	0.0032	0.9968	74.94
46.5	12,658,903	69,915	0.0055	0.9945	74.70
47.5	11,780,770	87,264	0.0074	0.9926	74.28
48.5	11,004,988	65,251	0.0059	0.9941	73.73
49.5	9,844,016	53,325	0.0054	0.9946	73.30
50.5	8,790,013	58,833	0.0067	0.9933	72.90
51.5	8,028,257	75,793	0.0094	0.9906	72.41
52.5	7,280,815	43,585	0.0060	0.9940	71.73
53.5	6,385,822	59,228	0.0093	0.9907	71.30
54.5	5,827,582	46,185	0.0079	0.9921	70.64
55.5	5,176,613	31,225	0.0060	0.9940	70.08
56.5	4,614,593	26,589	0.0058	0.9942	69.65
57.5	4,232,607	146,808	0.0347	0.9653	69.25
58.5	3,651,560	27,437	0.0075	0.9925	66.85
59.5	3,027,573	26,179	0.0086	0.9914	66.35
60.5	2,440,644	50,445	0.0207	0.9793	65.78
61.5	1,619,596	35,359	0.0218	0.9782	64.42
62.5	1,323,956	14,983	0.0113	0.9887	63.01
63.5	1,074,384	5,980	0.0056	0.9944	62.30
64.5	915,979	17,271	0.0189	0.9811	61.95
65.5	354,527	9,448	0.0266	0.9734	60.78
66.5	311,746	7,957	0.0255	0.9745	59.16
67.5	257,398	36,075	0.1402	0.8598	57.65
68.5	187,866	11,695	0.0623	0.9377	49.57
69.5	176,171	14,308	0.0812	0.9188	46.49
70.5	161,851	11,951	0.0738	0.9262	42.71
71.5	149,892	10,000	0.0667	0.9333	39.56
72.5	139,819	6,675	0.0477	0.9523	36.92
73.5	133,144	63	0.0005	0.9995	35.16
74.5	133,074	2,679	0.0201	0.9799	35.14
75.5	130,382	2,973	0.0228	0.9772	34.43
76.5	127,406	2,419	0.0190	0.9810	33.65
77.5	117,831		0.0000	1.0000	33.01
78.5	108,439	4,571	0.0422	0.9578	33.01

PLACEMENT BAND 1913-2018 EXPERIENCE BAND 1931-2018

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	101,126	3,326	0.0329	0.9671	31.62
80.5	97,763	32,197	0.3293	0.6707	30.58
81.5	65,566	1,363	0.0208	0.9792	20.51
82.5	51,297		0.0000	1.0000	20.08
83.5	32,196	5,393	0.1675	0.8325	20.08
84.5	26,803	925	0.0345	0.9655	16.72
85.5	25,878	11,877	0.4589	0.5411	16.14
86.5	14,001	5,518	0.3941	0.6059	8.73
87.5	8,483	2,083	0.2455	0.7545	5.29
88.5	3,194	610	0.1908	0.8092	3.99
89.5	2,585	138	0.0533	0.9467	3.23
90.5	2,447		0.0000	1.0000	3.06
91.5	2,447		0.0000	1.0000	3.06
92.5	2,447	1,165	0.4762	0.5238	3.06
93.5	1,282	1,282	1.0000		1.60
94.5					

PLACEMENT BAND 1913-2018 EXPERIENCE BAND 2004-2018

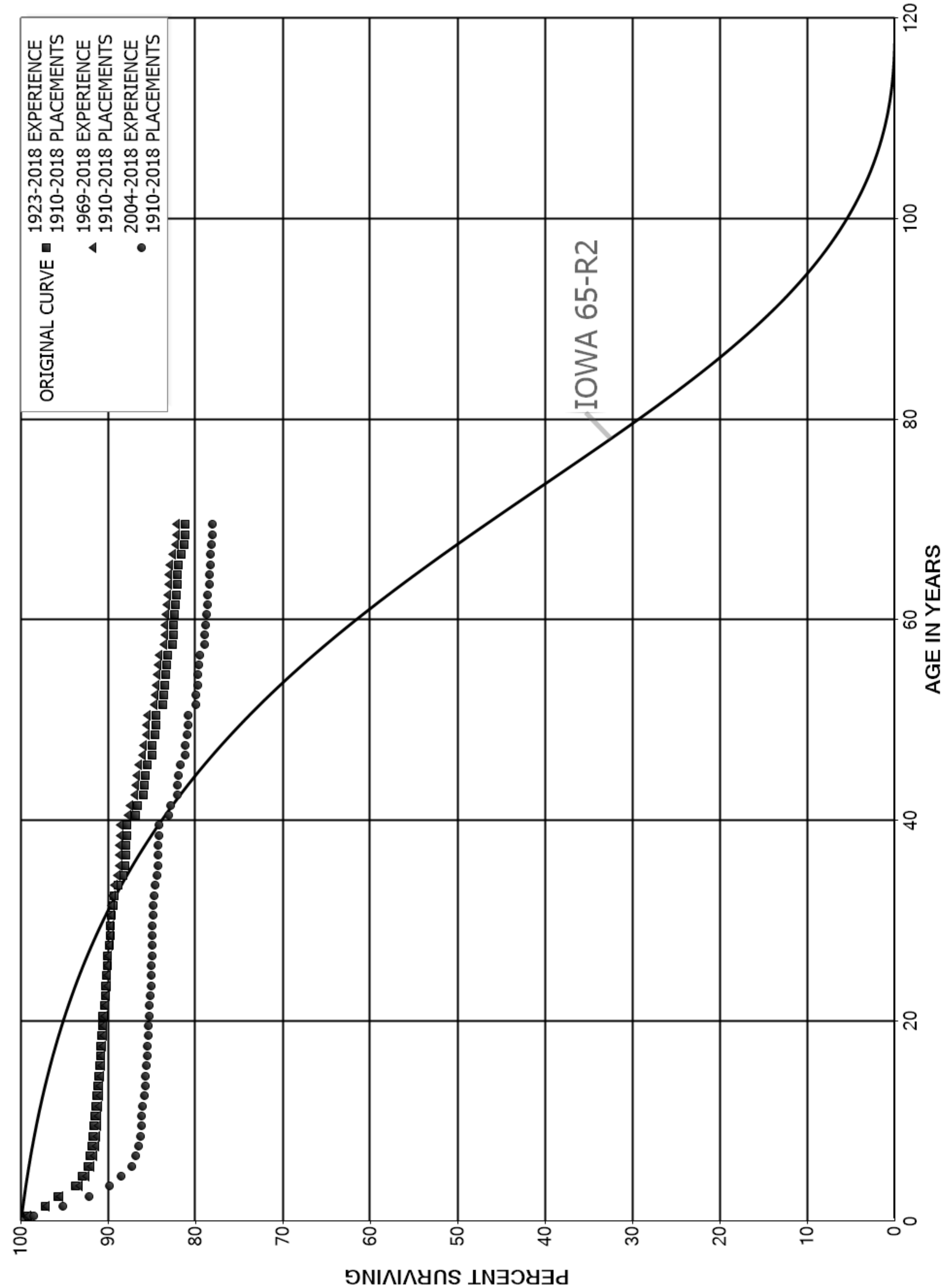
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	234,420,750	3,599,904	0.0154	0.9846	100.00
0.5	221,260,967	8,153,266	0.0368	0.9632	98.46
1.5	101,211,040	4,301,829	0.0425	0.9575	94.84
2.5	72,625,989	2,794,315	0.0385	0.9615	90.81
3.5	62,346,981	1,806,721	0.0290	0.9710	87.31
4.5	53,403,973	1,273,469	0.0238	0.9762	84.78
5.5	60,850,307	557,289	0.0092	0.9908	82.76
6.5	53,232,201	405,902	0.0076	0.9924	82.00
7.5	50,845,460	83,795	0.0016	0.9984	81.38
8.5	48,777,413	136,236	0.0028	0.9972	81.24
9.5	45,524,046	51,047	0.0011	0.9989	81.02
10.5	43,231,853	155,268	0.0036	0.9964	80.92
11.5	42,652,303	254,117	0.0060	0.9940	80.63
12.5	49,694,278	228,244	0.0046	0.9954	80.15
13.5	56,259,412	302,491	0.0054	0.9946	79.79
14.5	68,784,856	73,277	0.0011	0.9989	79.36
15.5	72,621,006	27,224	0.0004	0.9996	79.27
16.5	74,525,859	31,415	0.0004	0.9996	79.24
17.5	72,738,226	1,089,722	0.0150	0.9850	79.21
18.5	70,308,599	644,776	0.0092	0.9908	78.02
19.5	71,210,337	465,230	0.0065	0.9935	77.31
20.5	62,908,378	497,596	0.0079	0.9921	76.80
21.5	63,097,521	107,265	0.0017	0.9983	76.19
22.5	72,009,757	85,394	0.0012	0.9988	76.06
23.5	74,533,042	97,907	0.0013	0.9987	75.97
24.5	74,779,050	51,844	0.0007	0.9993	75.87
25.5	71,815,114	46,723	0.0007	0.9993	75.82
26.5	69,001,430	59,879	0.0009	0.9991	75.77
27.5	57,998,883	57,667	0.0010	0.9990	75.71
28.5	50,987,107	178,582	0.0035	0.9965	75.63
29.5	38,045,219	55,710	0.0015	0.9985	75.37
30.5	34,927,045	62,223	0.0018	0.9982	75.26
31.5	30,336,173	89,480	0.0029	0.9971	75.12
32.5	27,832,360	80,208	0.0029	0.9971	74.90
33.5	27,294,741	47,489	0.0017	0.9983	74.68
34.5	26,884,159	16,527	0.0006	0.9994	74.55
35.5	24,475,605	38,095	0.0016	0.9984	74.51
36.5	24,308,281	147,485	0.0061	0.9939	74.39
37.5	14,625,399	264,797	0.0181	0.9819	73.94
38.5	13,393,571	50,166	0.0037	0.9963	72.60

PLACEMENT BAND 1913-2018 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	12,605,447	921,379	0.0731	0.9269	72.33
40.5	11,896,807	43,577	0.0037	0.9963	67.04
41.5	11,654,684	55,389	0.0048	0.9952	66.80
42.5	10,556,346	37,532	0.0036	0.9964	66.48
43.5	10,327,134	49,984	0.0048	0.9952	66.24
44.5	10,304,550	37,840	0.0037	0.9963	65.92
45.5	10,262,358	37,489	0.0037	0.9963	65.68
46.5	10,671,237	54,947	0.0051	0.9949	65.44
47.5	10,104,160	73,948	0.0073	0.9927	65.10
48.5	9,602,732	59,968	0.0062	0.9938	64.63
49.5	8,614,493	46,397	0.0054	0.9946	64.22
50.5	8,176,592	52,294	0.0064	0.9936	63.88
51.5	7,452,283	75,124	0.0101	0.9899	63.47
52.5	6,880,141	40,362	0.0059	0.9941	62.83
53.5	6,051,951	57,356	0.0095	0.9905	62.46
54.5	5,541,798	45,072	0.0081	0.9919	61.87
55.5	4,933,837	29,956	0.0061	0.9939	61.37
56.5	4,386,598	20,053	0.0046	0.9954	60.99
57.5	4,017,080	146,189	0.0364	0.9636	60.72
58.5	3,459,427	26,166	0.0076	0.9924	58.51
59.5	2,839,622	25,807	0.0091	0.9909	58.06
60.5	2,257,932	50,194	0.0222	0.9778	57.54
61.5	1,446,574	35,296	0.0244	0.9756	56.26
62.5	1,173,654	12,416	0.0106	0.9894	54.88
63.5	937,084	4,930	0.0053	0.9947	54.30
64.5	788,188	15,485	0.0196	0.9804	54.02
65.5	230,201	8,023	0.0349	0.9651	52.96
66.5	192,625	3,126	0.0162	0.9838	51.11
67.5	146,731	35,925	0.2448	0.7552	50.28
68.5	78,116	11,695	0.1497	0.8503	37.97
69.5	68,749	14,308	0.2081	0.7919	32.29
70.5	55,266	11,951	0.2162	0.7838	25.57
71.5	44,090	9,937	0.2254	0.7746	20.04
72.5	36,573	6,169	0.1687	0.8313	15.52
73.5	111,312		0.0000	1.0000	12.90
74.5	115,500	2,679	0.0232	0.9768	12.90
75.5	115,794	2,973	0.0257	0.9743	12.60
76.5	113,431	2,419	0.0213	0.9787	12.28
77.5	107,097		0.0000	1.0000	12.02
78.5	103,099	4,571	0.0443	0.9557	12.02

PLACEMENT BAND 1913-2018 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	97,103	2,551	0.0263	0.9737	11.49
80.5	95,797	31,474	0.3285	0.6715	11.18
81.5	64,323	765	0.0119	0.9881	7.51
82.5	50,652		0.0000	1.0000	7.42
83.5	31,552	5,393	0.1709	0.8291	7.42
84.5	26,160	925	0.0354	0.9646	6.15
85.5	25,234	11,359	0.4501	0.5499	5.93
86.5	13,875	5,518	0.3977	0.6023	3.26
87.5	8,357	2,083	0.2492	0.7508	1.97
88.5	3,069	610	0.1986	0.8014	1.48
89.5	2,459	12	0.0049	0.9951	1.18
90.5	2,447		0.0000	1.0000	1.18
91.5	2,447		0.0000	1.0000	1.18
92.5	2,447	1,165	0.4762	0.5238	1.18
93.5	1,282	1,282	1.0000		0.62
94.5					


ORIGINAL CURVE ■ 1923-2018 EXPERIENCE
1910-2018 PLACEMENTS
▲ 1969-2018 EXPERIENCE
1910-2018 PLACEMENTS
● 2004-2018 EXPERIENCE
1910-2018 PLACEMENTS
IOWA 65-R2
PERCENT SURVIVING
AGE IN YEARS
0
20
40
60
80
100
120
10
30
50
70
90

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1923-2018

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	354,285,403	2,909,650	0.0082	0.9918	100.00
0.5	336,888,631	6,777,457	0.0201	0.9799	99.18
1.5	303,373,228	4,636,900	0.0153	0.9847	97.18
2.5	282,297,143	5,945,278	0.0211	0.9789	95.70
3.5	270,472,098	2,155,309	0.0080	0.9920	93.68
4.5	252,084,949	1,663,610	0.0066	0.9934	92.94
5.5	239,131,084	776,269	0.0032	0.9968	92.32
6.5	215,075,553	416,516	0.0019	0.9981	92.02
7.5	208,718,942	359,252	0.0017	0.9983	91.84
8.5	205,076,222	233,178	0.0011	0.9989	91.69
9.5	197,900,522	187,121	0.0009	0.9991	91.58
10.5	177,155,504	169,037	0.0010	0.9990	91.50
11.5	167,891,392	178,706	0.0011	0.9989	91.41
12.5	162,431,744	339,999	0.0021	0.9979	91.31
13.5	160,999,058	150,842	0.0009	0.9991	91.12
14.5	161,955,983	196,915	0.0012	0.9988	91.03
15.5	162,655,159	129,233	0.0008	0.9992	90.92
16.5	157,895,131	69,462	0.0004	0.9996	90.85
17.5	153,603,508	145,331	0.0009	0.9991	90.81
18.5	149,785,089	145,997	0.0010	0.9990	90.73
19.5	149,855,747	120,353	0.0008	0.9992	90.64
20.5	135,617,313	234,602	0.0017	0.9983	90.56
21.5	135,431,057	129,086	0.0010	0.9990	90.41
22.5	133,229,342	132,763	0.0010	0.9990	90.32
23.5	132,299,024	99,151	0.0007	0.9993	90.23
24.5	130,410,392	107,534	0.0008	0.9992	90.16
25.5	127,294,313	81,139	0.0006	0.9994	90.09
26.5	121,856,403	265,967	0.0022	0.9978	90.03
27.5	102,954,965	98,941	0.0010	0.9990	89.84
28.5	96,293,255	71,513	0.0007	0.9993	89.75
29.5	87,343,012	96,893	0.0011	0.9989	89.68
30.5	76,770,570	131,024	0.0017	0.9983	89.58
31.5	72,433,506	114,150	0.0016	0.9984	89.43
32.5	68,185,137	383,253	0.0056	0.9944	89.29
33.5	63,501,447	356,427	0.0056	0.9944	88.79
34.5	61,558,263	159,742	0.0026	0.9974	88.29
35.5	59,634,787	61,034	0.0010	0.9990	88.06
36.5	56,883,646	38,813	0.0007	0.9993	87.97
37.5	49,093,681	27,916	0.0006	0.9994	87.91
38.5	47,702,910	37,015	0.0008	0.9992	87.86

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1923-2018

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	46,057,595	480,501	0.0104	0.9896	87.79
40.5	44,307,918	144,769	0.0033	0.9967	86.88
41.5	42,498,993	324,920	0.0076	0.9924	86.59
42.5	39,119,323	61,346	0.0016	0.9984	85.93
43.5	38,105,639	41,038	0.0011	0.9989	85.80
44.5	37,164,549	96,887	0.0026	0.9974	85.70
45.5	35,610,952	195,698	0.0055	0.9945	85.48
46.5	33,534,285	29,478	0.0009	0.9991	85.01
47.5	32,071,502	112,744	0.0035	0.9965	84.94
48.5	30,197,469	28,884	0.0010	0.9990	84.64
49.5	28,007,909	14,039	0.0005	0.9995	84.56
50.5	25,432,330	244,791	0.0096	0.9904	84.51
51.5	21,678,646	20,485	0.0009	0.9991	83.70
52.5	19,899,894	35,562	0.0018	0.9982	83.62
53.5	17,082,871	18,889	0.0011	0.9989	83.47
54.5	14,113,592	20,312	0.0014	0.9986	83.38
55.5	12,853,042	7,789	0.0006	0.9994	83.26
56.5	10,730,521	74,626	0.0070	0.9930	83.21
57.5	9,066,086	7,736	0.0009	0.9991	82.63
58.5	8,328,470	8,860	0.0011	0.9989	82.56
59.5	7,484,652	7,446	0.0010	0.9990	82.47
60.5	6,371,227	8,769	0.0014	0.9986	82.39
61.5	4,994,466	4,126	0.0008	0.9992	82.28
62.5	4,254,987	6,089	0.0014	0.9986	82.21
63.5	3,744,093	3,100	0.0008	0.9992	82.09
64.5	3,410,528	1,873	0.0005	0.9995	82.02
65.5	2,178,295	8,476	0.0039	0.9961	81.98
66.5	2,051,338	9,329	0.0045	0.9955	81.66
67.5	1,561,643	1,603	0.0010	0.9990	81.29
68.5	1,359,893	556	0.0004	0.9996	81.20
69.5	1,195,051	661	0.0006	0.9994	81.17
70.5	1,114,432	584	0.0005	0.9995	81.13
71.5	1,102,025	6,100	0.0055	0.9945	81.08
72.5	1,063,643	1,184	0.0011	0.9989	80.63
73.5	999,782	1,113	0.0011	0.9989	80.54
74.5	982,330	731	0.0007	0.9993	80.45
75.5	968,942	777	0.0008	0.9992	80.40
76.5	957,346	8,080	0.0084	0.9916	80.33
77.5	881,330	2,272	0.0026	0.9974	79.65
78.5	769,820	3,908	0.0051	0.9949	79.45

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1923-2018

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	742,159	4,752	0.0064	0.9936	79.04
80.5	610,346	10,341	0.0169	0.9831	78.54
81.5	599,173	10,200	0.0170	0.9830	77.21
82.5	561,340	9,363	0.0167	0.9833	75.89
83.5	541,932	13,492	0.0249	0.9751	74.63
84.5	527,982	4,893	0.0093	0.9907	72.77
85.5	522,895	4,110	0.0079	0.9921	72.09
86.5	515,170	4,497	0.0087	0.9913	71.53
87.5	328,249	5,840	0.0178	0.9822	70.90
88.5	301,401	2,494	0.0083	0.9917	69.64
89.5	264,065	2,604	0.0099	0.9901	69.07
90.5	218,208	15,345	0.0703	0.9297	68.38
91.5	176,471	3,478	0.0197	0.9803	63.58
92.5	87,909	5	0.0001	0.9999	62.32
93.5	53,152		0.0000	1.0000	62.32
94.5	20,555	75	0.0037	0.9963	62.32
95.5	17,862	8	0.0004	0.9996	62.09
96.5	16,764	13	0.0008	0.9992	62.06
97.5	16,445	2	0.0001	0.9999	62.02
98.5	591	38	0.0647	0.9353	62.01
99.5	553	15	0.0276	0.9724	58.00
100.5	538	10	0.0190	0.9810	56.39
101.5	522	5	0.0092	0.9908	55.32
102.5	518		0.0000	1.0000	54.81
103.5	518		0.0000	1.0000	54.81
104.5	518		0.0000	1.0000	54.81
105.5	77		0.0000	1.0000	54.81
106.5	77		0.0000	1.0000	54.81
107.5	12		0.0000	1.0000	54.81
108.5					54.81

PLACEMENT BAND 1910-2018 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	325,983,093	2,908,169	0.0089	0.9911	100.00
0.5	309,846,948	6,755,620	0.0218	0.9782	99.11
1.5	279,941,801	4,615,217	0.0165	0.9835	96.95
2.5	260,509,526	5,901,667	0.0227	0.9773	95.35
3.5	252,848,669	2,115,995	0.0084	0.9916	93.19
4.5	238,655,652	1,600,421	0.0067	0.9933	92.41
5.5	227,193,528	696,767	0.0031	0.9969	91.79
6.5	206,240,045	402,242	0.0020	0.9980	91.51
7.5	201,902,074	277,351	0.0014	0.9986	91.33
8.5	199,263,019	196,649	0.0010	0.9990	91.20
9.5	192,670,290	142,507	0.0007	0.9993	91.11
10.5	172,800,455	143,550	0.0008	0.9992	91.05
11.5	165,800,576	147,638	0.0009	0.9991	90.97
12.5	160,700,298	173,317	0.0011	0.9989	90.89
13.5	159,662,869	106,195	0.0007	0.9993	90.79
14.5	160,798,235	176,157	0.0011	0.9989	90.73
15.5	161,354,342	112,008	0.0007	0.9993	90.63
16.5	156,621,563	60,276	0.0004	0.9996	90.57
17.5	152,554,475	141,730	0.0009	0.9991	90.53
18.5	148,660,440	120,959	0.0008	0.9992	90.45
19.5	148,694,071	95,142	0.0006	0.9994	90.38
20.5	134,392,208	214,796	0.0016	0.9984	90.32
21.5	134,109,528	124,965	0.0009	0.9991	90.17
22.5	131,764,578	124,380	0.0009	0.9991	90.09
23.5	130,836,754	91,606	0.0007	0.9993	90.01
24.5	128,937,596	36,647	0.0003	0.9997	89.94
25.5	125,894,035	61,513	0.0005	0.9995	89.92
26.5	120,467,452	242,780	0.0020	0.9980	89.87
27.5	101,643,456	70,223	0.0007	0.9993	89.69
28.5	95,087,901	48,317	0.0005	0.9995	89.63
29.5	86,192,243	43,523	0.0005	0.9995	89.58
30.5	75,718,860	37,977	0.0005	0.9995	89.54
31.5	71,471,891	78,577	0.0011	0.9989	89.49
32.5	67,271,886	173,189	0.0026	0.9974	89.40
33.5	62,800,041	203,587	0.0032	0.9968	89.17
34.5	61,017,795	142,943	0.0023	0.9977	88.88
35.5	59,114,098	33,971	0.0006	0.9994	88.67
36.5	56,409,355	18,401	0.0003	0.9997	88.62
37.5	48,798,434	16,553	0.0003	0.9997	88.59
38.5	47,451,655	28,322	0.0006	0.9994	88.56

PLACEMENT BAND 1910-2018 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	45,826,070	478,912	0.0105	0.9895	88.51
40.5	44,112,244	94,698	0.0021	0.9979	87.58
41.5	42,317,587	288,909	0.0068	0.9932	87.39
42.5	38,990,527	47,873	0.0012	0.9988	86.80
43.5	38,003,592	40,653	0.0011	0.9989	86.69
44.5	37,101,612	93,450	0.0025	0.9975	86.60
45.5	35,565,817	195,680	0.0055	0.9945	86.38
46.5	33,489,168	23,456	0.0007	0.9993	85.90
47.5	32,032,407	112,744	0.0035	0.9965	85.84
48.5	30,196,885	28,884	0.0010	0.9990	85.54
49.5	28,007,324	14,039	0.0005	0.9995	85.46
50.5	25,431,745	244,791	0.0096	0.9904	85.42
51.5	21,678,061	20,485	0.0009	0.9991	84.59
52.5	19,899,309	35,562	0.0018	0.9982	84.51
53.5	17,082,286	18,889	0.0011	0.9989	84.36
54.5	14,113,007	20,312	0.0014	0.9986	84.27
55.5	12,853,040	7,789	0.0006	0.9994	84.15
56.5	10,730,519	74,626	0.0070	0.9930	84.10
57.5	9,066,084	7,736	0.0009	0.9991	83.51
58.5	8,328,470	8,860	0.0011	0.9989	83.44
59.5	7,484,652	7,446	0.0010	0.9990	83.35
60.5	6,371,227	8,769	0.0014	0.9986	83.27
61.5	4,994,466	4,126	0.0008	0.9992	83.15
62.5	4,254,987	6,089	0.0014	0.9986	83.09
63.5	3,744,093	3,100	0.0008	0.9992	82.97
64.5	3,410,528	1,873	0.0005	0.9995	82.90
65.5	2,178,295	8,476	0.0039	0.9961	82.85
66.5	2,051,338	9,329	0.0045	0.9955	82.53
67.5	1,561,643	1,603	0.0010	0.9990	82.16
68.5	1,359,893	556	0.0004	0.9996	82.07
69.5	1,195,051	661	0.0006	0.9994	82.04
70.5	1,114,432	584	0.0005	0.9995	81.99
71.5	1,102,025	6,100	0.0055	0.9945	81.95
72.5	1,063,643	1,184	0.0011	0.9989	81.50
73.5	999,782	1,113	0.0011	0.9989	81.40
74.5	982,330	731	0.0007	0.9993	81.31
75.5	968,942	777	0.0008	0.9992	81.25
76.5	957,346	8,080	0.0084	0.9916	81.19
77.5	881,330	2,272	0.0026	0.9974	80.50
78.5	769,820	3,908	0.0051	0.9949	80.30

PLACEMENT BAND 1910-2018 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	742,159	4,752	0.0064	0.9936	79.89
80.5	610,346	10,341	0.0169	0.9831	79.38
81.5	599,173	10,200	0.0170	0.9830	78.03
82.5	561,340	9,363	0.0167	0.9833	76.70
83.5	541,932	13,492	0.0249	0.9751	75.42
84.5	527,982	4,893	0.0093	0.9907	73.55
85.5	522,895	4,110	0.0079	0.9921	72.86
86.5	515,170	4,497	0.0087	0.9913	72.29
87.5	328,249	5,840	0.0178	0.9822	71.66
88.5	301,401	2,494	0.0083	0.9917	70.39
89.5	264,065	2,604	0.0099	0.9901	69.80
90.5	218,208	15,345	0.0703	0.9297	69.12
91.5	176,471	3,478	0.0197	0.9803	64.25
92.5	87,909	5	0.0001	0.9999	62.99
93.5	53,152		0.0000	1.0000	62.98
94.5	20,555	75	0.0037	0.9963	62.98
95.5	17,862	8	0.0004	0.9996	62.75
96.5	16,764	13	0.0008	0.9992	62.73
97.5	16,445	2	0.0001	0.9999	62.68
98.5	591	38	0.0647	0.9353	62.67
99.5	553	15	0.0276	0.9724	58.62
100.5	538	10	0.0190	0.9810	57.00
101.5	522	5	0.0092	0.9908	55.91
102.5	518		0.0000	1.0000	55.40
103.5	518		0.0000	1.0000	55.40
104.5	518		0.0000	1.0000	55.40
105.5	77		0.0000	1.0000	55.40
106.5	77		0.0000	1.0000	55.40
107.5	12		0.0000	1.0000	55.40
108.5					55.40

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 2004-2018

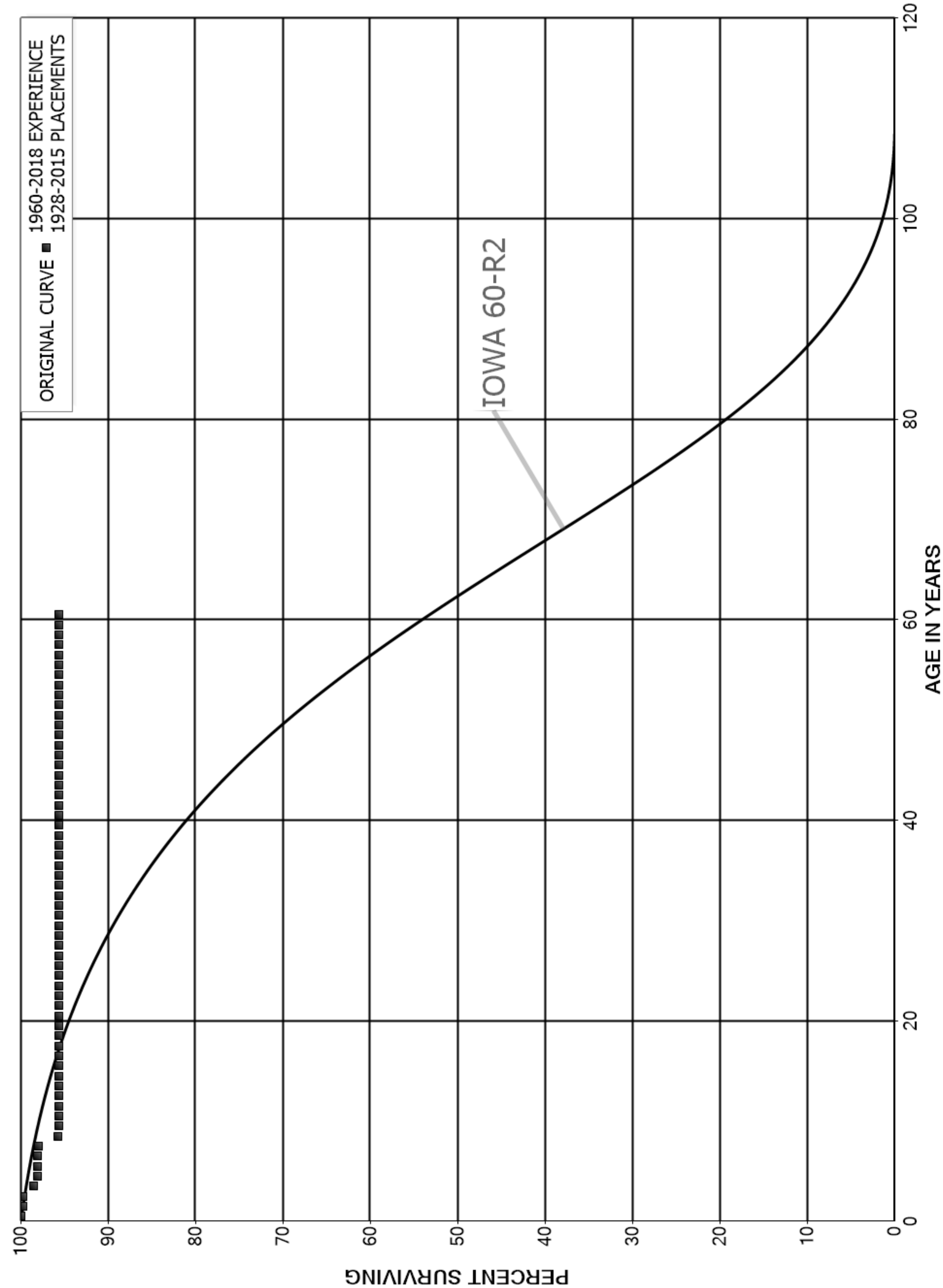
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	185,210,551	2,703,784	0.0146	0.9854	100.00
0.5	173,659,565	6,001,753	0.0346	0.9654	98.54
1.5	144,202,568	4,471,897	0.0310	0.9690	95.13
2.5	127,029,428	3,236,106	0.0255	0.9745	92.18
3.5	122,600,290	1,798,447	0.0147	0.9853	89.84
4.5	105,243,994	1,488,104	0.0141	0.9859	88.52
5.5	107,908,622	578,213	0.0054	0.9946	87.27
6.5	82,755,914	284,753	0.0034	0.9966	86.80
7.5	79,482,097	164,573	0.0021	0.9979	86.50
8.5	77,244,037	108,343	0.0014	0.9986	86.32
9.5	71,365,016	59,789	0.0008	0.9992	86.20
10.5	53,107,609	59,918	0.0011	0.9989	86.13
11.5	49,540,356	96,286	0.0019	0.9981	86.03
12.5	63,652,630	82,947	0.0013	0.9987	85.86
13.5	68,654,354	43,486	0.0006	0.9994	85.75
14.5	77,856,451	111,488	0.0014	0.9986	85.70
15.5	87,742,647	27,855	0.0003	0.9997	85.57
16.5	86,901,477	34,773	0.0004	0.9996	85.55
17.5	86,352,954	92,136	0.0011	0.9989	85.51
18.5	86,567,033	65,544	0.0008	0.9992	85.42
19.5	88,101,646	26,176	0.0003	0.9997	85.36
20.5	74,791,706	56,761	0.0008	0.9992	85.33
21.5	77,379,600	57,098	0.0007	0.9993	85.27
22.5	82,914,011	83,272	0.0010	0.9990	85.20
23.5	83,280,818	63,738	0.0008	0.9992	85.12
24.5	83,163,965	21,139	0.0003	0.9997	85.05
25.5	81,409,672	31,074	0.0004	0.9996	85.03
26.5	78,111,442	34,388	0.0004	0.9996	85.00
27.5	62,728,219	16,004	0.0003	0.9997	84.96
28.5	57,144,357	27,095	0.0005	0.9995	84.94
29.5	49,271,327	16,138	0.0003	0.9997	84.90
30.5	40,243,608	14,917	0.0004	0.9996	84.87
31.5	37,955,965	74,218	0.0020	0.9980	84.84
32.5	35,163,916	26,786	0.0008	0.9992	84.67
33.5	32,753,664	103,295	0.0032	0.9968	84.61
34.5	33,242,877	16,762	0.0005	0.9995	84.34
35.5	34,088,353	16,674	0.0005	0.9995	84.30
36.5	35,185,322	11,146	0.0003	0.9997	84.26
37.5	29,023,546	14,572	0.0005	0.9995	84.23
38.5	30,638,026	17,836	0.0006	0.9994	84.19

PLACEMENT BAND 1910-2018 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	31,801,564	413,492	0.0130	0.9870	84.14
40.5	31,345,411	78,259	0.0025	0.9975	83.05
41.5	31,931,692	281,654	0.0088	0.9912	82.84
42.5	29,984,284	26,526	0.0009	0.9991	82.11
43.5	29,757,593	18,908	0.0006	0.9994	82.04
44.5	29,687,564	90,894	0.0031	0.9969	81.98
45.5	29,253,437	194,177	0.0066	0.9934	81.73
46.5	28,510,004	10,676	0.0004	0.9996	81.19
47.5	27,786,589	91,327	0.0033	0.9967	81.16
48.5	26,441,577	11,984	0.0005	0.9995	80.89
49.5	24,627,036	11,678	0.0005	0.9995	80.86
50.5	23,241,717	243,238	0.0105	0.9895	80.82
51.5	19,584,135	10,124	0.0005	0.9995	79.97
52.5	18,319,313	35,389	0.0019	0.9981	79.93
53.5	15,709,787	18,658	0.0012	0.9988	79.78
54.5	12,906,925	14,486	0.0011	0.9989	79.68
55.5	11,733,682	7,536	0.0006	0.9994	79.59
56.5	9,623,400	69,415	0.0072	0.9928	79.54
57.5	8,006,290	7,184	0.0009	0.9991	78.97
58.5	7,333,034	6,870	0.0009	0.9991	78.90
59.5	6,502,728	4,303	0.0007	0.9993	78.82
60.5	5,403,546	8,420	0.0016	0.9984	78.77
61.5	4,038,211	4,002	0.0010	0.9990	78.65
62.5	3,369,176	5,697	0.0017	0.9983	78.57
63.5	2,970,420	2,884	0.0010	0.9990	78.44
64.5	2,627,206	1,451	0.0006	0.9994	78.36
65.5	1,524,481	888	0.0006	0.9994	78.32
66.5	1,405,995	1,683	0.0012	0.9988	78.27
67.5	936,304	1,341	0.0014	0.9986	78.18
68.5	746,012	492	0.0007	0.9993	78.07
69.5	581,739	472	0.0008	0.9992	78.02
70.5	501,522	535	0.0011	0.9989	77.95
71.5	493,613	1,313	0.0027	0.9973	77.87
72.5	687,467	1,168	0.0017	0.9983	77.66
73.5	649,933	1,105	0.0017	0.9983	77.53
74.5	674,999	722	0.0011	0.9989	77.40
75.5	714,185	756	0.0011	0.9989	77.32
76.5	737,898	8,071	0.0109	0.9891	77.23
77.5	750,014	2,263	0.0030	0.9970	76.39
78.5	682,988	3,907	0.0057	0.9943	76.16

PLACEMENT BAND 1910-2018 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	697,065	4,751	0.0068	0.9932	75.72
80.5	571,024	10,341	0.0181	0.9819	75.21
81.5	561,311	10,195	0.0182	0.9818	73.84
82.5	523,909	9,363	0.0179	0.9821	72.50
83.5	541,240	13,492	0.0249	0.9751	71.21
84.5	527,290	4,893	0.0093	0.9907	69.43
85.5	522,203	4,110	0.0079	0.9921	68.79
86.5	514,491	4,497	0.0087	0.9913	68.25
87.5	327,569	5,840	0.0178	0.9822	67.65
88.5	300,721	2,493	0.0083	0.9917	66.44
89.5	263,385	2,604	0.0099	0.9901	65.89
90.5	218,111	15,345	0.0704	0.9296	65.24
91.5	176,375	3,478	0.0197	0.9803	60.65
92.5	87,901	5	0.0001	0.9999	59.46
93.5	53,152		0.0000	1.0000	59.45
94.5	20,555	75	0.0037	0.9963	59.45
95.5	17,862	8	0.0004	0.9996	59.23
96.5	16,764	13	0.0008	0.9992	59.21
97.5	16,445	2	0.0001	0.9999	59.16
98.5	591	38	0.0647	0.9353	59.16
99.5	553	15	0.0276	0.9724	55.33
100.5	538	10	0.0190	0.9810	53.80
101.5	522	5	0.0092	0.9908	52.78
102.5	518		0.0000	1.0000	52.29
103.5	518		0.0000	1.0000	52.29
104.5	518		0.0000	1.0000	52.29
105.5	77		0.0000	1.0000	52.29
106.5	77		0.0000	1.0000	52.29
107.5	12		0.0000	1.0000	52.29
108.5					52.29


ORIGINAL CURVE ■ 1960-2018 EXPERIENCE
1928-2015 PLACEMENTS
IOWA 60-R2
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120

PLACEMENT BAND 1928-2015 EXPERIENCE BAND 1960-2018

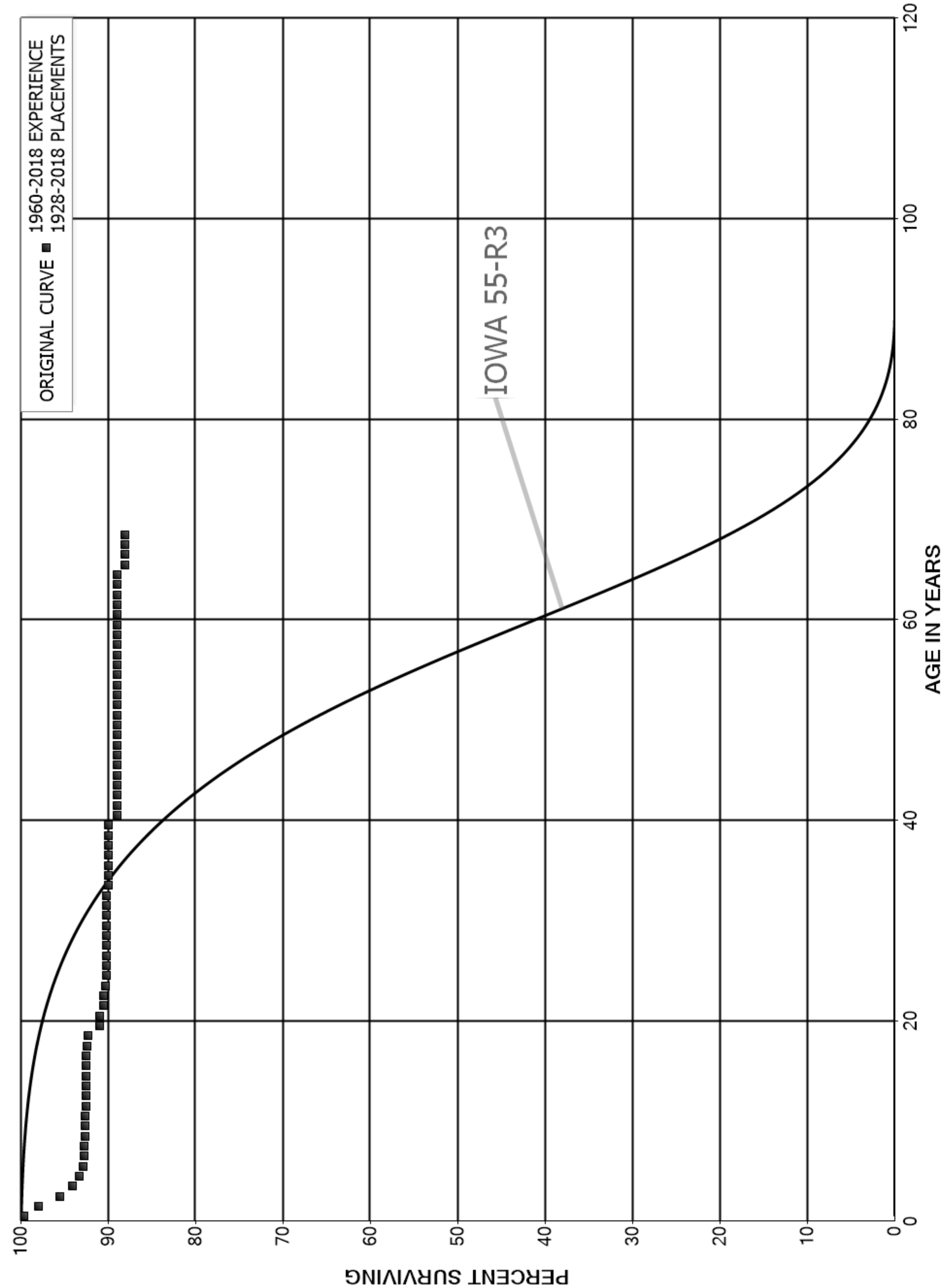
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,913,877		0.0000	1.0000	100.00
0.5	1,924,732	6,017	0.0031	0.9969	100.00
1.5	1,910,774		0.0000	1.0000	99.69
2.5	1,912,034	21,937	0.0115	0.9885	99.69
3.5	1,887,655	9,903	0.0052	0.9948	98.54
4.5	1,855,183	1	0.0000	1.0000	98.03
5.5	1,847,182		0.0000	1.0000	98.03
6.5	1,816,786	618	0.0003	0.9997	98.03
7.5	1,809,911	41,888	0.0231	0.9769	97.99
8.5	1,774,280	1,681	0.0009	0.9991	95.73
9.5	1,710,215		0.0000	1.0000	95.63
10.5	1,710,215		0.0000	1.0000	95.63
11.5	1,710,215		0.0000	1.0000	95.63
12.5	1,720,744		0.0000	1.0000	95.63
13.5	1,713,250		0.0000	1.0000	95.63
14.5	1,714,215		0.0000	1.0000	95.63
15.5	1,714,003		0.0000	1.0000	95.63
16.5	1,714,207		0.0000	1.0000	95.63
17.5	1,727,013		0.0000	1.0000	95.63
18.5	1,755,044		0.0000	1.0000	95.63
19.5	1,713,016		0.0000	1.0000	95.63
20.5	1,707,808		0.0000	1.0000	95.63
21.5	1,706,466		0.0000	1.0000	95.63
22.5	1,341,681		0.0000	1.0000	95.63
23.5	1,347,916		0.0000	1.0000	95.63
24.5	1,331,707		0.0000	1.0000	95.63
25.5	1,284,021		0.0000	1.0000	95.63
26.5	1,166,191		0.0000	1.0000	95.63
27.5	1,121,920		0.0000	1.0000	95.63
28.5	1,037,925		0.0000	1.0000	95.63
29.5	990,913		0.0000	1.0000	95.63
30.5	840,605		0.0000	1.0000	95.63
31.5	878,712		0.0000	1.0000	95.63
32.5	772,860		0.0000	1.0000	95.63
33.5	733,695		0.0000	1.0000	95.63
34.5	733,695		0.0000	1.0000	95.63
35.5	733,695	39	0.0001	0.9999	95.63
36.5	733,656		0.0000	1.0000	95.63
37.5	653,206		0.0000	1.0000	95.63
38.5	399,447		0.0000	1.0000	95.63

PLACEMENT BAND 1928-2015 EXPERIENCE BAND 1960-2018

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	381,719		0.0000	1.0000	95.63
40.5	374,419		0.0000	1.0000	95.63
41.5	367,588		0.0000	1.0000	95.63
42.5	270,317		0.0000	1.0000	95.63
43.5	258,742		0.0000	1.0000	95.63
44.5	205,304		0.0000	1.0000	95.63
45.5	200,375		0.0000	1.0000	95.63
46.5	200,375		0.0000	1.0000	95.63
47.5	186,675		0.0000	1.0000	95.63
48.5	184,233		0.0000	1.0000	95.63
49.5	171,088		0.0000	1.0000	95.63
50.5	160,591		0.0000	1.0000	95.63
51.5	160,591		0.0000	1.0000	95.63
52.5	148,704		0.0000	1.0000	95.63
53.5	148,704		0.0000	1.0000	95.63
54.5	129,289		0.0000	1.0000	95.63
55.5	129,289		0.0000	1.0000	95.63
56.5	122,263		0.0000	1.0000	95.63
57.5	122,040		0.0000	1.0000	95.63
58.5	109,819		0.0000	1.0000	95.63
59.5	107,833		0.0000	1.0000	95.63
60.5	107,622		0.0000	1.0000	95.63
61.5	88,287		0.0000	1.0000	95.63
62.5	56,068		0.0000	1.0000	95.63
63.5	56,068		0.0000	1.0000	95.63
64.5	56,068		0.0000	1.0000	95.63
65.5	56,068		0.0000	1.0000	95.63
66.5	56,068		0.0000	1.0000	95.63
67.5	56,068		0.0000	1.0000	95.63
68.5	56,068		0.0000	1.0000	95.63
69.5	56,068		0.0000	1.0000	95.63
70.5	56,068		0.0000	1.0000	95.63
71.5	56,068		0.0000	1.0000	95.63
72.5	56,068		0.0000	1.0000	95.63
73.5	56,068		0.0000	1.0000	95.63
74.5	56,068		0.0000	1.0000	95.63
75.5	56,068		0.0000	1.0000	95.63
76.5	56,068		0.0000	1.0000	95.63
77.5	56,068		0.0000	1.0000	95.63
78.5	56,068		0.0000	1.0000	95.63

PLACEMENT BAND 1928-2015 EXPERIENCE BAND 1960-2018

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	56,068		0.0000	1.0000	95.63
80.5	56,068		0.0000	1.0000	95.63
81.5	56,068		0.0000	1.0000	95.63
82.5	56,068		0.0000	1.0000	95.63
83.5	56,068		0.0000	1.0000	95.63
84.5	56,068		0.0000	1.0000	95.63
85.5	56,068		0.0000	1.0000	95.63
86.5	56,068		0.0000	1.0000	95.63
87.5	56,068		0.0000	1.0000	95.63
88.5	56,068		0.0000	1.0000	95.63
89.5	56,068		0.0000	1.0000	95.63
90.5					95.63


ORIGINAL CURVE ■ 1960-2018 EXPERIENCE
1928-2018 PLACEMENTS
IOWA 55-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
20
40
60
80
100
120

PLACEMENT BAND 1928-2018 EXPERIENCE BAND 1960-2018

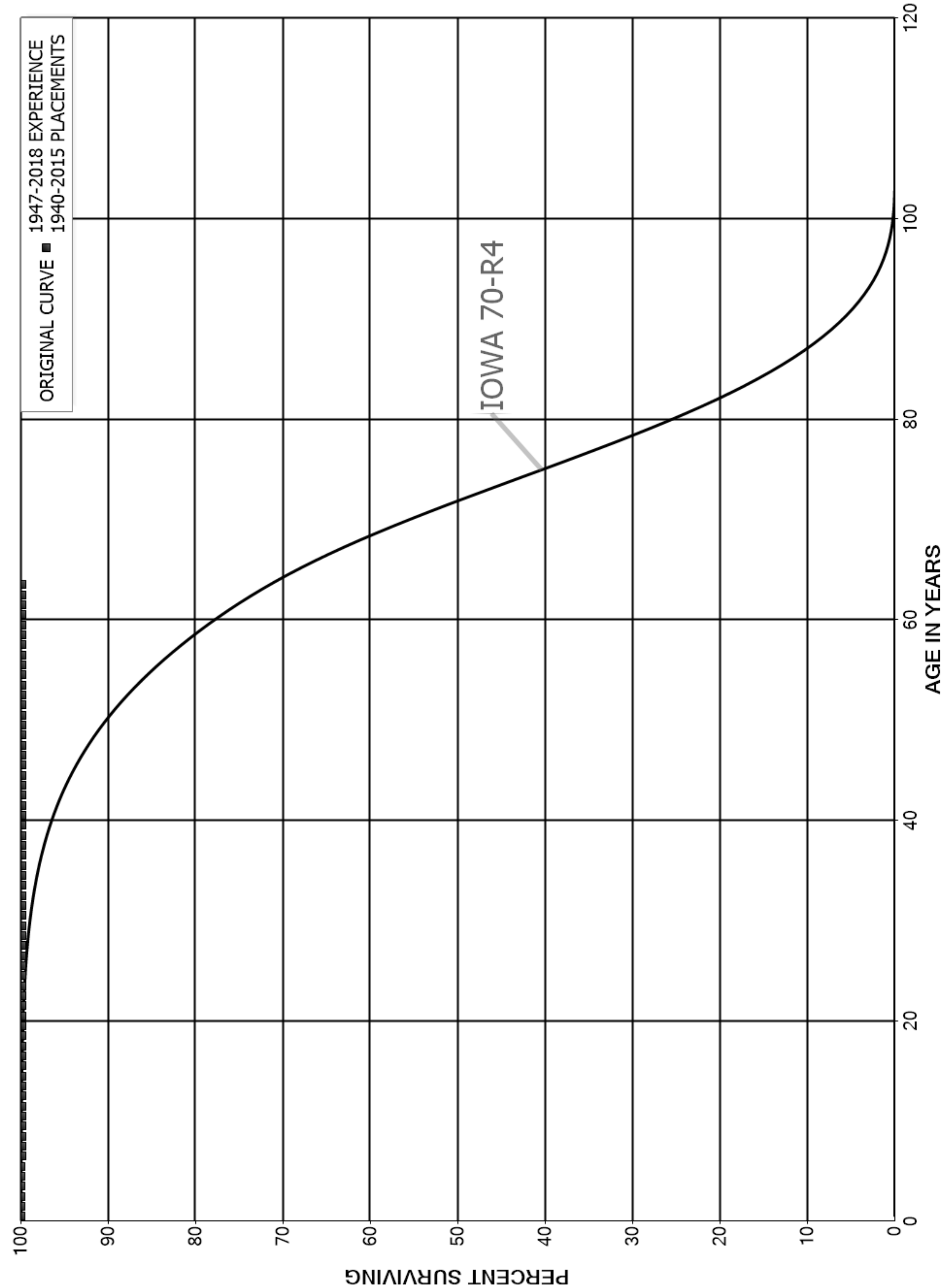
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,694,728	92,419	0.0041	0.9959	100.00
0.5	21,960,004	372,637	0.0170	0.9830	99.59
1.5	20,141,697	489,492	0.0243	0.9757	97.90
2.5	18,014,104	274,274	0.0152	0.9848	95.52
3.5	16,782,944	136,462	0.0081	0.9919	94.07
4.5	16,139,027	82,959	0.0051	0.9949	93.30
5.5	15,517,614	14,136	0.0009	0.9991	92.82
6.5	13,374,928	3,862	0.0003	0.9997	92.74
7.5	13,151,124	9,234	0.0007	0.9993	92.71
8.5	13,062,652		0.0000	1.0000	92.65
9.5	12,636,259		0.0000	1.0000	92.65
10.5	12,541,656	16,150	0.0013	0.9987	92.65
11.5	12,739,992		0.0000	1.0000	92.53
12.5	12,631,873	3,571	0.0003	0.9997	92.53
13.5	11,952,217		0.0000	1.0000	92.50
14.5	5,861,123		0.0000	1.0000	92.50
15.5	5,847,683	4	0.0000	1.0000	92.50
16.5	5,491,175	7,096	0.0013	0.9987	92.50
17.5	5,403,767	4,580	0.0008	0.9992	92.38
18.5	5,290,895	76,914	0.0145	0.9855	92.30
19.5	5,233,559		0.0000	1.0000	90.96
20.5	5,173,537	23,390	0.0045	0.9955	90.96
21.5	5,096,841		0.0000	1.0000	90.55
22.5	4,878,320	13,902	0.0028	0.9972	90.55
23.5	4,867,080	5,855	0.0012	0.9988	90.29
24.5	4,549,245		0.0000	1.0000	90.19
25.5	4,442,389		0.0000	1.0000	90.19
26.5	4,057,285		0.0000	1.0000	90.19
27.5	3,822,475	74	0.0000	1.0000	90.19
28.5	3,525,711	35	0.0000	1.0000	90.18
29.5	3,451,808		0.0000	1.0000	90.18
30.5	3,281,681		0.0000	1.0000	90.18
31.5	3,299,097	13	0.0000	1.0000	90.18
32.5	3,182,628	6,963	0.0022	0.9978	90.18
33.5	3,133,855	24	0.0000	1.0000	89.98
34.5	3,130,121	10	0.0000	1.0000	89.98
35.5	3,127,706	2,380	0.0008	0.9992	89.98
36.5	3,120,585		0.0000	1.0000	89.92
37.5	2,472,701	43	0.0000	1.0000	89.92
38.5	2,286,723		0.0000	1.0000	89.91

PLACEMENT BAND 1928-2018 EXPERIENCE BAND 1960-2018

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	2,123,666	22,685	0.0107	0.9893	89.91
40.5	2,066,829	99	0.0000	1.0000	88.95
41.5	1,992,287		0.0000	1.0000	88.95
42.5	1,457,254		0.0000	1.0000	88.95
43.5	1,367,743		0.0000	1.0000	88.95
44.5	1,305,319	20	0.0000	1.0000	88.95
45.5	1,256,970	5	0.0000	1.0000	88.95
46.5	1,254,128		0.0000	1.0000	88.95
47.5	1,113,342		0.0000	1.0000	88.95
48.5	1,060,892		0.0000	1.0000	88.95
49.5	781,040		0.0000	1.0000	88.95
50.5	435,194		0.0000	1.0000	88.95
51.5	417,414	82	0.0002	0.9998	88.95
52.5	404,303		0.0000	1.0000	88.93
53.5	404,303	86	0.0002	0.9998	88.93
54.5	330,478		0.0000	1.0000	88.91
55.5	321,465		0.0000	1.0000	88.91
56.5	312,351		0.0000	1.0000	88.91
57.5	312,351	4	0.0000	1.0000	88.91
58.5	275,779		0.0000	1.0000	88.91
59.5	269,229		0.0000	1.0000	88.91
60.5	269,229		0.0000	1.0000	88.91
61.5	161,975		0.0000	1.0000	88.91
62.5	161,128		0.0000	1.0000	88.91
63.5	116,246		0.0000	1.0000	88.91
64.5	116,246	1,052	0.0091	0.9909	88.91
65.5	115,194		0.0000	1.0000	88.11
66.5	114,265		0.0000	1.0000	88.11
67.5	110,867		0.0000	1.0000	88.11
68.5	35,513		0.0000	1.0000	88.11
69.5	35,513		0.0000	1.0000	88.11
70.5	35,513		0.0000	1.0000	88.11
71.5	35,513		0.0000	1.0000	88.11
72.5	52,335	36	0.0007	0.9993	88.11
73.5	35,477		0.0000	1.0000	88.04
74.5	35,477		0.0000	1.0000	88.04
75.5	35,476		0.0000	1.0000	88.04
76.5	35,476		0.0000	1.0000	88.04
77.5	35,476		0.0000	1.0000	88.04
78.5	35,476		0.0000	1.0000	88.04

PLACEMENT BAND 1928-2018 EXPERIENCE BAND 1960-2018

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	35,476		0.0000	1.0000	88.04
80.5	35,476	157	0.0044	0.9956	88.04
81.5	35,320		0.0000	1.0000	87.66
82.5	27,806		0.0000	1.0000	87.66
83.5	27,806		0.0000	1.0000	87.66
84.5	27,806		0.0000	1.0000	87.66
85.5	27,806		0.0000	1.0000	87.66
86.5	27,806		0.0000	1.0000	87.66
87.5	27,806		0.0000	1.0000	87.66
88.5	27,806		0.0000	1.0000	87.66
89.5	27,806		0.0000	1.0000	87.66
90.5					87.66

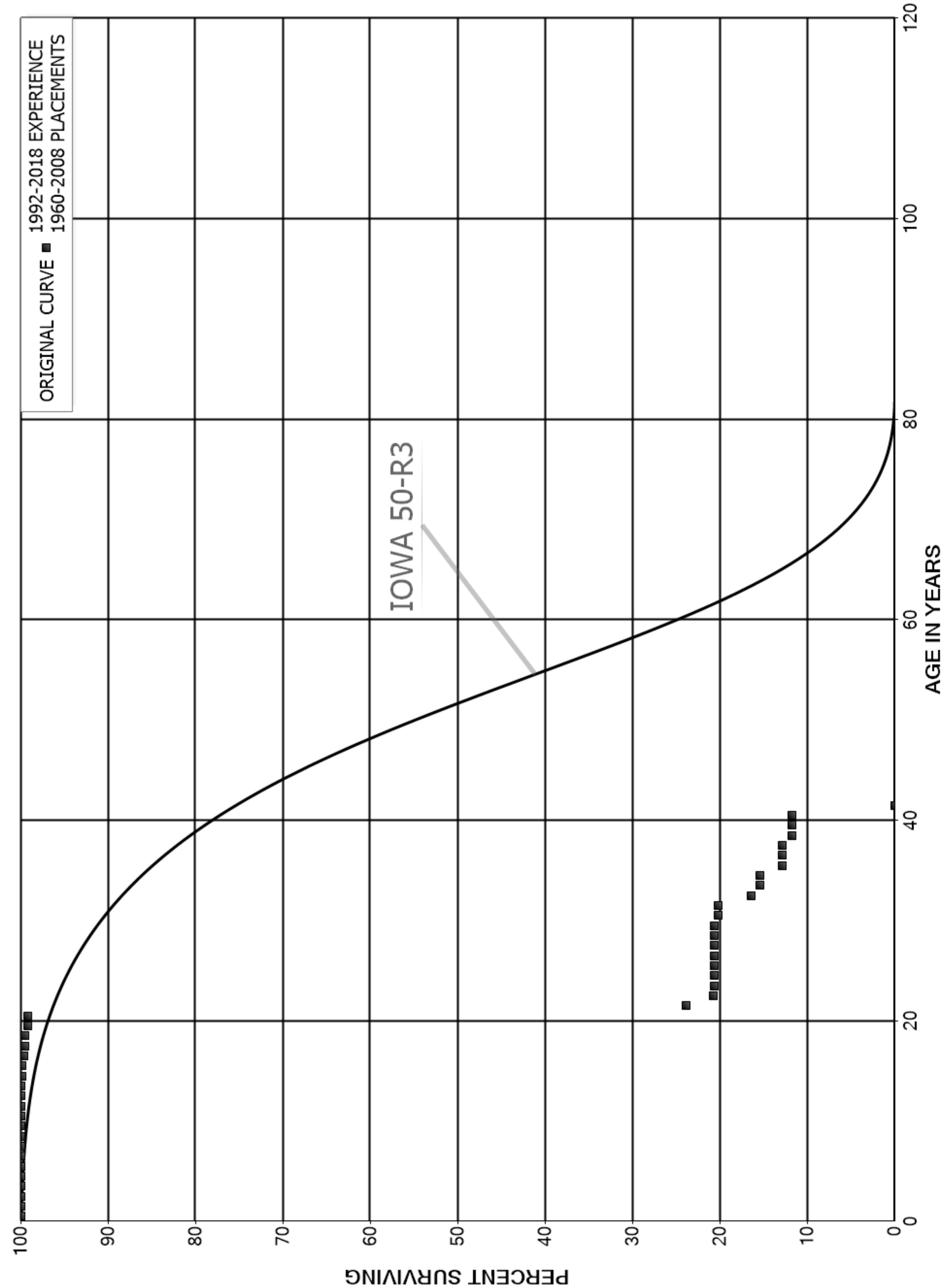

ORIGINAL CURVE ■ 1947-2018 EXPERIENCE
1940-2015 PLACEMENTS
IOWA 70-R4
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
0
20
40
60
80
100
120

PLACEMENT BAND 1940-2015 EXPERIENCE BAND 1947-2018

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	2,517,051		0.0000	1.0000	100.00
0.5	2,521,247	2,558	0.0010	0.9990	100.00
1.5	2,518,689		0.0000	1.0000	99.90
2.5	2,518,689		0.0000	1.0000	99.90
3.5	2,059,402		0.0000	1.0000	99.90
4.5	2,059,402		0.0000	1.0000	99.90
5.5	2,059,953	551	0.0003	0.9997	99.90
6.5	2,083,172		0.0000	1.0000	99.87
7.5	2,083,172		0.0000	1.0000	99.87
8.5	2,083,172		0.0000	1.0000	99.87
9.5	2,083,172		0.0000	1.0000	99.87
10.5	2,083,172		0.0000	1.0000	99.87
11.5	2,083,043		0.0000	1.0000	99.87
12.5	2,082,837		0.0000	1.0000	99.87
13.5	2,082,791		0.0000	1.0000	99.87
14.5	2,071,330		0.0000	1.0000	99.87
15.5	2,069,023		0.0000	1.0000	99.87
16.5	2,069,023		0.0000	1.0000	99.87
17.5	2,069,023		0.0000	1.0000	99.87
18.5	2,069,023		0.0000	1.0000	99.87
19.5	2,069,023		0.0000	1.0000	99.87
20.5	2,069,023		0.0000	1.0000	99.87
21.5	2,069,023		0.0000	1.0000	99.87
22.5	2,068,894		0.0000	1.0000	99.87
23.5	2,068,894		0.0000	1.0000	99.87
24.5	2,068,894		0.0000	1.0000	99.87
25.5	2,068,894		0.0000	1.0000	99.87
26.5	2,024,376		0.0000	1.0000	99.87
27.5	1,971,989		0.0000	1.0000	99.87
28.5	1,963,264		0.0000	1.0000	99.87
29.5	304,432		0.0000	1.0000	99.87
30.5	49,602		0.0000	1.0000	99.87
31.5	49,602		0.0000	1.0000	99.87
32.5	49,602		0.0000	1.0000	99.87
33.5	49,602		0.0000	1.0000	99.87
34.5	49,602		0.0000	1.0000	99.87
35.5	49,602		0.0000	1.0000	99.87
36.5	47,421		0.0000	1.0000	99.87
37.5	44,338		0.0000	1.0000	99.87
38.5	44,338		0.0000	1.0000	99.87

PLACEMENT BAND 1940-2015 EXPERIENCE BAND 1947-2018

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	44,338		0.0000	1.0000	99.87
40.5	43,790		0.0000	1.0000	99.87
41.5	43,088		0.0000	1.0000	99.87
42.5	43,088		0.0000	1.0000	99.87
43.5	43,088		0.0000	1.0000	99.87
44.5	31,554		0.0000	1.0000	99.87
45.5	31,554		0.0000	1.0000	99.87
46.5	31,554		0.0000	1.0000	99.87
47.5	29,070		0.0000	1.0000	99.87
48.5	29,070		0.0000	1.0000	99.87
49.5	29,070		0.0000	1.0000	99.87
50.5	29,070		0.0000	1.0000	99.87
51.5	26,384		0.0000	1.0000	99.87
52.5	26,384		0.0000	1.0000	99.87
53.5	26,384		0.0000	1.0000	99.87
54.5	26,107		0.0000	1.0000	99.87
55.5	24,852		0.0000	1.0000	99.87
56.5	24,852		0.0000	1.0000	99.87
57.5	24,852		0.0000	1.0000	99.87
58.5	24,852		0.0000	1.0000	99.87
59.5	24,852		0.0000	1.0000	99.87
60.5	23,770		0.0000	1.0000	99.87
61.5	23,770		0.0000	1.0000	99.87
62.5	23,770		0.0000	1.0000	99.87
63.5					99.87

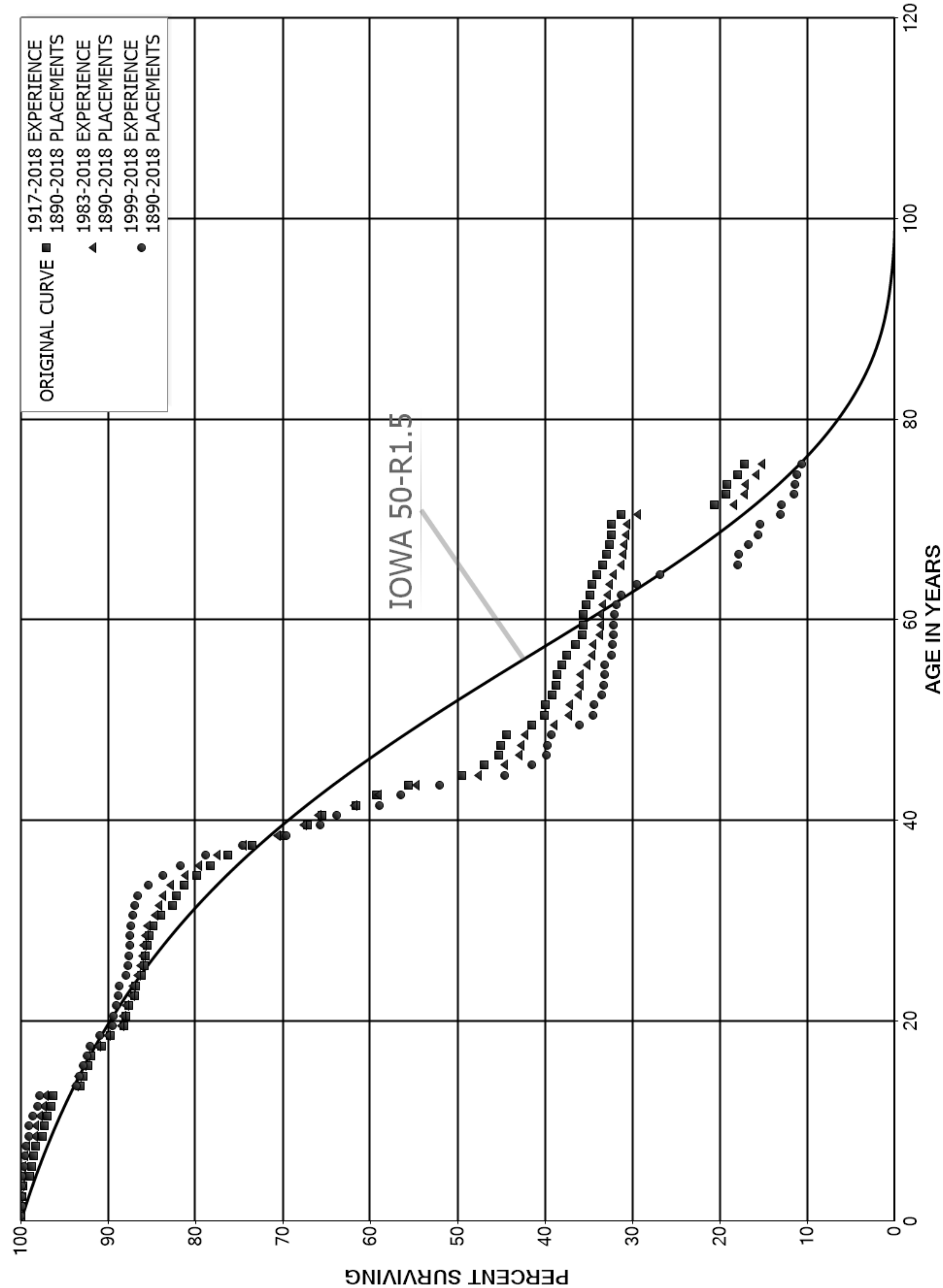

ORIGINAL CURVE ■ 1992-2018 EXPERIENCE
1960-2008 PLACEMENTS
IOWA 50-R3
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
0
20
40
60
80
100
120

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

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					


ORIGINAL CURVE ■ 1917-2018 EXPERIENCE 1890-2018 PLACEMENTS
▲ 1983-2018 EXPERIENCE 1890-2018 PLACEMENTS
● 1999-2018 EXPERIENCE 1890-2018 PLACEMENTS
IOWA 50-R1.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
0
20
40
60
80
100
120

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	167,718,775	65,133	0.0004	0.9996	100.00
0.5	158,468,634	83,207	0.0005	0.9995	99.96
1.5	141,464,138	41,237	0.0003	0.9997	99.91
2.5	137,169,033	168,778	0.0012	0.9988	99.88
3.5	131,871,141	1,068,168	0.0081	0.9919	99.76
4.5	129,090,370	222,310	0.0017	0.9983	98.95
5.5	127,443,747	293,885	0.0023	0.9977	98.78
6.5	126,103,042	327,627	0.0026	0.9974	98.55
7.5	122,289,608	961,701	0.0079	0.9921	98.29
8.5	119,881,172	223,269	0.0019	0.9981	97.52
9.5	115,024,285	427,083	0.0037	0.9963	97.34
10.5	112,105,379	515,441	0.0046	0.9954	96.98
11.5	110,583,824	322,730	0.0029	0.9971	96.53
12.5	108,095,037	3,413,034	0.0316	0.9684	96.25
13.5	101,566,531	422,505	0.0042	0.9958	93.21
14.5	100,325,557	557,071	0.0056	0.9944	92.82
15.5	96,151,173	433,305	0.0045	0.9955	92.31
16.5	94,551,113	1,197,088	0.0127	0.9873	91.89
17.5	89,769,851	982,379	0.0109	0.9891	90.73
18.5	85,462,226	1,502,582	0.0176	0.9824	89.74
19.5	82,362,470	191,877	0.0023	0.9977	88.16
20.5	74,199,415	294,252	0.0040	0.9960	87.95
21.5	71,881,223	514,999	0.0072	0.9928	87.60
22.5	69,862,547	144,879	0.0021	0.9979	86.98
23.5	67,391,464	440,175	0.0065	0.9935	86.80
24.5	65,728,204	260,527	0.0040	0.9960	86.23
25.5	62,719,185	151,030	0.0024	0.9976	85.89
26.5	57,356,931	105,811	0.0018	0.9982	85.68
27.5	53,186,508	168,510	0.0032	0.9968	85.52
28.5	41,231,200	190,900	0.0046	0.9954	85.25
29.5	39,547,236	421,487	0.0107	0.9893	84.86
30.5	36,456,419	568,844	0.0156	0.9844	83.95
31.5	30,551,375	168,964	0.0055	0.9945	82.64
32.5	27,635,476	286,817	0.0104	0.9896	82.19
33.5	21,466,577	405,063	0.0189	0.9811	81.33
34.5	19,520,062	369,389	0.0189	0.9811	79.80
35.5	18,732,856	488,479	0.0261	0.9739	78.29
36.5	17,344,030	629,535	0.0363	0.9637	76.25
37.5	15,171,494	740,976	0.0488	0.9512	73.48
38.5	14,120,330	539,481	0.0382	0.9618	69.89

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	12,077,557	308,346	0.0255	0.9745	67.22
40.5	11,843,553	701,041	0.0592	0.9408	65.50
41.5	11,247,090	421,841	0.0375	0.9625	61.63
42.5	10,864,578	686,428	0.0632	0.9368	59.32
43.5	10,069,529	1,108,246	0.1101	0.8899	55.57
44.5	8,802,902	450,717	0.0512	0.9488	49.45
45.5	8,167,459	277,049	0.0339	0.9661	46.92
46.5	7,845,875	36,876	0.0047	0.9953	45.33
47.5	7,673,656	130,586	0.0170	0.9830	45.12
48.5	6,995,569	440,135	0.0629	0.9371	44.35
49.5	6,276,595	223,735	0.0356	0.9644	41.56
50.5	6,082,672	17,752	0.0029	0.9971	40.08
51.5	5,437,079	105,627	0.0194	0.9806	39.96
52.5	4,539,062	55,017	0.0121	0.9879	39.18
53.5	4,293,358	9,285	0.0022	0.9978	38.71
54.5	3,804,264	57,986	0.0152	0.9848	38.62
55.5	3,683,363	52,280	0.0142	0.9858	38.04
56.5	3,399,147	90,268	0.0266	0.9734	37.50
57.5	3,247,223	67,850	0.0209	0.9791	36.50
58.5	2,851,228	6,527	0.0023	0.9977	35.74
59.5	2,346,317	6,006	0.0026	0.9974	35.66
60.5	1,972,350	15,778	0.0080	0.9920	35.56
61.5	1,758,765	21,796	0.0124	0.9876	35.28
62.5	1,403,987	8,171	0.0058	0.9942	34.84
63.5	1,379,810	22,766	0.0165	0.9835	34.64
64.5	1,331,235	27,885	0.0209	0.9791	34.07
65.5	1,254,231	14,972	0.0119	0.9881	33.35
66.5	1,219,285	12,774	0.0105	0.9895	32.96
67.5	1,193,842	6,930	0.0058	0.9942	32.61
68.5	1,192,308	2,941	0.0025	0.9975	32.42
69.5	1,233,352	41,548	0.0337	0.9663	32.34
70.5	1,163,816	395,776	0.3401	0.6599	31.25
71.5	761,134	49,252	0.0647	0.9353	20.62
72.5	713,547	2,834	0.0040	0.9960	19.29
73.5	738,884	50,108	0.0678	0.9322	19.21
74.5	678,814	26,029	0.0383	0.9617	17.91
75.5	607,624	2,664	0.0044	0.9956	17.22
76.5	602,439	1,773	0.0029	0.9971	17.15
77.5	599,615	2,739	0.0046	0.9954	17.10
78.5	588,909	251	0.0004	0.9996	17.02

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	564,908	11,805	0.0209	0.9791	17.01
80.5	567,413	828	0.0015	0.9985	16.66
81.5	565,568		0.0000	1.0000	16.63
82.5	565,568	0	0.0000	1.0000	16.63
83.5	563,919	45	0.0001	0.9999	16.63
84.5	563,874	3,532	0.0063	0.9937	16.63
85.5	556,100	6,565	0.0118	0.9882	16.53
86.5	550,723	1,847	0.0034	0.9966	16.33
87.5	539,899	16,749	0.0310	0.9690	16.28
88.5	362,153	46	0.0001	0.9999	15.77
89.5	353,270	0	0.0000	1.0000	15.77
90.5	213,665	87	0.0004	0.9996	15.77
91.5	206,706	6,521	0.0315	0.9685	15.76
92.5	165,601	9,902	0.0598	0.9402	15.27
93.5	88,539		0.0000	1.0000	14.35
94.5	86,557		0.0000	1.0000	14.35
95.5	85,585		0.0000	1.0000	14.35
96.5	81,157	260	0.0032	0.9968	14.35
97.5	80,897	28	0.0003	0.9997	14.31
98.5	80,869	2,594	0.0321	0.9679	14.30
99.5	78,276		0.0000	1.0000	13.84
100.5	78,276		0.0000	1.0000	13.84
101.5	78,276		0.0000	1.0000	13.84
102.5	78,276		0.0000	1.0000	13.84
103.5	78,276		0.0000	1.0000	13.84
104.5	78,276		0.0000	1.0000	13.84
105.5	78,276		0.0000	1.0000	13.84
106.5	78,276		0.0000	1.0000	13.84
107.5	29,200		0.0000	1.0000	13.84
108.5	24,996		0.0000	1.0000	13.84
109.5	24,996		0.0000	1.0000	13.84
110.5	24,996		0.0000	1.0000	13.84
111.5	24,996		0.0000	1.0000	13.84
112.5	24,996		0.0000	1.0000	13.84
113.5	24,996		0.0000	1.0000	13.84
114.5	24,996		0.0000	1.0000	13.84
115.5	24,996		0.0000	1.0000	13.84
116.5					13.84

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1983-2018

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	143,135,524	12,183	0.0001	0.9999	100.00
0.5	134,020,705	79,108	0.0006	0.9994	99.99
1.5	116,711,932	19,820	0.0002	0.9998	99.93
2.5	111,866,184	38,588	0.0003	0.9997	99.92
3.5	108,917,930	120,392	0.0011	0.9989	99.88
4.5	108,893,954	178,442	0.0016	0.9984	99.77
5.5	107,529,321	254,483	0.0024	0.9976	99.61
6.5	106,553,078	269,492	0.0025	0.9975	99.37
7.5	102,852,079	871,200	0.0085	0.9915	99.12
8.5	101,024,317	134,628	0.0013	0.9987	98.28
9.5	96,703,749	374,272	0.0039	0.9961	98.15
10.5	94,387,992	438,475	0.0046	0.9954	97.77
11.5	93,042,798	237,532	0.0026	0.9974	97.32
12.5	91,888,725	3,269,160	0.0356	0.9644	97.07
13.5	86,151,189	339,341	0.0039	0.9961	93.61
14.5	86,079,490	521,227	0.0061	0.9939	93.24
15.5	83,388,820	394,227	0.0047	0.9953	92.68
16.5	84,073,205	1,122,511	0.0134	0.9866	92.24
17.5	80,362,729	889,638	0.0111	0.9889	91.01
18.5	77,222,044	1,422,078	0.0184	0.9816	90.00
19.5	74,023,577	164,075	0.0022	0.9978	88.35
20.5	67,172,193	264,040	0.0039	0.9961	88.15
21.5	65,439,204	468,284	0.0072	0.9928	87.80
22.5	64,292,272	95,015	0.0015	0.9985	87.17
23.5	63,390,129	425,543	0.0067	0.9933	87.05
24.5	62,300,062	227,201	0.0036	0.9964	86.46
25.5	59,515,365	101,063	0.0017	0.9983	86.15
26.5	54,804,368	94,241	0.0017	0.9983	86.00
27.5	50,695,137	151,575	0.0030	0.9970	85.85
28.5	38,598,882	106,239	0.0028	0.9972	85.60
29.5	37,204,765	391,887	0.0105	0.9895	85.36
30.5	34,169,021	142,429	0.0042	0.9958	84.46
31.5	28,853,244	162,921	0.0056	0.9944	84.11
32.5	25,917,854	275,298	0.0106	0.9894	83.63
33.5	19,757,588	390,509	0.0198	0.9802	82.75
34.5	17,842,607	345,988	0.0194	0.9806	81.11
35.5	16,968,793	446,463	0.0263	0.9737	79.54
36.5	15,619,267	615,876	0.0394	0.9606	77.44
37.5	13,459,410	710,127	0.0528	0.9472	74.39
38.5	12,428,857	523,883	0.0422	0.9578	70.47

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1983-2018

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	10,332,852	248,197	0.0240	0.9760	67.50
40.5	10,174,732	649,184	0.0638	0.9362	65.87
41.5	9,592,488	415,706	0.0433	0.9567	61.67
42.5	9,213,472	682,066	0.0740	0.9260	59.00
43.5	8,442,405	1,098,397	0.1301	0.8699	54.63
44.5	7,134,279	449,865	0.0631	0.9369	47.52
45.5	6,499,076	242,195	0.0373	0.9627	44.53
46.5	6,185,907	34,075	0.0055	0.9945	42.87
47.5	6,052,714	58,995	0.0097	0.9903	42.63
48.5	5,450,265	439,317	0.0806	0.9194	42.22
49.5	4,746,200	206,237	0.0435	0.9565	38.81
50.5	4,546,044	4,827	0.0011	0.9989	37.13
51.5	3,998,616	105,465	0.0264	0.9736	37.09
52.5	3,256,869	21,643	0.0066	0.9934	36.11
53.5	3,050,456	6,367	0.0021	0.9979	35.87
54.5	2,874,416	55,257	0.0192	0.9808	35.79
55.5	3,221,102	52,280	0.0162	0.9838	35.11
56.5	2,961,472	11,009	0.0037	0.9963	34.54
57.5	2,991,619	67,850	0.0227	0.9773	34.41
58.5	2,603,796	6,160	0.0024	0.9976	33.63
59.5	2,104,794	2,064	0.0010	0.9990	33.55
60.5	1,733,109	13,457	0.0078	0.9922	33.51
61.5	1,520,085	21,796	0.0143	0.9857	33.25
62.5	1,168,697	8,121	0.0069	0.9931	32.78
63.5	1,154,960	17,836	0.0154	0.9846	32.55
64.5	1,090,878	27,877	0.0256	0.9744	32.05
65.5	1,038,561	9,609	0.0093	0.9907	31.23
66.5	1,010,693	2,902	0.0029	0.9971	30.94
67.5	990,929	6,930	0.0070	0.9930	30.85
68.5	995,998	2,941	0.0030	0.9970	30.63
69.5	1,038,766	41,548	0.0400	0.9600	30.54
70.5	1,014,621	382,042	0.3765	0.6235	29.32
71.5	709,339	49,252	0.0694	0.9306	18.28
72.5	665,339	2,834	0.0043	0.9957	17.01
73.5	690,705	50,108	0.0725	0.9275	16.94
74.5	637,121	26,029	0.0409	0.9591	15.71
75.5	575,925	1,464	0.0025	0.9975	15.07
76.5	571,940	1,773	0.0031	0.9969	15.03
77.5	569,117	2,739	0.0048	0.9952	14.98
78.5	558,410	251	0.0004	0.9996	14.91

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1983-2018

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	14.91
80.5	562,171	828	0.0015	0.9985	14.86
81.5	565,568		0.0000	1.0000	14.84
82.5	565,568	0	0.0000	1.0000	14.84
83.5	563,919	45	0.0001	0.9999	14.84
84.5	563,874	3,532	0.0063	0.9937	14.84
85.5	558,746	6,565	0.0117	0.9883	14.75
86.5	550,723	1,847	0.0034	0.9966	14.57
87.5	539,899	16,749	0.0310	0.9690	14.53
88.5	362,153	46	0.0001	0.9999	14.07
89.5	353,270	0	0.0000	1.0000	14.07
90.5	213,665	87	0.0004	0.9996	14.07
91.5	206,706	6,521	0.0315	0.9685	14.07
92.5	165,601	9,902	0.0598	0.9402	13.62
93.5	88,539		0.0000	1.0000	12.81
94.5	86,557		0.0000	1.0000	12.81
95.5	85,585		0.0000	1.0000	12.81
96.5	81,157	260	0.0032	0.9968	12.81
97.5	80,897	28	0.0003	0.9997	12.77
98.5	80,869	2,594	0.0321	0.9679	12.76
99.5	78,276		0.0000	1.0000	12.35
100.5	78,276		0.0000	1.0000	12.35
101.5	78,276		0.0000	1.0000	12.35
102.5	78,276		0.0000	1.0000	12.35
103.5	78,276		0.0000	1.0000	12.35
104.5	78,276		0.0000	1.0000	12.35
105.5	78,276		0.0000	1.0000	12.35
106.5	78,276		0.0000	1.0000	12.35
107.5	29,200		0.0000	1.0000	12.35
108.5	24,996		0.0000	1.0000	12.35
109.5	24,996		0.0000	1.0000	12.35
110.5	24,996		0.0000	1.0000	12.35
111.5	24,996		0.0000	1.0000	12.35
112.5	24,996		0.0000	1.0000	12.35
113.5	24,996		0.0000	1.0000	12.35
114.5	24,996		0.0000	1.0000	12.35
115.5	24,996		0.0000	1.0000	12.35
116.5					12.35

PLACEMENT BAND 1890-2018 EXPERIENCE BAND 1999-2018

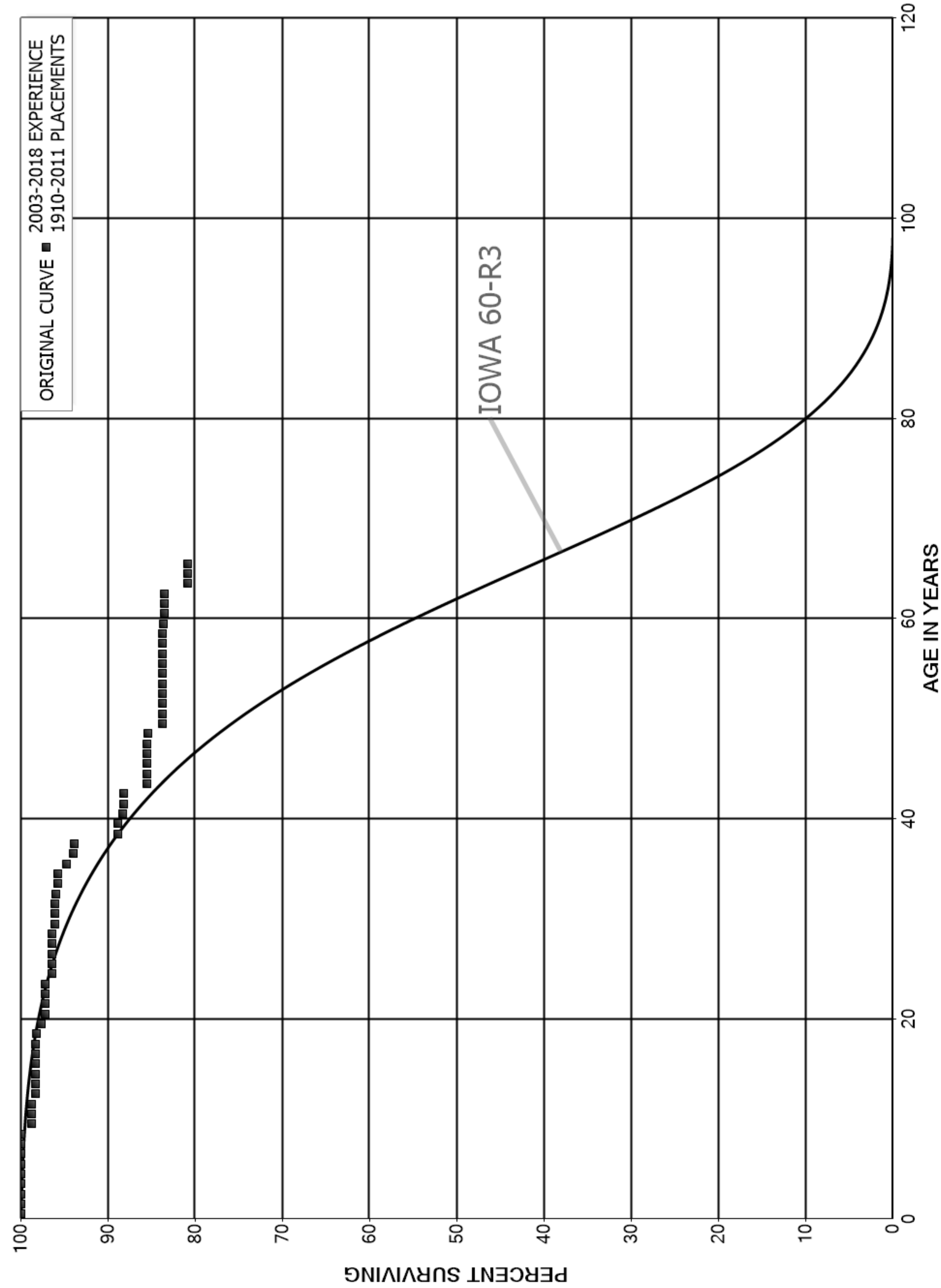
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	48,056,028	33	0.0000	1.0000	100.00
0.5	55,918,060	72,929	0.0013	0.9987	100.00
1.5	38,744,295	11,836	0.0003	0.9997	99.87
2.5	35,625,299	7,935	0.0002	0.9998	99.84
3.5	35,582,319	12,104	0.0003	0.9997	99.82
4.5	36,451,723	77,952	0.0021	0.9979	99.78
5.5	38,546,056	29,700	0.0008	0.9992	99.57
6.5	43,059,666	19,835	0.0005	0.9995	99.49
7.5	47,904,681	166,240	0.0035	0.9965	99.45
8.5	65,007,892	58,173	0.0009	0.9991	99.10
9.5	62,980,100	278,113	0.0044	0.9956	99.01
10.5	64,626,213	344,017	0.0053	0.9947	98.58
11.5	69,113,403	175,148	0.0025	0.9975	98.05
12.5	70,722,899	2,994,568	0.0423	0.9577	97.80
13.5	72,421,400	263,703	0.0036	0.9964	93.66
14.5	73,386,233	360,460	0.0049	0.9951	93.32
15.5	70,429,875	337,272	0.0048	0.9952	92.86
16.5	70,173,478	272,185	0.0039	0.9961	92.42
17.5	67,876,415	860,006	0.0127	0.9873	92.06
18.5	63,701,299	977,487	0.0153	0.9847	90.89
19.5	63,214,367	94,915	0.0015	0.9985	89.50
20.5	56,093,262	186,077	0.0033	0.9967	89.36
21.5	54,040,598	174,036	0.0032	0.9968	89.07
22.5	52,617,448	64,267	0.0012	0.9988	88.78
23.5	50,284,408	384,033	0.0076	0.9924	88.67
24.5	48,780,934	175,360	0.0036	0.9964	87.99
25.5	46,074,454	26,234	0.0006	0.9994	87.68
26.5	41,044,385	39,839	0.0010	0.9990	87.63
27.5	37,205,076	13,616	0.0004	0.9996	87.54
28.5	25,861,130	24,372	0.0009	0.9991	87.51
29.5	24,772,530	74,819	0.0030	0.9970	87.43
30.5	22,560,584	53,854	0.0024	0.9976	87.16
31.5	18,399,547	75,186	0.0041	0.9959	86.96
32.5	17,488,966	250,465	0.0143	0.9857	86.60
33.5	12,250,617	230,064	0.0188	0.9812	85.36
34.5	11,703,015	280,319	0.0240	0.9760	83.76
35.5	11,039,223	394,275	0.0357	0.9643	81.75
36.5	10,905,550	588,161	0.0539	0.9461	78.83
37.5	9,259,490	622,184	0.0672	0.9328	74.58
38.5	8,908,309	489,280	0.0549	0.9451	69.57

PLACEMENT BAND 1890-2018 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	8,098,840	240,008	0.0296	0.9704	65.75
40.5	8,453,634	636,552	0.0753	0.9247	63.80
41.5	8,110,238	339,758	0.0419	0.9581	59.00
42.5	8,282,349	649,340	0.0784	0.9216	56.52
43.5	7,562,628	1,092,721	0.1445	0.8555	52.09
44.5	6,561,765	449,865	0.0686	0.9314	44.57
45.5	6,178,073	242,195	0.0392	0.9608	41.51
46.5	5,861,868	23,912	0.0041	0.9959	39.88
47.5	5,853,257	58,995	0.0101	0.9899	39.72
48.5	5,252,117	428,328	0.0816	0.9184	39.32
49.5	4,544,949	206,120	0.0454	0.9546	36.11
50.5	4,337,670	4,827	0.0011	0.9989	34.48
51.5	3,817,204	105,334	0.0276	0.9724	34.44
52.5	2,931,327	21,472	0.0073	0.9927	33.49
53.5	2,699,075	5,905	0.0022	0.9978	33.24
54.5	2,217,738	2,975	0.0013	0.9987	33.17
55.5	2,150,086	44,819	0.0208	0.9792	33.12
56.5	1,881,861	10,706	0.0057	0.9943	32.43
57.5	1,813,218	4,254	0.0023	0.9977	32.25
58.5	1,490,498	732	0.0005	0.9995	32.17
59.5	1,011,120	2,064	0.0020	0.9980	32.16
60.5	681,205	5,577	0.0082	0.9918	32.09
61.5	475,612	8,683	0.0183	0.9817	31.83
62.5	141,995	8,057	0.0567	0.9433	31.25
63.5	134,266	12,275	0.0914	0.9086	29.48
64.5	83,649	27,694	0.3311	0.6689	26.78
65.5	43,798	271	0.0062	0.9938	17.91
66.5	46,705	2,902	0.0621	0.9379	17.80
67.5	44,281	2,769	0.0625	0.9375	16.70
68.5	197,703	2,941	0.0149	0.9851	15.65
69.5	261,285	39,375	0.1507	0.8493	15.42
70.5	456,290	6,566	0.0144	0.9856	13.10
71.5	455,005	49,252	0.1082	0.8918	12.91
72.5	424,458	2,834	0.0067	0.9933	11.51
73.5	546,474	11,848	0.0217	0.9783	11.43
74.5	529,622	26,029	0.0491	0.9509	11.19
75.5	463,798	1,464	0.0032	0.9968	10.64
76.5	467,418	1,773	0.0038	0.9962	10.60
77.5	465,155	2,739	0.0059	0.9941	10.56
78.5	457,665	251	0.0005	0.9995	10.50

PLACEMENT BAND 1890-2018 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	452,692	1,552	0.0034	0.9966	10.49
80.5	439,230	828	0.0019	0.9981	10.46
81.5	437,385		0.0000	1.0000	10.44
82.5	437,403	0	0.0000	1.0000	10.44
83.5	439,261	45	0.0001	0.9999	10.44
84.5	445,818	3,532	0.0079	0.9921	10.44
85.5	442,414	6,565	0.0148	0.9852	10.35
86.5	450,874	1,847	0.0041	0.9959	10.20
87.5	487,608	16,749	0.0343	0.9657	10.16
88.5	315,145	46	0.0001	0.9999	9.81
89.5	306,290	0	0.0000	1.0000	9.81
90.5	173,173	87	0.0005	0.9995	9.81
91.5	176,208	6,521	0.0370	0.9630	9.80
92.5	135,102	9,902	0.0733	0.9267	9.44
93.5	58,040		0.0000	1.0000	8.75
94.5	56,058		0.0000	1.0000	8.75
95.5	55,087		0.0000	1.0000	8.75
96.5	75,915	260	0.0034	0.9966	8.75
97.5	80,897	28	0.0003	0.9997	8.72
98.5	80,869	2,594	0.0321	0.9679	8.72
99.5	78,276		0.0000	1.0000	8.44
100.5	78,276		0.0000	1.0000	8.44
101.5	78,276		0.0000	1.0000	8.44
102.5	78,276		0.0000	1.0000	8.44
103.5	78,276		0.0000	1.0000	8.44
104.5	78,276		0.0000	1.0000	8.44
105.5	78,276		0.0000	1.0000	8.44
106.5	78,276		0.0000	1.0000	8.44
107.5	29,200		0.0000	1.0000	8.44
108.5	24,996		0.0000	1.0000	8.44
109.5	24,996		0.0000	1.0000	8.44
110.5	24,996		0.0000	1.0000	8.44
111.5	24,996		0.0000	1.0000	8.44
112.5	24,996		0.0000	1.0000	8.44
113.5	24,996		0.0000	1.0000	8.44
114.5	24,996		0.0000	1.0000	8.44
115.5	24,996		0.0000	1.0000	8.44
116.5					8.44


ORIGINAL CURVE ■ 2003-2018 EXPERIENCE
1910-2011 PLACEMENTS
IOWA 60-R3
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
20
40
60
80
100
120

PLACEMENT BAND 1910-2011 EXPERIENCE BAND 2003-2018

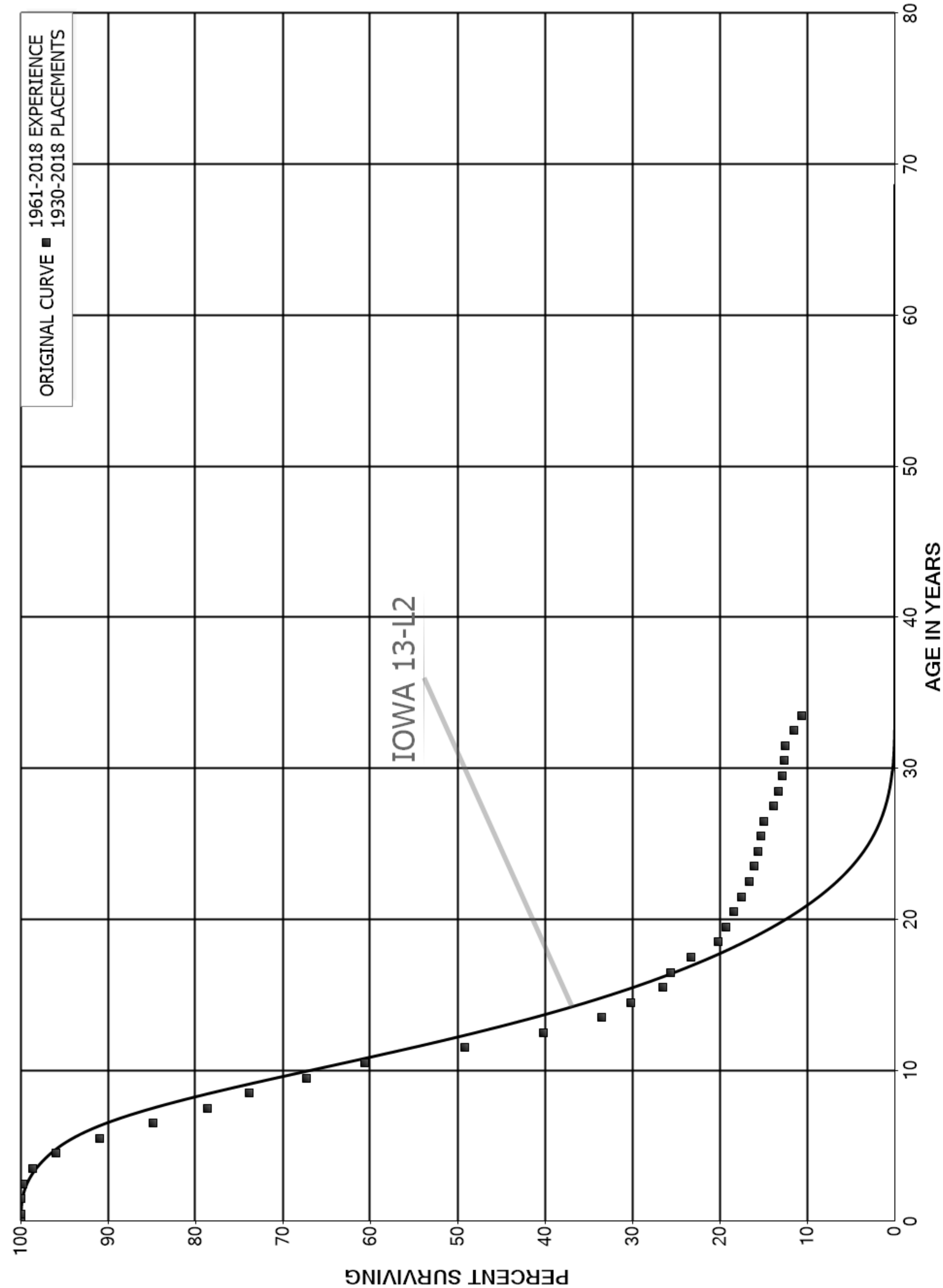
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,016,144		0.0000	1.0000	100.00
0.5	1,090,414		0.0000	1.0000	100.00
1.5	1,237,413		0.0000	1.0000	100.00
2.5	1,280,857		0.0000	1.0000	100.00
3.5	1,622,268		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

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

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

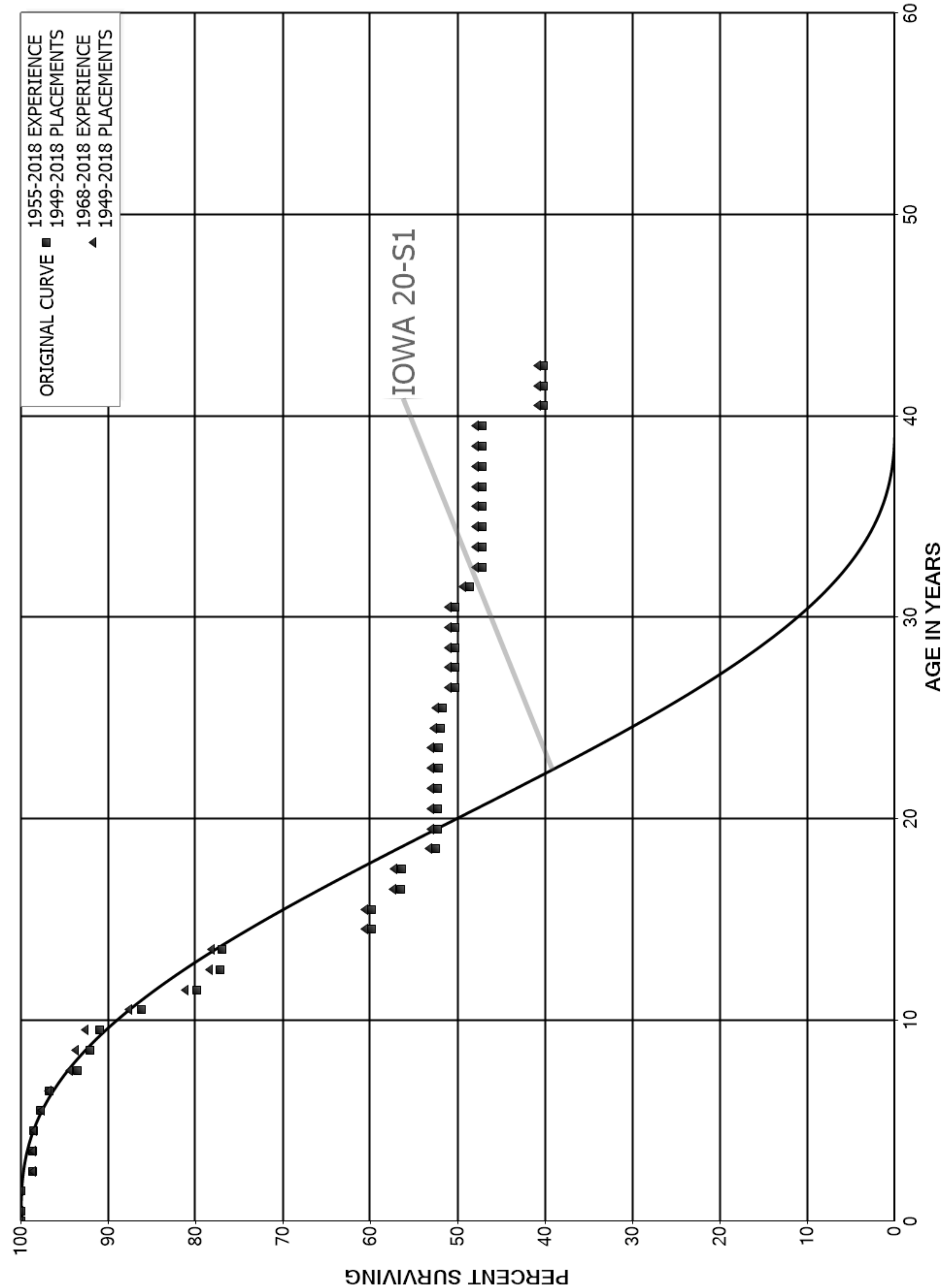

ORIGINAL CURVE ■ 1961-2018 EXPERIENCE
1930-2018 PLACEMENTS
IOWA 13-L2
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100

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

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					


ORIGINAL CURVE ■ 1955-2018 EXPERIENCE 1949-2018 PLACEMENTS
▲ 1968-2018 EXPERIENCE 1949-2018 PLACEMENTS
IOWA 20-S1
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100

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

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

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 1968-2018

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	4,611,670		0.0000	1.0000	100.00
0.5	4,472,966	3,337	0.0007	0.9993	100.00
1.5	4,391,316	61,869	0.0141	0.9859	99.93
2.5	4,364,315	684	0.0002	0.9998	98.52
3.5	3,760,538	5,364	0.0014	0.9986	98.50
4.5	3,894,044	32,269	0.0083	0.9917	98.36
5.5	3,894,529	32,252	0.0083	0.9917	97.55
6.5	3,875,833	98,436	0.0254	0.9746	96.74
7.5	3,786,872	26,518	0.0070	0.9930	94.28
8.5	3,824,547	45,188	0.0118	0.9882	93.62
9.5	3,725,128	199,708	0.0536	0.9464	92.52
10.5	3,555,064	264,626	0.0744	0.9256	87.56
11.5	3,604,512	122,712	0.0340	0.9660	81.04
12.5	3,544,248	11,185	0.0032	0.9968	78.28
13.5	3,534,900	796,019	0.2252	0.7748	78.03
14.5	3,112,790		0.0000	1.0000	60.46
15.5	3,609,407	187,551	0.0520	0.9480	60.46
16.5	3,507,724	11,101	0.0032	0.9968	57.32
17.5	3,417,542	234,564	0.0686	0.9314	57.14
18.5	3,177,345	13,695	0.0043	0.9957	53.22
19.5	3,163,347		0.0000	1.0000	52.99
20.5	2,911,238		0.0000	1.0000	52.99
21.5	2,691,109	2,716	0.0010	0.9990	52.99
22.5	2,700,992		0.0000	1.0000	52.93
23.5	2,554,571	13,635	0.0053	0.9947	52.93
24.5	2,380,874	12,599	0.0053	0.9947	52.65
25.5	2,212,027	60,100	0.0272	0.9728	52.37
26.5	2,086,329		0.0000	1.0000	50.95
27.5	1,416,342		0.0000	1.0000	50.95
28.5	1,404,928		0.0000	1.0000	50.95
29.5	1,427,727		0.0000	1.0000	50.95
30.5	1,070,297	35,353	0.0330	0.9670	50.95
31.5	540,481	15,633	0.0289	0.9711	49.27
32.5	444,895		0.0000	1.0000	47.84
33.5	348,352		0.0000	1.0000	47.84
34.5	323,796		0.0000	1.0000	47.84
35.5	317,464		0.0000	1.0000	47.84
36.5	316,395		0.0000	1.0000	47.84
37.5	284,189		0.0000	1.0000	47.84
38.5	284,189		0.0000	1.0000	47.84

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 1968-2018

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	47.84
40.5	214,622		0.0000	1.0000	40.70
41.5	207,163		0.0000	1.0000	40.70
42.5	142,833		0.0000	1.0000	40.70
43.5	142,206		0.0000	1.0000	40.70
44.5	95,805		0.0000	1.0000	40.70
45.5	86,801		0.0000	1.0000	40.70
46.5	82,900		0.0000	1.0000	40.70
47.5	76,594		0.0000	1.0000	40.70
48.5	76,594		0.0000	1.0000	40.70
49.5	27,605		0.0000	1.0000	40.70
50.5	27,605		0.0000	1.0000	40.70
51.5	27,605		0.0000	1.0000	40.70
52.5	27,605		0.0000	1.0000	40.70
53.5	540		0.0000	1.0000	40.70
54.5	540		0.0000	1.0000	40.70
55.5	540		0.0000	1.0000	40.70
56.5	540		0.0000	1.0000	40.70
57.5	540		0.0000	1.0000	40.70
58.5	540		0.0000	1.0000	40.70
59.5	540		0.0000	1.0000	40.70
60.5	540		0.0000	1.0000	40.70
61.5					40.70

PART VIII. NET SALVAGE STATISTICS

2008	16		0	1,500		1,500	
2009							
2010							
2011							
2012		786		2,000		1,214	
2013		1,000-				1,000	
2014		10,350-				10,350	
2015							
2016	3,809,628		0		0		0
2017							
2018							
TOTAL	3,809,644	10,564-	0	3,500	0	14,064	0

THREE-YEAR MOVING AVERAGES

08-10	5		0	500		500	
09-11							
10-12		262		667		405	
11-13		71-		667		738	
12-14		3,521-		667		4,188	
13-15		3,783-				3,783	
14-16	1,269,876	3,450-	0		0	3,450	0
15-17	1,269,876		0		0		0
16-18	1,269,876		0		0		0

FIVE-YEAR AVERAGE

14-18	761,926	2,070-	0		0	2,070	0

2007	4,045	650	16	0	650-	16-
2008						
2009	4,413	4,486-	102-	0	4,486	102
2010	17,397	373-	2-	0	373	2
2011						
2012						
2013	4,028		0	0		0
2014	6,451		0	0		0
2015						
2016	3,506		0	0		0
2017	2,390	1,522	64	0	1,522-	64-
2018		7			7-	
TOTAL	42,231	2,680-	6-	0	2,680	6

THREE-YEAR MOVING AVERAGES

07-09	2,820	1,279-	45-	0	1,279	45
08-10	7,270	1,620-	22-	0	1,620	22
09-11	7,270	1,620-	22-	0	1,620	22
10-12	5,799	124-	2-	0	124	2
11-13	1,343		0	0		0
12-14	3,493		0	0		0
13-15	3,493		0	0		0
14-16	3,319		0	0		0
15-17	1,965	507	26	0	507-	26-
16-18	1,965	510	26	0	510-	26-

FIVE-YEAR AVERAGE

14-18	2,469	306	12	0	306-	12-

2005	41,563	76,109	183		0	76,109-	183-
2006	8,670,043	14,750	0		0	14,750-	0
2007	3,461,034	122,824	4		0	122,824-	4-
2008	12,362,952	87,950	1		0	87,950-	1-
2009	1,501,512	259,275	17	830	0	258,445-	17-
2010	1,998,946	82,192	4		0	82,192-	4-
2011	1,003,255	130,253	13		0	130,253-	13-
2012	429,405	155,301	36		0	155,301-	36-
2013	1,810,105	168,040-	9-		0	168,040	9
2014	2,789,757	1,499,432	54		0	1,499,432-	54-
2015	3,798,543	1,210,120	32	9,208	0	1,200,912-	32-
2016	3,552,274	564,602	16		0	564,602-	16-
2017	3,382,670	1,611,823	48		0	1,611,823-	48-
2018	1,949,884	1,013,998	52		0	1,013,998-	52-
TOTAL	46,751,943	6,660,589	14	10,038	0	6,650,551-	14-
THREE-YEAR MOVING AVERAGES							
05-07	4,057,547	71,228	2		0	71,228-	2-
06-08	8,164,676	75,174	1		0	75,174-	1-
07-09	5,775,166	156,683	3	277	0	156,406-	3-
08-10	5,287,804	143,139	3	277	0	142,862-	3-
09-11	1,501,238	157,240	10	277	0	156,963-	10-
10-12	1,143,869	122,582	11		0	122,582-	11-
11-13	1,080,921	39,171	4		0	39,171-	4-
12-14	1,676,422	495,564	30		0	495,564-	30-
13-15	2,799,468	847,171	30	3,069	0	844,102-	30-
14-16	3,380,191	1,091,385	32	3,069	0	1,088,315-	32-
15-17	3,577,829	1,128,848	32	3,069	0	1,125,779-	31-
16-18	2,961,609	1,063,474	36		0	1,063,474-	36-
FIVE-YEAR AVERAGE							
14-18	3,094,626	1,179,995	38	1,842	0	1,178,153-	38-

2015	813,565	0	0	0
2016				
2017				
2018				
TOTAL	813,565	0	0	0

THREE-YEAR MOVING AVERAGES

15-17	271,188	0	0	0
16-18				

2005		8,975				8,975-	
2006	1,004,015	50,872	5		0	50,872-	5-
2007	725,903	140,665	19		0	140,665-	19-
2008	621,771	53,831	9	1,089	0	52,742-	8-
2009	1,684,050	2,577,918	153	90,216	5	2,487,701-	148-
2010	480,565	2,090,934	435	61,254	13	2,029,681-	422-
2011	266,438		0		0		0
2012	1,449,579		0		0		0
2013	3,389,026		0		0		0
2014	2,957,886	58,112	2		0	58,112-	2-
2015	4,970,276	352,571	7		0	352,571-	7-
2016	5,111,844		0		0		0
2017	4,549,228	504,733	11		0	504,733-	11-
2018	3,276,471	642,070	20		0	642,070-	20-
TOTAL	30,487,052	6,480,681	21	152,559	1	6,328,121-	21-

THREE-YEAR MOVING AVERAGES

05-07	576,639	66,837	12		0	66,837-	12-
06-08	783,896	81,789	10	363	0	81,426-	10-
07-09	1,010,575	924,138	91	30,435	3	893,703-	88-
08-10	928,795	1,574,228	169	50,853	5	1,523,375-	164-
09-11	810,351	1,556,284	192	50,490	6	1,505,794-	186-
10-12	732,194	696,978	95	20,418	3	676,560-	92-
11-13	1,701,681		0		0		0
12-14	2,598,831	19,371	1		0	19,371-	1-
13-15	3,772,396	136,894	4		0	136,894-	4-
14-16	4,346,668	136,894	3		0	136,894-	3-
15-17	4,877,116	285,768	6		0	285,768-	6-
16-18	4,312,514	382,268	9		0	382,268-	9-

FIVE-YEAR AVERAGE

14-18	4,173,141	311,497	7		0	311,497-	7-

2005	10	211			0	211-	
2006	548,170	3,664	1		0	3,664-	1-
2007	1,048,991	172,320	16		0	172,320-	16-
2008	1,324,657	262,700	20	8,926	1	253,774-	19-
2009	628,313	1,671,367	266	27,430	4	1,643,937-	262-
2010	628,375	1,190,107	189	41,699	7	1,148,408-	183-
2011	405,429	1,342,123	331	1,091	0	1,341,032-	331-
2012	2,775,295	2,609,483	94		0	2,609,483-	94-
2013	2,627,975	5,466,856	208		0	5,466,856-	208-
2014	1,531,121	3,115,421	203		0	3,115,421-	203-
2015	3,996,212	690,753	17		0	690,753-	17-
2016	2,574,355	2,435,839	95		0	2,435,839-	95-
2017	3,448,163	1,704,842	49		0	1,704,842-	49-
2018	2,568,567	224,883	9		0	224,883-	9-
TOTAL	24,105,635	20,890,569	87	79,146	0	20,811,424-	86-

THREE-YEAR MOVING AVERAGES

05-07	532,390	58,732	11		0	58,732-	11-
06-08	973,939	146,228	15	2,975	0	143,253-	15-
07-09	1,000,654	702,129	70	12,119	1	690,011-	69-
08-10	860,448	1,041,391	121	26,018	3	1,015,373-	118-
09-11	554,039	1,401,199	253	23,407	4	1,377,792-	249-
10-12	1,269,700	1,713,904	135	14,263	1	1,699,641-	134-
11-13	1,936,233	3,139,487	162	364	0	3,139,124-	162-
12-14	2,311,464	3,730,587	161		0	3,730,587-	161-
13-15	2,718,436	3,091,010	114		0	3,091,010-	114-
14-16	2,700,563	2,080,671	77		0	2,080,671-	77-
15-17	3,339,577	1,610,478	48		0	1,610,478-	48-
16-18	2,863,695	1,455,188	51		0	1,455,188-	51-

FIVE-YEAR AVERAGE

14-18	2,823,684	1,634,348	58		0	1,634,348-	58-

2013	1,573	0	0	0
2014				
2015				
2016				
2017				
2018				
TOTAL	1,573	0	0	0
THREE-YEAR MOVING AVERAGES				
13-15	524	0	0	0
14-16				
15-17				
16-18				
FIVE-YEAR AVERAGE				
14-18				

2007		7,913				7,913-	
2008							
2009	4,217	22,430	532	807	19	21,623-	513-
2010		31,698		3,532		28,167-	
2011							
2012	18,572		0		0		0
2013	34,697		0		0		0
2014		548				548-	
2015	144,416	39,040	27		0	39,040-	27-
2016	912,705	73,779	8		0	73,779-	8-
2017	118,496	54,686	46		0	54,686-	46-
2018	196,995	37,067	19		0	37,067-	19-
TOTAL	1,430,098	267,161	19	4,339	0	262,823-	18-

THREE-YEAR MOVING AVERAGES

07-09	1,406	10,114	719	269	19	9,845-	700-
08-10	1,406	18,043		1,446	103	16,597-	
09-11	1,406	18,043		1,446	103	16,597-	
10-12	6,191	10,566	171	1,177	19	9,389-	152-
11-13	17,756		0		0		0
12-14	17,756	183	1		0	183-	1-
13-15	59,704	13,196	22		0	13,196-	22-
14-16	352,374	37,789	11		0	37,789-	11-
15-17	391,872	55,835	14		0	55,835-	14-
16-18	409,399	55,177	13		0	55,177-	13-

FIVE-YEAR AVERAGE

14-18	274,522	41,024	15		0	41,024-	15-

2003	9,370,448		0		0		0
2004		16,303				16,303-	
2005	33,614	45,051	134		0	45,051-	134-
2006	611,919	78,407	13	1,197,239	196	1,118,832	183
2007	89,344	350,502	392		0	350,502-	392-
2008	799,084	149,027	19	634,432	79	485,405	61
2009	1,298	134	10		0	134-	10-
2010	167,519	22,526	13		0	22,526-	13-
2011	3,565	10,552	296		0	10,552-	296-
2012		189,084				189,084-	
2013	63,996	267,059	417		0	267,059-	417-
2014	98,532	164,541	167		0	164,541-	167-
2015		6,749				6,749-	
2016	1,262,332		0		0		0
2017							
2018	2,244,177	561,064	25		0	561,064-	25-
TOTAL	14,745,828	1,860,999	13	1,831,671	12	29,327-	0

THREE-YEAR MOVING AVERAGES

03-05	3,134,687	20,451	1		0	20,451-	1-
04-06	215,178	46,587	22	399,080	185	352,493	164
05-07	244,959	157,987	64	399,080	163	241,093	98
06-08	500,116	192,645	39	610,557	122	417,912	84
07-09	296,576	166,554	56	211,477	71	44,923	15
08-10	322,634	57,229	18	211,477	66	154,248	48
09-11	57,461	11,071	19		0	11,071-	19-
10-12	57,028	74,054	130		0	74,054-	130-
11-13	22,520	155,565	691		0	155,565-	691-
12-14	54,176	206,895	382		0	206,895-	382-
13-15	54,176	146,116	270		0	146,116-	270-
14-16	453,621	57,097	13		0	57,097-	13-
15-17	420,777	2,250	1		0	2,250-	1-
16-18	1,168,836	187,021	16		0	187,021-	16-

FIVE-YEAR AVERAGE

14-18	721,008	146,471	20		0	146,471-	20-

2006	144,779	7,747	5	354,272	245	346,525	239
2007	2,456	24,645			0	24,645-	
2008	251,509	84,068	33	191,796	76	107,727	43
2009							
2010	57,736		0		0		0
2011							
2012							
2013							
2014							
2015							
2016	14,667		0		0		0
2017							
2018	5,338		0		0		0
TOTAL	476,485	116,461	24	546,068	115	429,607	90

THREE-YEAR MOVING AVERAGES

06-08	132,914	38,820	29	182,023	137	143,202	108
07-09	84,655	36,238	43	63,932	76	27,694	33
08-10	103,082	28,023	27	63,932	62	35,909	35
09-11	19,245		0		0		0
10-12	19,245		0		0		0
11-13							
12-14							
13-15							
14-16	4,889		0		0		0
15-17	4,889		0		0		0
16-18	6,669		0		0		0

FIVE-YEAR AVERAGE

14-18	4,001		0		0		0

2004	754,391		0		0		0
2005	926,512		0		0		0
2006	304,439		0		0		0
2007	53,587		0		0		0
2008	20,794	39,572-	190-		0	39,572	190
2009	149,263	8,209-	5-		0	8,209	5
2010		9,416-				9,416	
2011	4,729	156	3		0	156-	3-
2012		122				122-	
2013							
2014							
2015	32,145		0	2,582	8	2,582	8
2016							
2017	120	1,619-			0	1,619	
2018							
TOTAL	2,245,980	58,539-	3-	2,582	0	61,121	3

THREE-YEAR MOVING AVERAGES

04-06	661,781		0		0		0
05-07	428,179		0		0		0
06-08	126,273	13,191-	10-		0	13,191	10
07-09	74,548	15,927-	21-		0	15,927	21
08-10	56,685	19,066-	34-		0	19,066	34
09-11	51,331	5,823-	11-		0	5,823	11
10-12	1,576	3,046-	193-		0	3,046	193
11-13	1,576	92	6		0	92-	6-
12-14		41				41-	
13-15	10,715		0	861	8	861	8
14-16	10,715		0	861	8	861	8
15-17	10,755	540-	5-	861	8	1,400	13
16-18	40	540-			0	540	

FIVE-YEAR AVERAGE

14-18	6,453	324-	5-	516	8	840	13

2004	52,288	64,029-	122-		0	64,029	122
2005	90,451		0		0		0
2006	766,340		0		0		0
2007	10,500		0		0		0
2008	10,500	1,668	16	8,707	83	7,039	67
2009	18,063		0		0		0
2010							
2011							
2012							
2013	141,777		0		0		0
2014							
2015							
2016							
2017		581-				581	
2018							
TOTAL	1,089,920	62,942-	6-	8,707	1	71,649	7
THREE-YEAR MOVING AVERAGES							
04-06	303,027	21,343-	7-		0	21,343	7
05-07	289,097		0		0		0
06-08	262,447	556	0	2,902	1	2,346	1
07-09	13,021	556	4	2,902	22	2,346	18
08-10	9,521	556	6	2,902	30	2,346	25
09-11	6,021		0		0		0
10-12							
11-13	47,259		0		0		0
12-14	47,259		0		0		0
13-15	47,259		0		0		0
14-16							
15-17		194-				194	
16-18		194-				194	
FIVE-YEAR AVERAGE							
14-18		116-				116	

PART IX. DETAILED DEPRECIATION CALCULATIONS

SURVIVOR CURVE.. 7-SQUARE
NET SALVAGE PERCENT.. 0

1994	278,115.70	278,116	278,116			
1997	5,063.42	5,063	5,063			
2000	1.35	1	1			
2001	1,868.77	1,869	1,869			
2002	19,763.63	19,764	19,764			
2003	1,580,374.23	1,580,374	1,580,374			
2004	387,293.77	387,294	387,294			
2005	127,285.95	127,286	127,286			
2006	202,473.17	202,473	202,473			
2007	1,116,931.58	1,116,932	1,116,932			
2008	101,474.20	101,474	101,474			
2009	339,691.54	339,692	339,692			
2010	173,134.17	173,134	173,134			
2011	460,007.30	460,007	460,007			
2012	212,867.24	197,662	194,881	17,986	0.50	17,986
2013	351,531.24	276,202	272,316	79,215	1.50	52,810
2014	979,512.40	629,689	620,831	358,681	2.50	143,472
2015	405,540.43	202,770	199,917	205,623	3.50	58,749
2016	654,691.32	233,816	230,527	424,164	4.50	94,259
2017	693,485.98	148,607	146,517	546,969	5.50	99,449
2018	1,472,508.47	105,181	103,701	1,368,807	6.50	210,586
	9,563,615.86	6,587,406	6,562,169	3,001,447		677,311

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.4 7.08

SURVIVOR CURVE.. IOWA 75-R3
NET SALVAGE PERCENT.. 0

1913	1,091.41	1,015	913	178	5.23	34
1914	548.39	508	457	91	5.49	17
1924	17,833.21	15,902	14,299	3,534	8.12	435
1925	14,351.46	12,746	11,461	2,890	8.39	344
1926	290,497.84	256,879	230,989	59,509	8.68	6,856
1927	81,447.52	71,706	64,479	16,969	8.97	1,892
1928	41,738.62	36,585	32,898	8,841	9.26	955
1929	58,509.45	51,044	45,899	12,610	9.57	1,318
1930	644,339.66	559,461	503,074	141,266	9.88	14,298
1931	242,658.90	209,657	188,526	54,133	10.20	5,307
1932	293,237.98	252,067	226,662	66,576	10.53	6,323
1933	6,005.18	5,135	4,617	1,388	10.87	128
1934	223.62	190	171	53	11.22	5
1935	5,059.47	4,278	3,847	1,212	11.59	105
1936	22,579.05	18,978	17,065	5,514	11.96	461
1937	10,829.84	9,048	8,136	2,694	12.34	218
1938	225,932.94	187,554	168,651	57,282	12.74	4,496
1939	4,429.88	3,654	3,286	1,144	13.14	87
1940	44,003.34	36,048	32,415	11,588	13.56	855
1941	69,643.10	56,643	50,934	18,709	14.00	1,336
1942	14,482.05	11,694	10,515	3,967	14.44	275
1943	40,384.28	32,361	29,099	11,285	14.90	757
1944	6,021.52	4,788	4,305	1,717	15.37	112
1945	5,518.07	4,352	3,913	1,605	15.85	101
1946	3,763.69	2,943	2,646	1,118	16.35	68
1947	9,489.29	7,357	6,616	2,873	16.85	171
1948	28,522.24	21,916	19,707	8,815	17.37	507
1949	82,830.02	63,050	56,695	26,135	17.91	1,459
1950	238,716.69	179,992	161,851	76,866	18.45	4,166
1951	122,985.91	91,813	82,559	40,427	19.01	2,127
1952	21,431.69	15,837	14,241	7,191	19.58	367
1953	790,554.31	578,053	519,792	270,762	20.16	13,431
1954	96,461.23	69,773	62,741	33,720	20.75	1,625
1955	245,346.10	175,472	157,787	87,559	21.36	4,099
1956	187,977.24	132,887	119,494	68,483	21.98	3,116
1957	1,015,494.26	709,495	637,986	377,508	22.60	16,704
1958	272,428.39	188,011	169,062	103,366	23.24	4,448
1959	645,012.67	439,557	395,255	249,758	23.89	10,454
1960	140,375.03	94,426	84,909	55,466	24.55	2,259
1961	1,262,657.31	838,064	753,597	509,060	25.22	20,185
1962	2,579,282.00	1,688,914	1,518,692	1,060,590	25.89	40,965
1963	220,472.34	142,337	127,991	92,481	26.58	3,479
1964	1,149,925.73	731,663	657,920	492,006	27.28	18,035

SURVIVOR CURVE.. IOWA 75-R3
NET SALVAGE PERCENT.. 0

1965	1,380,518.73	865,489	778,258	602,261	27.98	21,525
1966	644,070.65	397,604	357,530	286,541	28.70	9,984
1967	519,738.64	315,861	284,026	235,713	29.42	8,012
1968	211,188.23	126,291	113,562	97,626	30.15	3,238
1969	2,859,752.09	1,681,906	1,512,390	1,347,362	30.89	43,618
1970	800,182.99	462,610	415,984	384,199	31.64	12,143
1971	1,232,564.79	700,257	629,680	602,885	32.39	18,613
1972	113,587.84	63,382	56,994	56,594	33.15	1,707
1973	293,468.11	160,741	144,540	148,928	33.92	4,391
1974	344,840.68	185,293	166,618	178,223	34.70	5,136
1975	60,852.41	32,057	28,826	32,026	35.49	902
1976	1,080,808.29	557,989	501,750	579,058	36.28	15,961
1977	272,785.58	137,920	124,019	148,767	37.08	4,012
1978	96,459.71	47,741	42,929	53,531	37.88	1,413
1979	256,859.90	124,320	111,790	145,070	38.70	3,749
1980	19,275.93	9,119	8,200	11,076	39.52	280
1981	8,827,886.98	4,079,631	3,668,453	5,159,434	40.34	127,899
1982	747,681.13	337,152	303,171	444,510	41.18	10,794
1983	251,376.93	110,538	99,397	151,980	42.02	3,617
1984	533,449.25	228,599	205,559	327,890	42.86	7,650
1985	29,103.71	12,138	10,915	18,189	43.72	416
1986	73,388.49	29,776	26,775	46,613	44.57	1,046
1987	255,808.86	100,822	90,660	165,149	45.44	3,634
1988	977,376.62	373,876	336,194	641,183	46.31	13,845
1989	96,769.40	35,895	32,277	64,492	47.18	1,367
1990	136,454.99	48,997	44,059	92,396	48.07	1,922
1991	65,312.19	22,685	20,399	44,913	48.95	918
1992	239,848.98	80,429	72,323	167,526	49.85	3,361
1993	28,227.92	9,131	8,211	20,017	50.74	395
1995	3,692.07	1,105	994	2,698	52.56	51
1998	8,134.27	2,135	1,920	6,214	55.31	112
1999	966,980.28	241,871	217,493	749,487	56.24	13,327
2003	5,304.93	1,062	955	4,350	59.99	73
2005	58,596.13	10,243	9,211	49,385	61.89	798
2008	139,834.61	19,092	17,168	122,667	64.76	1,894
2009	197.83	24	22	176	65.73	3
2010	3,318.40	368	331	2,987	66.69	45

SURVIVOR CURVE.. IOWA 75-R3
NET SALVAGE PERCENT.. 0

2011	2,921.75	286	257	2,665	67.66	39
2016	5,232,714.10	171,633	154,333	5,078,381	72.54	70,008
2017	43,013.31	849	763	42,250	73.52	575
	40,169,440.62	19,800,770	17,805,088	22,364,353		612,853

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.5   1.53

SURVIVOR CURVE.. IOWA 75-R4
NET SALVAGE PERCENT.. 0

1926	16,606.36	15,484	16,606			
1931	160.46	147	160			
1938	5,041.23	4,456	5,041			
1940	2,905.23	2,538	2,905			
1941	43.16	37	43			
1942	44.93	39	45			
1944	193.21	164	193			
1945	680.13	574	680			
1947	4,315.93	3,583	4,316			
1948	100.19	82	100			
1949	25,553.88	20,832	25,554			
1950	19,035.27	15,365	19,035			
1951	19,400.59	15,502	19,355	46	15.07	3
1952	50.21	40	50			
1953	24,469.65	19,138	23,894	576	16.34	35
1954	127,806.58	98,837	123,401	4,406	17.00	259
1955	5,389.30	4,120	5,144	245	17.67	14
1956	49,631.14	37,488	46,805	2,826	18.35	154
1957	29,188.42	21,782	27,196	1,992	19.03	105
1958	81,131.47	59,788	74,647	6,484	19.73	329
1959	80,929.64	58,874	73,506	7,424	20.44	363
1960	55,202.11	39,635	49,486	5,716	21.15	270
1961	70,501.38	49,934	62,344	8,157	21.88	373
1962	114,792.01	80,186	100,115	14,677	22.61	649
1963	422,149.63	290,663	362,902	59,248	23.36	2,536
1964	254,195.15	172,479	215,346	38,849	24.11	1,611
1965	327,282.50	218,713	273,070	54,212	24.88	2,179
1966	446,901.82	294,061	367,145	79,757	25.65	3,109
1967	453,123.16	293,384	366,299	86,824	26.44	3,284
1968	108,839.98	69,323	86,552	22,288	27.23	819
1969	591,114.22	370,114	462,099	129,015	28.04	4,601
1970	417,100.57	256,654	320,441	96,660	28.85	3,350
1971	275,784.97	166,649	208,067	67,718	29.68	2,282
1972	476,103.78	282,425	352,617	123,487	30.51	4,047
1973	190,634.92	110,950	138,525	52,110	31.35	1,662
1974	310,749.05	177,292	221,355	89,394	32.21	2,775
1975	526,773.67	294,503	367,696	159,078	33.07	4,810
1976	115,287.97	63,117	78,804	36,484	33.94	1,075
1977	619,673.66	332,065	414,594	205,080	34.81	5,891
1978	88,558.34	46,405	57,938	30,620	35.70	858
1979	233,800.69	119,736	149,494	84,307	36.59	2,304
1980	41,914.59	20,963	26,173	15,742	37.49	420
1981	430,510.54	210,089	262,303	168,208	38.40	4,380

SURVIVOR CURVE.. IOWA 75-R4
NET SALVAGE PERCENT.. 0

1982	651,636.76	310,003	387,049	264,588	39.32	6,729
1983	33,452.50	15,504	19,357	14,096	40.24	350
1984	230,195.01	103,864	129,678	100,517	41.16	2,442
1985	170,747.18	74,902	93,518	77,229	42.10	1,834
1986	471,698.52	201,005	250,961	220,738	43.04	5,129
1987	1,971,877.13	815,568	1,018,263	953,614	43.98	21,683
1988	2,096,929.48	840,722	1,049,668	1,047,261	44.93	23,309
1989	1,274,653.71	494,910	617,911	656,743	45.88	14,314
1990	824,587.30	309,608	386,555	438,032	46.84	9,352
1991	807,263.58	292,770	365,533	441,731	47.80	9,241
1992	1,905,490.89	666,407	832,030	1,073,461	48.77	22,011
1993	98,417.66	33,160	41,401	57,017	49.73	1,147
1994	896,204.82	290,254	362,391	533,814	50.71	10,527
1995	994,110.51	309,099	385,920	608,191	51.68	11,768
1996	711,873.74	212,046	264,746	447,128	52.66	8,491
1997	2,045.05	582	727	1,318	53.64	25
1998	63,080.50	17,141	21,401	41,680	54.62	763
1999	2,037.45	527	658	1,379	55.60	25
2000	38,888.73	9,546	11,918	26,971	56.59	477
2001	15,458.48	3,591	4,483	10,975	57.58	191
2002	375.82	82	102	274	58.57	5
2003	1.20			1	59.56	
2005	665,721.27	119,477	149,171	516,550	61.54	8,394
2006	1,499,244.71	249,279	311,233	1,188,012	62.53	18,999
2007	294,955.71	45,108	56,319	238,637	63.53	3,756
2008	2,082,786.68	291,028	363,358	1,719,429	64.52	26,650
2009	2,654,327.60	335,507	418,892	2,235,436	65.52	34,118
2010	54,333.44	6,143	7,670	46,663	66.52	701
2011	185,812.98	18,557	23,169	162,644	67.51	2,409
2013	1,630,605.28	119,360	149,025	1,481,580	69.51	21,315
2014	1,414,221.14	84,669	105,712	1,308,509	70.51	18,558
2015	3,929,738.14	183,401	228,982	3,700,756	71.50	51,759
2016	522,025.17	17,399	21,723	500,302	72.50	6,901
2017	1,636,880.77	32,738	40,875	1,596,006	73.50	21,714
	36,895,350.60	10,842,167	13,532,440	23,362,911		419,634

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 55.7 1.14

SURVIVOR CURVE.. IOWA 53-R1.5
NET SALVAGE PERCENT.. -20

1920	90.54	103	80	29	2.68	11
1922	163.58	184	144	52	3.29	16
1926	41,981.81	46,319	36,143	14,235	4.27	3,334
1928	62.48	68	53	22	4.72	5
1930	354,129.63	383,344	299,125	125,831	5.19	24,245
1931	32,287.81	34,783	27,141	11,604	5.42	2,141
1932	6,313.36	6,766	5,280	2,296	5.67	405
1935	5,708.33	6,019	4,697	2,153	6.43	335
1938	1,462.53	1,515	1,182	573	7.24	79
1940	34.47	35	27	14	7.81	2
1942	504.74	510	398	208	8.38	25
1945	82.87	82	64	35	9.28	4
1947	10,280.36	10,030	7,826	4,510	9.91	455
1948	416.39	403	314	186	10.22	18
1949	7,227.95	6,947	5,421	3,253	10.55	308
1950	94,265.99	89,898	70,148	42,971	10.88	3,950
1951	924.65	875	683	427	11.22	38
1952	9,628.72	9,034	7,049	4,505	11.56	390
1953	37,664.74	35,041	27,343	17,855	11.91	1,499
1954	6,763.33	6,237	4,867	3,249	12.27	265
1955	575,448.58	525,852	410,324	280,214	12.64	22,169
1956	2,683.91	2,430	1,896	1,325	13.01	102
1957	40,562.74	36,369	28,379	20,296	13.40	1,515
1958	22,838.27	20,275	15,821	11,585	13.79	840
1959	468,669.14	411,825	321,349	241,054	14.19	16,988
1960	34,986.32	30,418	23,735	18,249	14.60	1,250
1961	232,581.56	200,002	156,062	123,036	15.02	8,191
1962	382,339.40	325,060	253,646	205,161	15.45	13,279
1963	286,955.07	241,108	188,138	156,208	15.89	9,831
1964	264,300.25	219,380	171,183	145,977	16.34	8,934
1965	835,728.76	684,983	534,495	468,380	16.80	27,880
1966	1,174,117.56	949,838	741,162	667,779	17.27	38,667
1967	2,453,427.71	1,958,100	1,527,913	1,416,200	17.75	79,786
1968	682,911.07	537,465	419,386	400,107	18.24	21,936
1969	1,819,898.32	1,411,702	1,101,557	1,082,321	18.74	57,755
1970	2,418,403.56	1,848,018	1,442,016	1,460,068	19.25	75,848
1971	1,855,528.79	1,396,055	1,089,347	1,137,288	19.77	57,526
1972	991,546.66	734,117	572,834	617,022	20.30	30,395
1973	1,697,915.08	1,236,333	964,716	1,072,782	20.84	51,477
1974	2,795,444.07	2,001,314	1,561,633	1,792,900	21.38	83,859
1975	8,556,136.34	6,017,086	4,695,156	5,572,208	21.94	253,975
1976	1,992,787.66	1,375,693	1,073,459	1,317,886	22.51	58,547
1977	5,198,031.93	3,521,334	2,747,711	3,489,927	23.08	151,210

SURVIVOR CURVE.. IOWA 53-R1.5
NET SALVAGE PERCENT.. -20

1978	994,571.35	660,475	515,371	678,115	23.67	28,649
1979	4,889,257.30	3,181,498	2,482,536	3,384,573	24.26	139,512
1980	2,798,978.96	1,782,670	1,391,025	1,967,750	24.87	79,121
1981	10,083,067.97	6,282,760	4,902,463	7,197,219	25.48	282,465
1982	5,262,117.66	3,204,945	2,500,831	3,813,710	26.10	146,119
1983	742,248.27	441,653	344,624	546,074	26.72	20,437
1984	5,435,933.46	3,155,690	2,462,397	4,060,723	27.36	148,418
1985	3,403,493.65	1,926,514	1,503,267	2,580,925	28.00	92,176
1986	5,309,531.22	2,926,083	2,283,234	4,088,203	28.66	142,645
1987	9,666,031.74	5,182,424	4,043,866	7,555,372	29.32	257,687
1988	9,971,427.06	5,197,188	4,055,386	7,910,326	29.98	263,853
1989	9,749,460.07	4,931,394	3,847,986	7,851,366	30.66	256,078
1990	8,716,082.35	4,274,506	3,335,414	7,123,885	31.34	227,310
1991	8,838,245.98	4,198,344	3,275,985	7,329,910	32.02	228,917
1992	36,775,588.34	16,886,173	13,176,348	30,954,358	32.72	946,038
1993	7,773,424.87	3,446,084	2,688,993	6,639,117	33.42	198,657
1994	19,707,664.00	8,420,060	6,570,206	17,078,991	34.13	500,410
1995	12,208,190.73	5,019,617	3,916,827	10,733,002	34.84	308,065
1996	5,069,437.67	2,001,779	1,561,996	4,521,329	35.56	127,146
1997	908,660.66	343,986	268,414	821,979	36.28	22,657
1998	19,524,610.74	7,068,690	5,515,727	17,913,806	37.01	484,026
1999	1,629,328.94	562,588	438,990	1,516,205	37.75	40,164
2000	11,206,845.75	3,681,718	2,872,859	10,575,356	38.49	274,756
2001	20,322,666.29	6,336,038	4,944,036	19,443,164	39.23	495,620
2002	21,703,777.13	6,398,100	4,992,463	21,052,070	39.98	526,565
2003	2,228,166.93	619,012	483,018	2,190,782	40.73	53,788
2004	8,967,476.62	2,336,960	1,823,539	8,937,433	41.49	215,412
2005	34,013,366.09	8,270,962	6,453,865	34,362,174	42.26	813,113
2006	23,355,354.35	5,272,051	4,113,802	23,912,623	43.03	555,720
2007	18,529,627.32	3,859,647	3,011,698	19,223,855	43.80	438,901
2008	32,009,689.30	6,109,753	4,767,465	33,644,162	44.57	754,861
2009	26,301,950.45	4,549,711	3,550,158	28,012,183	45.36	617,553
2010	13,404,459.67	2,081,927	1,624,536	14,460,816	46.14	313,412
2011	27,042,329.09	3,716,590	2,900,070	29,550,725	46.93	629,677
2012	28,058,564.86	3,347,836	2,612,330	31,057,948	47.73	650,701
2013	11,500,950.02	1,163,988	908,264	12,892,876	48.53	265,668
2014	38,411,388.59	3,191,986	2,490,719	43,602,947	49.33	883,903
2015	39,877,281.68	2,582,134	2,014,849	45,837,889	50.14	914,198

SURVIVOR CURVE.. IOWA 53-R1.5
NET SALVAGE PERCENT.. -20

2016	98,187,922.77	4,557,491	3,556,228	114,269,279	50.95	2,242,773
2017	55,111,136.76	1,534,955	1,197,732	64,935,632	51.77	1,254,310
2018	47,289,935.11	439,229	342,732	56,405,190	52.59	1,072,546
	782,373,478.80	187,468,159	146,282,152	792,566,023		19,023,512

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.7 2.43

SURVIVOR CURVE.. IOWA 80-R4
NET SALVAGE PERCENT.. -10

1917	1,787.66	1,852	1,966			
1922	1,692.78	1,723	1,862			
1923	4,491.09	4,553	4,940			
1924	551.74	557	607			
1926	99,405.78	99,601	109,346			
1927	30,450.73	30,385	33,496			
1928	19,281.13	19,157	21,209			
1929	45,918.35	45,428	50,510			
1930	11,309.26	11,137	12,440			
1931	337,441.02	330,770	371,185			
1932	275,863.38	269,084	303,450			
1940	85,538.72	79,472	94,093			
1941	6,885.24	6,350	7,574			
1945	27,577.82	24,587	30,336			
1949	22,326.44	19,134	24,553	6	17.67	
1953	7,127.99	5,844	7,499	342	20.37	17
1954	71,825.72	58,199	74,681	4,327	21.07	205
1956	33,463.75	26,462	33,956	2,854	22.49	127
1957	396,154.69	309,345	396,953	38,817	23.21	1,672
1960	579,966.24	435,091	558,311	79,652	25.44	3,131
1961	2,321,257.15	1,717,150	2,203,457	349,926	26.20	13,356
1962	3,017,600.78	2,200,338	2,823,487	495,874	26.97	18,386
1963	1,518,196.62	1,090,721	1,399,620	270,396	27.75	9,744
1964	2,541,102.82	1,798,021	2,307,231	487,982	28.54	17,098
1965	2,040,742.23	1,421,530	1,824,116	420,700	29.34	14,339
1966	42,401.82	29,064	37,295	9,347	30.15	310
1967	2,204,678.55	1,486,324	1,907,260	517,886	30.97	16,722
1968	1,737,163.59	1,151,534	1,477,655	433,225	31.79	13,628
1969	2,526,591.41	1,645,650	2,111,708	667,543	32.63	20,458
1970	2,084,970.35	1,333,927	1,711,703	581,764	33.47	17,382
1971	984,517.60	618,376	793,504	289,465	34.32	8,434
1972	668,415.70	411,928	528,588	206,669	35.18	5,875
1973	292,270.87	176,625	226,646	94,852	36.05	2,631
1974	7,547.19	4,470	5,736	2,566	36.93	69
1975	92,392.21	53,598	68,777	32,854	37.81	869
1977	21,170.74	11,760	15,091	8,197	39.60	207
1978	182,497.26	99,093	127,157	73,590	40.51	1,817
1980	2,099,047.60	1,086,939	1,394,766	914,186	42.34	21,592
1981	280,519.66	141,712	181,846	126,726	43.26	2,929
1982	1,578,248.11	777,101	997,180	738,893	44.19	16,721
1983	16,477.88	7,903	10,141	7,985	45.12	177
1985	5,907,564.85	2,679,778	3,438,707	3,059,614	47.01	65,084
1988	2,689,436.15	1,114,185	1,429,729	1,528,651	49.87	30,653

SURVIVOR CURVE.. IOWA 80-R4
NET SALVAGE PERCENT.. -10

1992	30.47	11	14	20	53.73	
1993	58,554.43	20,370	26,139	38,271	54.70	700
1997	3,839.81	1,129	1,449	2,775	58.62	47
1998	2,506.66	703	902	1,855	59.61	31
2000	47,966.00	12,149	15,590	37,173	61.58	604
2001	601,788.03	144,229	185,075	476,892	62.57	7,622
2003	0.37					
2012	10,813.66	965	1,238	10,657	73.51	145
2013	115,204.05	8,696	11,159	115,565	74.51	1,551
	37,754,574.15	23,024,710	29,401,933	12,128,099		314,333

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.6 0.83

SURVIVOR CURVE.. IOWA 60-R2
NET SALVAGE PERCENT.. -20

1930	3,205.65	3,440	3,676	171	6.34	27
1938	37.21	38	41	4	8.73	
1939	2,739.79	2,792	2,983	305	9.04	34
1940	9,390.55	9,511	10,162	1,107	9.36	118
1941	7,150.71	7,195	7,688	893	9.69	92
1950	33,454.97	31,508	33,666	6,480	12.91	502
1951	46,390.15	43,319	46,285	9,383	13.31	705
1952	33,394.65	30,917	33,034	7,040	13.71	513
1953	544,179.93	499,231	533,417	119,599	14.13	8,464
1954	152,419.79	138,518	148,003	34,901	14.56	2,397
1955	225,931.60	203,385	217,312	53,806	14.99	3,589
1956	260,278.58	231,961	247,845	64,489	15.44	4,177
1957	770,590.99	679,661	726,203	198,506	15.90	12,485
1958	562,154.91	490,647	524,246	150,340	16.36	9,189
1959	596,520.21	514,914	550,174	165,650	16.84	9,837
1960	430,861.28	367,781	392,966	124,068	17.32	7,163
1961	355,339.00	299,764	320,291	106,116	17.82	5,955
1962	531,590.93	443,136	473,481	164,428	18.32	8,975
1963	604,760.85	497,839	531,930	193,783	18.84	10,286
1964	499,005.85	405,590	433,364	165,443	19.36	8,546
1965	851,325.24	682,759	729,513	292,077	19.90	14,677
1966	674,312.10	533,513	570,047	239,128	20.44	11,699
1967	710,541.62	554,222	592,174	260,476	21.00	12,404
1968	1,003,358.07	771,386	824,209	379,821	21.56	17,617
1969	1,098,257.76	831,601	888,547	429,362	22.14	19,393
1970	692,678.29	516,458	551,824	279,390	22.72	12,297
1971	815,600.90	598,488	639,471	339,250	23.31	14,554
1972	387,672.04	279,743	298,899	166,307	23.92	6,953
1973	651,491.27	462,171	493,820	287,970	24.53	11,740
1974	629,000.26	438,411	468,433	286,367	25.15	11,386
1975	667,562.35	456,877	488,163	312,912	25.78	12,138
1976	1,469,619.45	987,284	1,054,891	708,652	26.41	26,833
1977	795,925.42	524,356	560,263	394,848	27.06	14,592
1978	442,721.67	285,911	305,490	225,776	27.71	8,148
1979	1,276,938.35	807,536	862,834	669,492	28.38	23,590
1980	1,878,919.79	1,163,044	1,242,687	1,012,017	29.05	34,837
1981	10,257,852.56	6,210,104	6,635,360	5,674,063	29.73	190,853
1982	887,905.07	525,285	561,255	504,231	30.42	16,576
1983	1,571,970.46	908,285	970,483	915,882	31.11	29,440
1984	1,518,899.33	856,349	914,990	907,689	31.81	28,535
1985	1,197,607.18	658,205	703,278	733,851	32.52	22,566
1986	3,350,348.19	1,793,106	1,915,894	2,104,524	33.24	63,313
1987	5,035,998.67	2,621,721	2,801,251	3,241,947	33.97	95,436

SURVIVOR CURVE.. IOWA 60-R2
NET SALVAGE PERCENT.. -20

1988	3,909,039.26	1,977,990	2,113,439	2,577,408	34.70	74,277
1989	13,419,747.74	6,591,726	7,043,115	9,060,582	35.44	255,660
1990	8,754,373.73	4,168,798	4,454,269	6,050,979	36.19	167,200
1991	12,464,774.28	5,748,704	6,142,364	8,815,365	36.94	238,640
1992	4,474,779.56	1,995,770	2,132,436	3,237,299	37.70	85,870
1993	3,364,824.82	1,448,880	1,548,096	2,489,694	38.47	64,718
1994	965,561.63	400,704	428,143	730,531	39.25	18,612
1995	1,240,387.58	495,406	529,330	959,135	40.03	23,960
1996	1,434,262.13	550,464	588,159	1,132,956	40.81	27,762
1997	119,042.52	43,784	46,782	96,069	41.61	2,309
1998	9,438,813.98	3,320,613	3,548,002	7,778,575	42.41	183,414
2000	2,619,475.01	837,174	894,502	2,248,868	44.02	51,087
2001	4,681,774.71	1,419,533	1,516,740	4,101,390	44.84	91,467
2002	2,164,268.61	620,271	662,746	1,934,376	45.67	42,356
2003	542,157.48	146,493	156,525	494,064	46.49	10,627
2004	2,045,942.03	518,450	553,952	1,901,178	47.33	40,169
2005	2,241,777.24	530,413	566,735	2,123,398	48.17	44,081
2006	5,419,183.69	1,191,158	1,272,726	5,230,294	49.01	106,719
2007	5,324,568.99	1,078,736	1,152,606	5,236,877	49.87	105,011
2008	5,928,566.13	1,100,366	1,175,717	5,938,562	50.72	117,085
2009	4,188,027.47	705,247	753,541	4,272,092	51.58	82,825
2010	3,122,728.66	471,520	503,809	3,243,465	52.45	61,839
2011	2,519,645.24	336,615	359,666	2,663,908	53.32	49,961
2012	7,615,459.81	883,424	943,919	8,194,633	54.20	151,192
2013	4,210,297.87	414,293	442,663	4,609,694	55.08	83,691
2014	8,473,933.69	684,660	731,544	9,437,176	55.96	168,641
2015	7,856,452.92	494,957	528,851	8,898,893	56.85	156,533
2016	26,477,805.24	1,191,501	1,273,093	30,500,273	57.75	528,143
2017	116,297,551.82	3,163,759	3,380,407	136,176,655	58.64	2,322,249
2018	9,800,165.90	88,201	94,241	11,665,958	59.55	195,902
	324,651,293.38	70,987,572	75,848,661	313,732,891		6,344,631

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 49.4 1.95

SURVIVOR CURVE.. IOWA 65-R2
NET SALVAGE PERCENT.. -50

1910	5.71	8	7	2	3.24	1
1911	72.58	103	89	20	3.51	6
1913	440.90	620	539	122	4.08	30
1917	5.00	7	6	2	5.23	
1920	15,851.68	21,546	18,720	5,058	6.10	829
1921	306.32	414	360	99	6.40	15
1922	1,089.40	1,466	1,274	360	6.69	54
1923	1,576.41	2,111	1,834	531	6.98	76
1924	26,628.49	35,475	30,822	9,121	7.27	1,255
1925	27,119.49	35,948	31,233	9,446	7.56	1,249
1926	74,971.65	98,859	85,893	26,564	7.86	3,380
1927	25,961.30	34,053	29,587	9,355	8.16	1,146
1928	27,070.67	35,321	30,688	9,918	8.46	1,172
1929	27,401.57	35,563	30,899	10,203	8.76	1,165
1930	19,751.96	25,498	22,154	7,474	9.06	825
1931	119,928.36	153,961	133,768	46,125	9.37	4,923
1932	3,160.40	4,035	3,506	1,235	9.68	128
1933	143.63	182	158	57	10.00	6
1934	458.02	578	502	185	10.32	18
1935	10,044.54	12,601	10,948	4,119	10.64	387
1936	11,048.63	13,776	11,969	4,604	10.97	420
1937	742.04	919	798	315	11.31	28
1938	120.43	148	129	52	11.66	4
1939	21,502.97	26,295	22,846	9,408	12.01	783
1940	108,219.24	131,462	114,220	48,109	12.36	3,892
1941	56,882.42	68,613	59,614	25,710	12.73	2,020
1942	10,390.19	12,444	10,812	4,773	13.10	364
1943	10,941.62	13,009	11,303	5,109	13.48	379
1944	11,205.38	13,222	11,488	5,320	13.87	384
1945	48,025.96	56,235	48,859	23,180	14.26	1,626
1946	16,923.95	19,657	17,079	8,307	14.67	566
1947	4,563.33	5,257	4,567	2,278	15.08	151
1948	60,712.44	69,352	60,256	30,813	15.50	1,988
1949	61,813.49	69,996	60,815	31,905	15.93	2,003
1950	156,398.19	175,514	152,494	82,103	16.37	5,015
1951	395,442.34	439,671	382,004	211,160	16.82	12,554
1952	103,400.93	113,868	98,933	56,168	17.28	3,250
1953	888,474.41	968,988	841,896	490,816	17.74	27,667
1954	281,289.08	303,661	263,833	158,101	18.22	8,677
1955	356,250.42	380,556	330,643	203,733	18.71	10,889
1956	415,579.99	439,239	381,629	241,741	19.20	12,591
1957	1,199,662.78	1,254,103	1,089,616	709,878	19.70	36,034
1958	744,723.89	769,762	668,801	448,285	20.21	22,181

SURVIVOR CURVE.. IOWA 65-R2
NET SALVAGE PERCENT.. -50

1959	670,311.48	684,643	594,846	410,621	20.74	19,799
1960	612,512.85	618,120	537,048	381,721	21.27	17,946
1961	1,203,741.02	1,199,757	1,042,398	763,214	21.81	34,994
1962	1,478,444.66	1,455,122	1,264,269	953,398	22.35	42,658
1963	892,146.89	866,551	752,895	585,325	22.91	25,549
1964	2,538,225.12	2,432,013	2,113,032	1,694,306	23.48	72,160
1965	2,345,088.78	2,216,109	1,925,446	1,592,187	24.05	66,203
1966	1,242,363.02	1,157,112	1,005,346	858,199	24.64	34,830
1967	3,127,141.49	2,870,012	2,493,583	2,197,129	25.23	87,084
1968	2,307,124.28	2,085,479	1,811,949	1,648,737	25.83	63,830
1969	1,872,671.03	1,666,387	1,447,825	1,361,182	26.44	51,482
1970	1,595,930.20	1,397,293	1,214,025	1,179,870	27.06	43,602
1971	1,206,378.72	1,038,692	902,458	907,110	27.69	32,759
1972	1,810,634.63	1,532,639	1,331,619	1,384,333	28.32	48,882
1973	1,415,806.84	1,177,512	1,023,070	1,100,640	28.96	38,006
1974	862,327.90	704,255	611,885	681,607	29.61	23,019
1975	885,191.25	709,450	616,399	711,388	30.27	23,501
1976	3,138,697.13	2,467,016	2,143,444	2,564,602	30.94	82,890
1977	1,587,987.04	1,223,600	1,063,113	1,318,868	31.61	41,723
1978	1,244,030.88	939,050	815,885	1,050,161	32.29	32,523
1979	1,719,917.17	1,270,898	1,104,208	1,475,668	32.98	44,744
1980	1,373,332.51	992,919	862,688	1,197,311	33.67	35,560
1981	7,474,680.16	5,281,758	4,589,006	6,623,014	34.38	192,641
1982	2,123,727.80	1,465,850	1,273,590	1,912,002	35.09	54,489
1983	1,658,303.97	1,117,440	970,877	1,516,579	35.80	42,363
1984	1,375,201.63	903,507	785,004	1,277,798	36.53	34,979
1985	4,187,515.30	2,680,659	2,329,066	3,952,207	37.26	106,071
1986	4,018,100.50	2,504,522	2,176,031	3,851,120	37.99	101,372
1987	4,173,921.73	2,529,397	2,197,643	4,063,240	38.74	104,885
1988	10,051,671.07	5,917,318	5,141,207	9,936,300	39.49	251,616
1989	7,789,209.59	4,450,599	3,866,861	7,816,953	40.24	194,258
1990	6,278,231.71	3,475,755	3,019,877	6,397,471	41.01	155,998
1991	18,327,424.61	9,824,783	8,536,171	18,954,966	41.77	453,794
1992	5,111,069.00	2,647,892	2,300,596	5,366,008	42.55	126,111
1993	3,040,811.41	1,520,619	1,321,176	3,240,041	43.33	74,776
1994	1,781,238.30	858,281	745,709	1,926,148	44.12	43,657
1995	947,733.98	439,388	381,758	1,039,843	44.91	23,154
1996	2,246,677.24	1,000,120	868,945	2,501,071	45.71	54,716
1997	109,589.32	46,761	40,628	123,756	46.51	2,661
1998	14,918,676.24	6,086,820	5,288,477	17,089,537	47.32	361,148
1999	554.76	216	188	644	48.14	13
2000	3,695,982.93	1,368,087	1,188,650	4,355,324	48.96	88,957
2001	4,340,394.27	1,524,455	1,324,508	5,186,083	49.78	104,180

SURVIVOR CURVE.. IOWA 65-R2
NET SALVAGE PERCENT.. -50

2002	4,635,208.24	1,539,214	1,337,332	5,615,480	50.61	110,956
2003	558,173.94	174,535	151,643	685,618	51.45	13,326
2004	802,240.49	235,305	204,443	998,918	52.29	19,103
2005	1,795,056.18	491,720	427,226	2,265,358	53.13	42,638
2006	4,579,479.91	1,163,508	1,010,903	5,858,317	53.99	108,507
2007	8,575,725.94	2,010,708	1,746,985	11,116,604	54.84	202,710
2008	20,179,276.01	4,330,876	3,762,841	26,506,073	55.70	475,872
2009	5,973,053.76	1,161,968	1,009,565	7,950,016	56.57	140,534
2010	3,334,639.36	581,778	505,472	4,496,487	57.44	78,281
2011	4,055,078.77	626,023	543,914	5,538,704	58.31	94,987
2012	24,827,073.41	3,328,566	2,891,994	34,348,616	59.19	580,311
2013	10,540,901.74	1,199,291	1,041,993	14,769,360	60.07	245,869
2014	13,653,104.79	1,272,811	1,105,870	19,373,787	60.96	317,811
2015	4,244,668.57	308,545	268,076	6,098,927	61.85	98,608
2016	14,023,452.77	728,238	632,723	20,402,456	62.75	325,139
2017	23,141,095.92	726,168	630,924	34,080,720	63.64	535,524
2018	5,465,847.47	56,735	49,294	8,149,477	64.55	126,251
	294,511,099.88	112,128,941	97,422,188	344,344,462		7,222,141

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.7 2.45

SURVIVOR CURVE.. IOWA 65-R2
NET SALVAGE PERCENT.. 0

1923	1,041.79	930	1,042
1924	5,968.47	5,301	5,968
1925	7,632.52	6,745	7,633
1926	6,195.56	5,446	6,196
1927	429.80	376	430
1928	16,182.50	14,076	16,182
1929	7,440.64	6,438	7,441
1930	1,256.05	1,081	1,256
1931	62,495.62	53,487	62,496
1932	454.18	387	454
1933	51.32	43	51
1936	37.21	31	37
1937	89.81	74	90
1938	125,174.34	102,721	125,174
1939	2,249.89	1,834	2,250
1940	1,018.18	825	1,018
1941	11,049.21	8,885	11,049
1942	429.54	343	430
1943	881.14	698	881
1944	91.80	72	92
1945	14,651.53	11,437	14,652
1946	15,357.32	11,891	15,357
1947	7,259.80	5,576	7,260
1948	19,245.91	14,657	19,246
1949	102,472.21	77,358	102,472
1950	43,923.08	32,861	43,923
1951	84,923.43	62,948	84,923
1952	15,080.83	11,072	15,081
1953	343,136.20	249,487	343,136
1954	83,619.74	60,180	83,620
1955	149,124.16	106,199	149,124
1956	315,907.04	222,594	315,907
1957	151,623.98	105,670	151,624
1958	362,269.63	249,633	362,270
1959	164,646.02	112,111	164,646
1960	114,638.01	77,125	114,638
1961	376,747.30	250,334	376,747
1962	619,930.48	406,767	619,930
1963	348,096.15	225,406	348,096
1964	412,163.98	263,278	412,164
1965	436,372.61	274,915	436,373
1966	516,505.29	320,708	516,505
1967	405,420.34	248,056	405,420

SURVIVOR CURVE.. IOWA 65-R2
NET SALVAGE PERCENT.. 0

1968	301,185.44	181,500	301,185			
1969	285,487.80	169,360	283,571	1,917	26.44	73
1970	172,561.11	100,722	168,646	3,915	27.06	145
1971	259,891.91	149,178	249,779	10,113	27.69	365
1972	107,360.26	60,584	101,440	5,920	28.32	209
1973	110,046.45	61,016	102,163	7,883	28.96	272
1974	36,930.54	20,107	33,667	3,264	29.61	110
1975	50,625.13	27,050	45,292	5,333	30.27	176
1976	88,541.86	46,396	77,684	10,858	30.94	351
1977	122,293.52	62,821	105,186	17,108	31.61	541
1978	60,317.25	30,353	50,822	9,495	32.29	294
1979	56,537.10	27,851	46,633	9,904	32.98	300
1980	7,831.95	3,775	6,321	1,511	33.67	45
1981	412,792.04	194,458	325,594	87,198	34.38	2,536
1982	547,347.58	251,862	421,710	125,638	35.09	3,580
1983	90,626.00	40,712	68,167	22,459	35.80	627
1984	213,141.93	93,356	156,312	56,830	36.53	1,556
1985	166,688.44	71,138	119,111	47,577	37.26	1,277
1986	178,690.04	74,253	124,327	54,363	37.99	1,431
1987	40,436.75	16,336	27,352	13,085	38.74	338
1988	505,462.95	198,374	332,151	173,312	39.49	4,389
1989	1,023,773.93	389,976	652,964	370,810	40.24	9,215
1990	271,033.36	100,033	167,492	103,541	41.01	2,525
1991	298,477.64	106,670	178,605	119,873	41.77	2,870
1992	287,710.70	99,370	166,382	121,329	42.55	2,851
1993	11,293.10	3,765	6,304	4,989	43.33	115
1994	64,407.54	20,690	34,643	29,765	44.12	675
1995	6,358.82	1,965	3,290	3,069	44.91	68
1996	153,881.68	45,667	76,463	77,419	45.71	1,694
1998	129,680.15	35,273	59,060	70,620	47.32	1,492
2000	373,667.00	92,210	154,394	219,273	48.96	4,479
2001	402,909.77	94,341	157,962	244,948	49.78	4,921
2002	407,830.00	90,285	151,170	256,660	50.61	5,071
2003	40,812.32	8,508	14,246	26,566	51.45	516
2004	14,409.95	2,818	4,718	9,692	52.29	185
2007	537,367.04	83,996	140,640	396,727	54.84	7,234
2008	1,337,971.37	191,437	320,536	1,017,435	55.70	18,266
2009	2,464,079.87	319,567	535,074	1,929,006	56.57	34,099
2010	1,292,212.10	150,297	251,653	1,040,559	57.44	18,116
2011	1,334,201.57	137,316	229,918	1,104,284	58.31	18,938
2012	221,191.70	19,770	33,102	188,090	59.19	3,178
2013	1,318,425.91	100,003	167,442	1,150,984	60.07	19,161
2014	2,446,776.54	152,067	254,616	2,192,161	60.96	35,961

SURVIVOR CURVE.. IOWA 65-R2
NET SALVAGE PERCENT.. 0

2015	1,083,040.33	52,484	87,878	995,162	61.85	16,090
2016	587,991.40	20,356	34,083	553,908	62.75	8,827
2017	2,749,279.32	57,515	96,302	2,652,977	63.64	41,687
2018	6,336,673.79	43,850	73,421	6,263,253	64.55	97,029
	34,363,537.56	7,911,487	12,552,755	21,810,783		373,878

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 58.3   1.09

SURVIVOR CURVE.. IOWA 60-R2
NET SALVAGE PERCENT.. 0

1928	56,067.82	50,685	56,068			
1956	32,218.50	23,928	27,846	4,372	15.44	283
1957	19,334.99	14,211	16,538	2,797	15.90	176
1958	211.68	154	179	33	16.36	2
1959	1,985.36	1,428	1,662	323	16.84	19
1960	12,221.68	8,694	10,118	2,104	17.32	121
1961	222.74	157	183	40	17.82	2
1962	7,026.34	4,881	5,680	1,346	18.32	73
1964	19,414.75	13,150	15,303	4,112	19.36	212
1966	11,886.68	7,837	9,120	2,767	20.44	135
1968	10,497.30	6,725	7,826	2,671	21.56	124
1969	13,145.20	8,295	9,653	3,492	22.14	158
1970	2,441.61	1,517	1,765	677	22.72	30
1971	13,699.96	8,378	9,750	3,950	23.31	169
1973	4,929.47	2,914	3,391	1,538	24.53	63
1974	53,437.50	31,038	36,120	17,318	25.15	689
1975	11,575.03	6,602	7,683	3,892	25.78	151
1976	97,270.98	54,455	63,371	33,900	26.41	1,284
1977	6,830.86	3,750	4,364	2,467	27.06	91
1978	7,300.20	3,929	4,572	2,728	27.71	98
1979	17,728.22	9,343	10,873	6,855	28.38	242
1980	247,523.43	127,680	148,586	98,937	29.05	3,406
1981	80,449.67	40,587	47,232	33,218	29.73	1,117
1985	39,165.50	17,938	20,875	18,290	32.52	562
1986	105,851.69	47,210	54,940	50,912	33.24	1,532
1987	18,000.49	7,809	9,088	8,912	33.97	262
1988	150,308.12	63,380	73,758	76,550	34.70	2,206
1989	47,011.37	19,243	22,394	24,617	35.44	695
1990	83,995.68	33,332	38,790	45,206	36.19	1,249
1991	44,271.02	17,015	19,801	24,470	36.94	662
1992	117,829.97	43,794	50,964	66,866	37.70	1,774
1993	47,685.78	17,111	19,913	27,773	38.47	722
1994	16,209.22	5,606	6,524	9,685	39.25	247
1996	364,784.89	116,669	135,771	229,014	40.81	5,612
1997	1,342.34	411	478	864	41.61	21
1998	5,207.89	1,527	1,777	3,431	42.41	81
2000	897.00	239	278	619	44.02	14
2009	62,384.21	8,754	10,187	52,197	51.58	1,012

SURVIVOR CURVE.. IOWA 60-R2
NET SALVAGE PERCENT.. 0

2012	30,395.70	2,938	3,420	26,976	54.20	498
2014	1,704.88	115	133	1,572	55.96	28
2015	527.66	28	33	495	56.85	9
	1,864,993.38	833,457	967,007	897,986		25,831

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.8 1.39

SURVIVOR CURVE.. IOWA 55-R3
NET SALVAGE PERCENT.. -15

1928	27,806.19	31,628	31,977			
1936	7,513.32	8,243	8,640			
1950	75,354.20	76,936	86,657			
1951	3,398.42	3,449	3,908			
1952	928.73	937	1,068			
1955	44,882.03	44,388	51,614			
1956	847.01	832	968	6	8.04	1
1957	107,253.15	104,503	121,548	1,793	8.40	213
1959	6,550.13	6,278	7,302	231	9.16	25
1960	36,568.37	34,744	40,411	1,643	9.56	172
1962	9,113.50	8,497	9,883	598	10.41	57
1963	9,013.24	8,319	9,676	689	10.86	63
1964	73,739.20	67,331	78,313	6,487	11.33	573
1966	13,029.18	11,625	13,521	1,463	12.33	119
1967	17,780.02	15,670	18,226	2,221	12.85	173
1968	345,845.78	300,897	349,974	47,749	13.39	3,566
1969	279,852.73	240,263	279,451	42,380	13.94	3,040
1970	52,449.76	44,404	51,646	8,671	14.51	598
1971	140,785.65	117,453	136,610	25,293	15.10	1,675
1972	2,837.25	2,331	2,711	552	15.71	35
1973	48,328.92	39,087	45,462	10,116	16.32	620
1974	62,423.89	49,651	57,749	14,038	16.96	828
1975	89,511.59	69,980	81,394	21,544	17.61	1,223
1976	535,032.15	410,901	477,920	137,367	18.27	7,519
1977	74,442.58	56,129	65,284	20,325	18.94	1,073
1978	34,152.35	25,257	29,376	9,899	19.63	504
1979	163,056.88	118,202	137,481	50,034	20.33	2,461
1980	185,934.46	132,026	153,560	60,265	21.04	2,864
1981	647,884.82	450,155	523,577	221,491	21.77	10,174
1982	4,740.21	3,221	3,746	1,705	22.50	76
1983	2,405.07	1,597	1,857	909	23.25	39
1984	3,711.04	2,405	2,797	1,471	24.01	61
1985	41,808.80	26,427	30,737	17,343	24.77	700
1986	115,528.09	71,138	82,741	50,116	25.55	1,961
1987	37,593.38	22,528	26,202	17,030	26.34	647
1988	170,126.18	99,104	115,268	80,377	27.14	2,962
1989	73,868.33	41,795	48,612	36,337	27.94	1,301
1990	296,690.48	162,780	189,330	151,864	28.76	5,280
1991	234,810.05	124,755	145,103	124,929	29.59	4,222
1992	385,103.77	197,923	230,205	212,664	30.42	6,991
1993	106,856.53	53,042	61,693	61,192	31.26	1,958
1994	311,979.61	149,316	173,670	185,107	32.11	5,765
1995	4,887.59	2,251	2,618	3,003	32.97	91

SURVIVOR CURVE.. IOWA 55-R3
NET SALVAGE PERCENT.. -15

1996	218,520.14	96,682	112,451	138,847	33.84	4,103
1997	53,306.17	22,604	26,291	35,011	34.72	1,008
1998	60,021.95	24,347	28,318	40,707	35.60	1,143
2000	88,714.00	32,665	37,993	64,028	37.39	1,712
2001	80,311.44	28,044	32,618	59,740	38.30	1,560
2002	356,504.00	117,701	136,898	273,082	39.21	6,965
2003	12,802.00	3,980	4,629	10,093	40.13	252
2004	6,125,597.68	1,785,413	2,076,619	4,967,818	41.06	120,989
2005	659,189.46	179,321	208,569	549,499	41.99	13,086
2006	108,119.42	27,286	31,736	92,601	42.93	2,157
2007	349,685.09	81,377	94,650	307,488	43.87	7,009
2008	175,410.65	37,373	43,469	158,253	44.81	3,532
2009	514,162.99	99,230	115,415	475,872	45.77	10,397
2010	88,921.23	15,395	17,906	84,353	46.72	1,806
2011	220,871.33	33,759	39,265	214,737	47.69	4,503
2012	2,128,549.64	282,602	328,695	2,119,137	48.65	43,559
2013	258,232.89	29,049	33,787	263,181	49.62	5,304
2014	735,321.64	67,802	78,861	766,759	50.59	15,156
2015	1,061,628.73	76,134	88,552	1,132,321	51.57	21,957
2016	1,589,643.35	81,770	95,107	1,732,983	52.54	32,984
2017	1,197,316.33	37,053	43,096	1,333,818	53.52	24,922
2018	331,382.71	3,396	3,950	377,140	54.51	6,919
	21,300,637.47	6,601,381	7,669,361	16,826,372		400,653

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.0   1.88

SURVIVOR CURVE.. IOWA 70-R4
NET SALVAGE PERCENT.. 0

1963	57.63	42	58			
1967	2,685.98	1,841	2,521	165	22.03	7
1974	11,533.65	6,993	9,575	1,959	27.56	71
1981	3,082.11	1,603	2,195	887	33.59	26
1988	254,830.40	109,177	149,486	105,344	40.01	2,633
1989	1,656,456.65	687,430	941,232	715,225	40.95	17,466
1990	8,725.57	3,503	4,796	3,930	41.90	94
1991	52,386.58	20,311	27,810	24,577	42.86	573
1992	44,517.73	16,656	22,805	21,713	43.81	496
2003	0.26					
2015	358,545.69	17,927	24,546	334,000	66.50	5,023
	2,392,822.25	865,483	1,185,024	1,207,798		26,389

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.8   1.10

SURVIVOR CURVE.. IOWA 50-R3
NET SALVAGE PERCENT.. 0

1962	33.90	29	17	17	7.42	2
1975	7.69	6	3	5	13.54	
1978	1,105.95	766	438	668	15.39	43
2008	0.41					
	1,147.95	801	458	690		45

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.3 3.92

SURVIVOR CURVE.. IOWA 50-R1.5
NET SALVAGE PERCENT.. -5

1890	1,209.45	1,270	1,270			
1896	1,834.48	1,926	1,926			
1902	2,041.67	2,144	2,144			
1910	343.40	361	361			
1911	3,794.38	3,984	3,984			
1922	361.69	370	380			
1923	79.37	81	83			
1924	161.91	163	170			
1925	5,401.31	5,406	5,671			
1926	2,767.55	2,751	2,906			
1927	561.36	554	589			
1928	11,402.86	11,192	11,973			
1929	721.84	705	758			
1930	13,150.27	12,772	13,808			
1931	733.26	709	770			
1932	119.09	115	125			
1935	134.69	128	141			
1938	752.77	702	790			
1939	354.73	329	372			
1940	188.53	174	198			
1947	645.86	568	678			
1950	6.30	5	7			
1951	420.38	359	441			
1953	1,444.18	1,214	1,516			
1954	3,011.88	2,511	3,162			
1955	283.75	235	298			
1956	26,760.15	21,922	28,098			
1957	16,372.87	13,292	17,192			
1958	30,669.31	24,667	32,203			
1959	40,840.00	32,530	42,882			
1960	26,601.37	20,977	27,931			
1961	5,026.94	3,923	5,278			
1962	18,524.09	14,300	19,450			
1963	5,220.45	3,985	5,481			
1964	38,646.06	29,160	40,578			
1965	17,630.21	13,147	18,512			
1966	64,376.81	47,412	67,596			
1967	43,129.80	31,356	45,286			
1968	3,094.14	2,220	3,249			
1969	23,651.49	16,733	24,749	85	16.31	5
1970	44,049.34	30,720	45,436	816	16.79	49
1971	2,604.61	1,790	2,647	88	17.28	5
1972	4,306.86	2,914	4,310	212	17.78	12

SURVIVOR CURVE.. IOWA 50-R1.5
NET SALVAGE PERCENT.. -5

1973	12,421.51	8,272	12,235	808	18.29	44
1974	3,555.17	2,329	3,445	288	18.81	15
1975	1,733.20	1,116	1,651	169	19.35	9
1976	7,198.11	4,551	6,731	827	19.89	42
1977	6,080.74	3,775	5,583	802	20.44	39
1978	51,297.18	31,240	46,205	7,657	21.00	365
1979	140,694.86	83,970	124,196	23,534	21.58	1,091
1980	5,887.76	3,442	5,091	1,091	22.16	49
1981	95,472.36	54,634	80,806	19,440	22.75	855
1982	54,592.12	30,552	45,188	12,134	23.35	520
1983	45,044.87	24,632	36,432	10,865	23.96	453
1984	111,014.21	59,262	87,651	28,914	24.58	1,176
1985	463,757.13	241,427	357,082	129,863	25.21	5,151
1986	223,921.74	113,609	168,033	67,085	25.84	2,596
1987	424,599.55	209,629	310,051	135,779	26.49	5,126
1988	209,894.38	100,762	149,032	71,357	27.14	2,629
1989	129,558.83	60,400	89,334	46,703	27.80	1,680
1990	1,005,891.59	454,794	672,661	383,525	28.47	13,471
1991	314,866.70	137,931	204,006	126,604	29.14	4,345
1992	409,730.88	173,550	256,689	173,528	29.83	5,817
1993	227,048.68	92,881	137,375	101,026	30.52	3,310
1994	86,529.38	34,125	50,472	40,384	31.22	1,294
1995	178,892.46	67,922	100,460	87,377	31.92	2,737
1996	90,428.32	32,986	48,788	46,162	32.63	1,415
1997	132,358.80	46,279	68,449	70,528	33.35	2,115
1998	650,396.74	217,577	321,807	361,110	34.07	10,599
1999	103,846.34	33,148	49,027	60,012	34.80	1,724
2000	231,035.40	70,205	103,836	138,751	35.53	3,905
2001	248,866.15	71,756	106,131	155,178	36.27	4,278
2002	60,774.49	16,566	24,502	39,311	37.02	1,062
2003	143,789.25	36,929	54,620	96,359	37.77	2,551
2004	16,445.69	3,965	5,864	11,404	38.52	296
2005	53,498.52	12,044	17,814	38,359	39.28	977
2006	49,710.47	10,387	15,363	36,833	40.05	920
2007	60,956.10	11,751	17,380	46,624	40.82	1,142
2008	115,781.08	20,448	30,244	91,326	41.59	2,196
2009	106,792.10	17,111	25,308	86,824	42.37	2,049
2010	55,696.13	8,012	11,850	46,631	43.15	1,081
2011	28,764.20	3,661	5,415	24,787	43.94	564
2012	32,149.17	3,558	5,262	28,495	44.73	637
2013	44,144.15	4,144	6,129	40,222	45.53	883
2014	44,262.23	3,411	5,045	41,430	46.33	894
2015	213,559.52	12,826	18,970	205,267	47.14	4,354

SURVIVOR CURVE.. IOWA 50-R1.5
NET SALVAGE PERCENT.. -5

2016	342,517.09	14,745	21,809	337,834	47.95	7,046
2017	1,669,266.32	43,117	63,772	1,688,958	48.77	34,631
2018	100,881.95	869	1,285	104,641	49.59	2,110
	9,269,035.08	3,052,076	4,464,478	5,268,009		140,314

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.5 1.51

SURVIVOR CURVE.. IOWA 60-R3
NET SALVAGE PERCENT.. 0

1910	84.32	84	84
1911	57.30	57	57
1918	130.38	130	130
1919	39.23	39	39
1922	32.00	31	32
1923	215.39	210	215
1924	123.77	120	124
1925	462.26	448	462
1926	85.80	83	86
1927	205.89	198	206
1928	3,688.78	3,527	3,689
1929	799.51	761	800
1930	91.48	87	91
1932	57.88	54	58
1935	2.78	3	3
1938	282.87	258	283
1939	24.92	23	25
1940	9.64	9	10
1941	139.32	125	139
1943	23.58	21	24
1945	81.38	72	81
1947	58.31	51	58
1948	6.62	6	7
1950	14.78	13	15
1951	634.24	539	634
1952	43.76	37	44
1953	2,098.88	1,757	2,099
1954	3,209.06	2,666	3,209
1955	1,616.67	1,332	1,617
1956	5,601.07	4,576	5,601
1957	1,824.26	1,477	1,824
1958	3,078.51	2,469	3,079
1959	12,170.63	9,667	12,171
1960	4,772.66	3,752	4,773
1961	5,197.00	4,042	5,197
1962	14,601.58	11,231	14,602
1963	3,477.22	2,644	3,477
1964	12,267.89	9,215	12,268
1965	9,621.86	7,138	9,622
1966	28,799.87	21,086	28,800
1967	12,054.23	8,707	12,054
1968	6,086.19	4,334	6,086
1969	6,668.00	4,680	6,668

SURVIVOR CURVE.. IOWA 60-R3
NET SALVAGE PERCENT.. 0

1970	12,007.44	8,299	12,007			
1971	2,204.21	1,500	2,204			
1972	4,051.13	2,712	4,051			
1973	4,184.05	2,754	4,184			
1974	9,825.26	6,355	9,825			
1975	975.49	620	975			
1976	1,259.83	785	1,260			
1977	4,461.10	2,727	4,461			
1978	12,687.35	7,602	12,687			
1979	15,231.62	8,938	15,232			
1980	6,617.32	3,802	6,617			
1981	22,018.88	12,371	22,019			
1982	28,281.86	15,527	28,282			
1983	103,529.98	55,492	103,530			
1984	30,088.51	15,731	29,392	697	28.63	24
1985	19,978.88	10,183	19,026	953	29.42	32
1986	50,753.78	25,183	47,052	3,702	30.23	122
1987	20,723.22	10,002	18,688	2,035	31.04	66
1988	72,487.94	33,997	63,520	8,968	31.86	281
1989	44,848.49	20,414	38,141	6,707	32.69	205
1990	85,547.96	37,741	70,515	15,033	33.53	448
1991	97,965.29	41,831	78,157	19,808	34.38	576
1992	22,191.92	9,161	17,116	5,076	35.23	144
1993	26,088.61	10,396	19,424	6,665	36.09	185
1994	31,256.83	12,003	22,427	8,830	36.96	239
1995	32,231.44	11,904	22,241	9,990	37.84	264
1996	8,263.83	2,931	5,476	2,788	38.72	72
1997	39,767.10	13,514	25,250	14,517	39.61	366
1998	37,495.65	12,180	22,757	14,739	40.51	364
1999	14,220.05	4,406	8,232	5,988	41.41	145
2000	27,886.43	8,217	15,353	12,533	42.32	296
2001	3,548.53	991	1,852	1,697	43.24	39
2002	12,006.88	3,170	5,923	6,084	44.16	138
2003	6,066.35	1,509	2,819	3,247	45.08	72
2006	4,383.81	884	1,652	2,732	47.90	57
2007	4,449.71	827	1,545	2,905	48.85	59
2008	56,031.82	9,525	17,797	38,235	49.80	768

SURVIVOR CURVE.. IOWA 60-R3
NET SALVAGE PERCENT.. 0

2009	5,097.97	786	1,468	3,630	50.75	72
2010	6,045.10	835	1,560	4,485	51.71	87
2011	6,990.21	853	1,594	5,396	52.68	102
	1,134,293.60	536,417	926,854	207,440		5,223

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.7 0.46

FULLY ACCRUED
NET SALVAGE PERCENT.. 0

1993	114,088.81	114,089	114,089			
	114,088.81	114,089	114,089			

AMORTIZED
SURVIVOR CURVE.. 25-SQUARE
NET SALVAGE PERCENT.. 0

1994	43,190.53	42,327	42,122	1,068	0.50	1,068
1995	55,622.69	52,285	52,032	3,591	1.50	2,394
1996	45,880.21	41,292	41,092	4,788	2.50	1,915
1997	35,748.64	30,744	30,595	5,153	3.50	1,472
1998	345,079.61	282,965	281,596	63,484	4.50	14,108
1999	33,432.98	26,078	25,952	7,481	5.50	1,360
2000	56,416.10	41,748	41,546	14,870	6.50	2,288
2001	23,255.50	16,279	16,200	7,055	7.50	941
2002	209.43	138	137	72	8.50	8
2003	179.68	111	110	69	9.50	7
2004	4,523.71	2,624	2,611	1,912	10.50	182
2007	10,247.96	4,714	4,691	5,557	13.50	412
2008	9,853.50	4,138	4,118	5,736	14.50	396
2009	14,238.73	5,411	5,385	8,854	15.50	571
2011	401.91	121	120	281	17.50	16
2013	1,728.48	380	378	1,350	19.50	69
2014	1,067.28	192	191	876	20.50	43
2015	163.93	23	23	141	21.50	7
2016	432.10	43	43	389	22.50	17
2017	103,421.29	6,205	6,175	97,246	23.50	4,138
2018	15,393.73	308	307	15,087	24.50	616
	800,487.99	558,126	555,425	245,063		32,028

	914,576.80	672,215	669,514	245,063		32,028

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.7   3.50

SURVIVOR CURVE.. 20-SQUARE
NET SALVAGE PERCENT.. 0

1998	222,980.22	222,980	222,980
	222,980.22	222,980	222,980

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

FULLY ACCRUED
NET SALVAGE PERCENT.. 0

2011	581.51	582	582			
2013	239,178.66	239,179	239,178			
	239,760.17	239,761	239,760			

AMORTIZED
SURVIVOR CURVE.. 5-SQUARE
NET SALVAGE PERCENT.. 0

2014	206,614.71	185,953	171,912	34,703	0.50	34,703
2015	135,140.00	94,598	87,455	47,685	1.50	31,790
2016	66,100.77	33,050	30,554	35,546	2.50	14,218
2017	108,662.60	32,599	30,137	78,525	3.50	22,436
2018	110,461.30	11,046	10,212	100,249	4.50	22,278
	626,979.38	357,246	330,270	296,709		125,425
	866,739.55	597,007	570,030	296,709		125,425

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.4   14.47

SURVIVOR CURVE.. 5-SQUARE
NET SALVAGE PERCENT.. 0

2012	1,396.84	1,397	1,397
	1,396.84	1,397	1,397

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

SURVIVOR CURVE.. IOWA 13-L2
NET SALVAGE PERCENT.. +5

1969	2,203.82	2,094	2,094			
1971	296.01	281	281			
1976	3,050.22	2,898	2,898			
1977	374.13	355	355			
1978	1,148.03	1,091	1,091			
1979	1,721.84	1,636	1,636			
1983	217.09	201	206			
1985	4,163.77	3,764	3,956			
1987	6,788.16	5,963	6,449			
1988	21,616.26	18,703	20,535			
1989	107.87	92	102			
1990	477.89	401	454			
1991	17,481.96	14,410	16,608			
1992	2,563.55	2,076	2,435			
1993	5,631.17	4,477	5,350			
1994	7,799.75	6,087	7,410			
1995	2,095.58	1,603	1,991			
1998	81,907.77	58,599	77,812			
1999	23,886.61	16,670	22,692			
2000	17,199.89	11,689	16,340			
2001	447.00	296	425			
2003	0.02					
2007	1,289.10	713	1,031	194	5.43	36
2009	45,123.57	23,049	33,331	9,536	6.01	1,587
2010	404.04	195	282	102	6.38	16
2011	772.98	348	503	231	6.84	34
2013	57,333.21	20,613	29,809	24,658	8.08	3,052
2015	2,200.42	532	769	1,321	9.69	136
2016	175.27	31	45	122	10.58	12
2017	104,681.03	11,322	16,373	83,074	11.52	7,211
2018	113,887.92	4,161	6,017	102,177	12.50	8,174
	527,045.93	214,350	279,280	221,414		20,258

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.9 3.84

FULLY ACCRUED
NET SALVAGE PERCENT.. 0

1988	2,678.46	2,678	2,678			
	2,678.46	2,678	2,678			

AMORTIZED
SURVIVOR CURVE.. 30-SQUARE
NET SALVAGE PERCENT.. 0

1989	21,464.07	21,106	20,891	574	0.50	574
1990	1,200.58	1,141	1,129	71	1.50	47
1991	10,546.71	9,668	9,569	977	2.50	391
1992	2,982.99	2,635	2,608	375	3.50	107
1993	8,352.36	7,100	7,028	1,325	4.50	294
1994	801.20	654	647	154	5.50	28
1995	9,762.76	7,647	7,569	2,194	6.50	338
1996	5,132.79	3,850	3,811	1,322	7.50	176
1997	15,720.17	11,266	11,151	4,569	8.50	538
1998	23,463.35	16,033	15,869	7,594	9.50	799
1999	26,919.50	17,498	17,319	9,600	10.50	914
2000	1,581.43	975	965	616	11.50	54
2001	5,288.03	3,085	3,054	2,235	12.50	179
	133,215.94	102,658	101,610	31,606		4,439
	135,894.40	105,336	104,288	31,606		4,439

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.1 3.27

FULLY ACCRUED
NET SALVAGE PERCENT.. 0

1993	55,524.33	55,524	55,524			
	55,524.33	55,524	55,524			

AMORTIZED
SURVIVOR CURVE.. 25-SQUARE
NET SALVAGE PERCENT.. 0

1994	136,592.35	133,861	132,550	4,043	0.50	4,043
1995	72,694.12	68,332	67,663	5,031	1.50	3,354
1996	32,632.97	29,370	29,082	3,551	2.50	1,420
1997	42,373.35	36,441	36,084	6,289	3.50	1,797
1998	197,519.65	161,966	160,379	37,140	4.50	8,253
1999	33,156.89	25,862	25,609	7,548	5.50	1,372
2000	65,934.42	48,791	48,313	17,621	6.50	2,711
2001	78,513.97	54,960	54,422	24,092	7.50	3,212
2002	49,482.32	32,658	32,338	17,144	8.50	2,017
2003	14,974.55	9,284	9,193	5,781	9.50	609
2004	3,289.31	1,908	1,889	1,400	10.50	133
2005	14,525.70	7,844	7,767	6,759	11.50	588
2007	309,682.25	142,454	141,059	168,624	13.50	12,491
2008	49,068.53	20,609	20,407	28,661	14.50	1,977
2009	14,699.46	5,586	5,531	9,168	15.50	591
2010	22,472.51	7,641	7,566	14,906	16.50	903
2011	843.66	253	251	593	17.50	34
2012	13,832.36	3,596	3,561	10,272	18.50	555
2013	101,039.24	22,229	22,011	79,028	19.50	4,053
2014	279,299.07	50,274	49,782	229,518	20.50	11,196
2016	3.62			4	22.50	
2017	4,873.60	292	289	4,584	23.50	195
2018	181,764.65	3,635	3,599	178,165	24.50	7,272
	1,719,268.55	867,846	859,345	859,924		68,776
	1,774,792.88	923,370	914,869	859,924		68,776

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.5 3.88

FULLY ACCRUED
NET SALVAGE PERCENT.. 0

1998	6,534.64	6,535	6,535			
	6,534.64	6,535	6,535			

AMORTIZED
SURVIVOR CURVE.. 20-SQUARE
NET SALVAGE PERCENT.. 0

2000	151.16	140	140	11	1.50	7
2001	1,862.21	1,629	1,629	233	2.50	93
2003	12,378.12	9,593	9,593	2,785	4.50	619
2007	8,388.77	4,824	4,824	3,565	8.50	419
2008	17,351.93	9,110	9,110	8,242	9.50	868
	40,132.19	25,296	25,295	14,837		2,006
	46,666.83	31,831	31,830	14,837		2,006

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.4 4.30

SURVIVOR CURVE.. IOWA 20-S1
NET SALVAGE PERCENT.. +5

1957	44.11	42	42			
1965	2,210.71	2,100	2,100			
1969	4,001.40	3,801	3,801			
1971	515.06	489	489			
1972	318.60	303	303			
1973	735.44	699	699			
1974	3,790.08	3,601	3,601			
1975	51.23	49	49			
1976	5,254.44	4,992	4,992			
1977	609.27	579	579			
1978	1,866.00	1,773	1,773			
1979	413.65	390	393			
1981	2,630.61	2,415	2,499			
1982	87.29	79	83			
1983	517.20	461	491			
1984	2,005.72	1,763	1,905			
1985	7,885.69	6,821	7,462	29	1.79	16
1986	6,530.58	5,559	6,081	123	2.08	59
1987	40,902.79	34,234	37,451	1,407	2.38	591
1988	29,318.55	24,106	26,372	1,481	2.69	551
1989	150.07	121	132	11	3.00	4
1990	4,722.36	3,742	4,094	392	3.32	118
1991	54,939.13	42,693	46,705	5,487	3.64	1,507
1992	7,611.18	5,792	6,336	895	3.98	225
1993	13,371.65	9,953	10,888	1,815	4.33	419
1994	14,939.82	10,872	11,894	2,299	4.68	491
1995	13,744.73	9,760	10,677	2,380	5.05	471
1997	18,210.24	12,274	13,428	3,872	5.81	666
1998	20,679.60	13,546	14,819	4,827	6.21	777
1999	541.90	344	376	139	6.63	21
2000	2,661.89	1,636	1,790	739	7.06	105
2001	11,029.18	6,543	7,158	3,320	7.51	442
2008	1,594.91	661	723	792	11.28	70
2009	9,243.49	3,543	3,876	4,905	11.93	411
2012	5,307.42	1,487	1,627	3,415	14.10	242
2013	2,492.85	604	661	1,707	14.90	115
2015	38,073.44	6,095	6,668	29,502	16.63	1,774
2017	14,825.57	1,049	1,148	12,936	18.51	699
2018	37,775.97	897	981	34,906	19.50	1,790
	381,603.82	225,868	245,146	117,378		11,564

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.2 3.03

FULLY ACCRUED
NET SALVAGE PERCENT.. 0

1991	14.63	15	15			
1998	2,990,956.97	2,990,957	2,990,957			
	2,990,971.60	2,990,972	2,990,972			

AMORTIZED
SURVIVOR CURVE.. 20-SQUARE
NET SALVAGE PERCENT.. 0

1999	25,234.58	24,604	24,400	835	0.50	835
2000	31,654.70	29,281	29,038	2,617	1.50	1,745
2001	11,513.19	10,074	9,990	1,523	2.50	609
2002	27,028.83	22,299	22,114	4,915	3.50	1,404
2003	35,257.45	27,325	27,098	8,159	4.50	1,813
2004	1,086.53	788	781	305	5.50	55
2006	968.57	605	600	369	7.50	49
2007	4,182.18	2,405	2,385	1,797	8.50	211
2008	163,140.86	85,649	84,938	78,203	9.50	8,232
2009	9,142.11	4,343	4,307	4,835	10.50	460
2010	51,293.07	21,800	21,619	29,674	11.50	2,580
2011	11,128.21	4,173	4,138	6,990	12.50	559
2012	8,142.44	2,646	2,624	5,518	13.50	409
2013	13,687.02	3,764	3,733	9,954	14.50	686
2014	92,922.64	20,908	20,734	72,188	15.50	4,657
2015	7,135.08	1,249	1,239	5,896	16.50	357
2016	159,550.73	19,944	19,778	139,772	17.50	7,987
2017	609,508.57	45,713	45,333	564,175	18.50	30,496
2018	1,343,594.60	33,590	33,311	1,310,284	19.50	67,194
	2,606,171.36	361,160	358,160	2,248,011		130,338
	5,597,142.96	3,352,132	3,349,132	2,248,011		130,338

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.2 2.33

FULLY ACCRUED
NET SALVAGE PERCENT.. 0

1998	25,863.09	25,863	25,863			
	25,863.09	25,863	25,863			

AMORTIZED
SURVIVOR CURVE.. 20-SQUARE
NET SALVAGE PERCENT.. 0

1999	31,612.43	30,822	30,362	1,250	0.50	1,250
2000	35,305.46	32,658	32,171	3,134	1.50	2,089
2001	709.31	621	612	98	2.50	39
2003	212.74	165	163	50	4.50	11
2006	344.25	215	212	132	7.50	18
2009	1,052.69	500	493	560	10.50	53
2010	1,469.67	625	616	854	11.50	74
2011	4,396.25	1,649	1,624	2,772	12.50	222
2012	385.44	125	123	262	13.50	19
2013	1,061.46	292	288	774	14.50	53
2014	7,800.44	1,755	1,729	6,072	15.50	392
2015	14,987.62	2,623	2,584	12,404	16.50	752
2016	4,874.36	609	600	4,274	17.50	244
2017	3,581.09	269	265	3,316	18.50	179
2018	4,241.20	106	104	4,137	19.50	212
	112,034.41	73,034	71,945	40,089		5,607
	137,897.50	98,897	97,808	40,089		5,607

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.1 4.07

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Jersey Central Power & Light Company) Docket No. ER20-___-000

**DIRECT TESTIMONY
OF
MICHAEL T. FALEN**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael T. Falen 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 employed by FirstEnergy Service Company (the "Service Company") as the Director of Transmission Business Services in the FirstEnergy Utilities ("FEU") Finance Group within the Controller's Group of the FirstEnergy Service Company. In that position, my responsibilities include accounting, forecasting, and reporting for FirstEnergy's Transmission subsidiaries, which includes Jersey Central Power and Light Company ("JCP&L").

Q. WHEN YOU REFER TO THE FIRSTENERGY TRANSMISSION BUSINESS SERVICES, CONTROLLERS GROUP, FEU AND FET, WHAT DO YOU MEAN?

A. The FirstEnergy Transmission Business Services group is a section within the Controllers Group within the Service Company utilized for coordinating and/or standardizing business-related financial services throughout the FirstEnergy Transmission holding company system. The Transmission Business Services group functions, which are provided to the Service Company for the FirstEnergy associate companies, are under the leadership of the

FirstEnergy Controller and Chief Accounting Officer. FEU and FET are two reporting segments within the FirstEnergy holding company system, which include FirstEnergy's ten electric distribution companies, including JCP&L.

Q. PLEASE PROVIDE YOUR EDUCATION, PROFESSIONAL BACKGROUND AND RELEVANT EXPERIENCE.

A. My education, professional background and relevant experience are shown in Exhibit No. JCP-401.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this testimony on behalf of JCP&L, which is an affiliate of the Service Company and an indirect wholly owned subsidiary of FirstEnergy Corp.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony is submitted in support of JCP&L's filing with the Commission of a proposed transmission formula rate. The balance of my testimony is organized as follows.

- In Section II, I support JCP&L's filing by sponsoring the cost of service statements governed by Section 35.13 of the Commission's regulations and included, as applicable, with the filing.
- In Section III, I describe the budgeting process that produced the projections of transmission costs for rate year 2020.
- In Section IV, I describe how affiliate costs are direct-charged or allocated to JCP&L.

Q. ARE YOU SPONSORING ANY EXHIBITS IN ADDITION TO THIS TESTIMONY?

A. Yes. I am sponsoring Exhibit Nos. JCP-401 (Education and Experience); JCP-402 (Cost of Service Statements); and JCP-403 (Formula Rate with 2020 Data); JCP-404 (Cost of Service Statements Attestation); JCP-405 (FirstEnergy Service Agreement); JCP-406

(Revised and Amended Mutual Assistance Agreement); and JCP-407 (New Jersey Board of Public Utilities Order).

II. COST OF SERVICE STATEMENTS

Q. HAS JCP&L INCLUDED ANY COST OF SERVICE STATEMENTS WITH THIS FILING?

A. Yes. JCP&L is providing, and I am sponsoring, the cost of service statements described below. These statements are provided in Exhibit No. JCP-402. The cost of service statements along with the documents, testimony and exhibits accompanying this filing, together with JCP&L's publicly available FERC Form 1 information, comply with the Commission's cost support regulations and provide ample support for the reasonableness of the proposed formula rate charges. In addition, a copy of Statement BK (which is the same as the Formula Rate) with 2020 data in Excel format is provided as Exhibit No. JCP-403.

Q. WHAT PERIODS ARE USED FOR PERIOD I AND PERIOD II?

A. For Period I, JCP&L is using data from calendar year 2018. For Period II, JCP&L is using data from calendar year 2020, which is the first twelve-month period following the proposed January 1, 2020 effective date for the JCP&L transmission formula rate. The projections for Period II thus cover the period when the initial charges under the revised formula rate are proposed to be in effect.

Q. WHAT IS COMBINED STATEMENT BG/BH?

A. The combined Statement BG/BH shows JCP&L's revenues for Period I and Period II under its present stated rate and the proposed formula rate.

Q. WHAT IS STATEMENT BK?

A. Statement BK is a statement of JCP&L's fully allocated cost of service developed and shown for Period I and Period II. For Statement BK, JCP&L is providing the completed formula rate template for each period, in the same format that it proposes to provide as the "Annual Update" under its proposed formula rate protocols.

Q. HAS JCP&L INCLUDED THE ATTESTATION REQUIRED UNDER THE COMMISSION'S COST OF SERVICE REGULATIONS?

A. Yes. Exhibit No. JCP-404 is an attestation by me, the Director of Transmission Business Services of FirstEnergy, that, to the best of my knowledge, information, and belief, the cost of service statements and supporting data submitted in this filing are true, accurate, and current representations of Jersey Central Power & Light's books, budgets, or other corporate documents.

III. BUDGETING PROCESS

Q. PLEASE DESCRIBE THE BUDGETING PROCESS THAT PRODUCED THE PROJECTIONS OF TRANSMISSION COSTS FOR RATE YEAR 2020.

A. The projection of JCP&L's 2020 costs is based on FirstEnergy's budget process, which is designed to produce a reasonable and accurate forecast of the expected costs needed to provide reliable transmission service to its customers. FirstEnergy's process requires each business unit to assess changing business conditions and reflect the resulting financial impacts in its operating budget. Each year, JCP&L assesses and forecasts the transmission system additions and enhancements required as part of PJM's Regional Transmission Expansion Plan ("RTEP") process and FirstEnergy's Energizing the Future ("EtF") methodology, which provides guidance on Reliability Enhancement projects. The forecasts used to prepare the statements I am sponsoring were based on JCP&L's budgeting process. JCP&L's O&M and capital investment forecast for 2020 was prepared in connection with these processes.

Q. HOW DOES THE BUDGET PROCESS START?

A. The budget process starts with the development of the corporate planning calendar, which provides the timeline and framework for each business unit to develop its O&M and capital investment forecast. The O&M and capital budgeting process has three phases:

Phase 1 - project identification and cost estimation;

Phase 2 - business unit budget creation; and

Phase 3 - senior management review and approval.

Q. DESCRIBE PHASE ONE OF THE BUDGET PROCESS.

A. During this phase, projects are evaluated based on the FirstEnergy EtF methodology posted on PJM's website or FirstEnergy's Planning Criteria. Projects are identified to address customer reliability, asset condition, system performance, operational flexibility or system enhancements required as part of PJM's RTEP process. Cost forecasts are prepared based on the project's planned scope and schedule and include estimates for internal and external labor resources, land acquisitions, materials and equipment. Projects initially identified for the capital budget are reviewed with FE Utilities senior management as part of the business unit's capital portfolio review process.

Q. DESCRIBE PHASE TWO OF THE BUDGET PROCESS.

A. In phase two, each business unit, in conjunction with its business services support team, develops its O&M and capital budgets on a schedule consistent with the corporate planning calendar. Each budget is built from the "bottom up" by individual cost component, including employee labor, contractor costs, materials and equipment. The schedule is designed to allow sufficient time for the establishment of budget targets, budget entry and processing, as well as internal reviews and validation by business services personnel before the budgets are submitted to senior management.

Q. DESCRIBE PHASE THREE OF THE BUDGET PROCESS.

A. Phase three consists of the senior management review and approval process. This process includes an earnings and cash forecast as well as detailed reporting and analysis to support the O&M and capital forecasts, and frequent review and communication with senior management.

Q. DOES THE BUDGET PROCESS YOU HAVE DESCRIBED ENSURE THAT ACTUAL RESULTS WILL ALWAYS MATCH BUDGETS?

A. No. The O&M and capital budgets are intended to reflect a reasonable forecast of the costs that JCP&L is expected to incur in order to provide reliable transmission service to its customers. Circumstances may arise that necessitate deviations in the timing and level of planned expenditures—including required changes in a project's scope and schedule, emergent projects, transmission outage restrictions, and weather-related impacts.

Q. WHAT IS JCP&L'S CURRENT ESTIMATE OF FUTURE TRANSMISSION INVESTMENT COSTS?

A. JCP&L estimates approximately $175 million of transmission capital investment in 2020 to address system needs.

IV. AFFILIATE COSTS

Q. UNDER WHAT AGREEMENTS ARE AFFILIATE COSTS CHARGED TO JCP&L?

A. There are two such agreements. The first, the FirstEnergy Service Agreement ("Service Agreement") governs costs charged by the Service Company for the general administrative, management, and related services that it will provide to JCP&L. A copy of the Service Agreement is attached as Exhibit No. JCP-405. The second, the Amended and Restated Mutual Assistance Agreement ("Mutual Assistance Agreement"), governs costs charged to JCP&L by other FirstEnergy operating companies for operational services that will be provided to JCP&L. A copy of the Mutual Assistance Agreement is attached as Exhibit No. JCP-406. I explain in detail below how costs are allocated to JCP&L under each of these agreements.

V. COST ALLOCATION UNDER THE SERVICE AGREEMENT

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 and other services to FirstEnergy associate companies. The FirstEnergy System can leverage its economies of scale to more efficiently utilize its resources by providing such services from centralized groups within the Service Company. In addition, it has been long understood 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. Among other things, the Service Company has a greater degree of bargaining power with suppliers than would each FirstEnergy associate company 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 THE FIRSTENERGY ASSOCIATE COMPANIES, INCLUDING JCP&L.

A. The Service Company provides various corporate, managerial and administrative support services to FirstEnergy and its associate companies, including Jersey Central Power & Light, in the following areas: administrative services, claims, communications, controllers, credit management, energy delivery and customer service, economic development, enterprise risk management, governmental affairs, human resources, industrial relations, information services, insurance services, internal audit, legal, performance planning, rates and regulatory affairs, real estate, supply chain, technologies support, telecommunications support, transmission and distribution technical services, and treasury. A full list and description of the services provided by the Service Company are set forth in Exhibit A to the Service Agreement.

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 company, such as, for instance, JCP&L, because those costs are related to services performed solely for Jersey Central Power & Light. 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 costs of the service cannot be reasonably identified with any individual associate company or companies.

Q. PLEASE FURTHER CLARIFY WHAT YOU MEAN BY "DIRECTLY CHARGED."

A. When I say that a cost is "directly charged," I mean 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 required by the Service Agreement to be charged directly to the associate company receiving the goods or services to the extent that costs can be reasonably identified and related to a particular associate company and a particular transaction, even when more than one associate company is receiving the same goods or 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 mean that the charges are not capable of being directly charged to a single associate company. In such cases, one could also say that such costs are "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 charged or allocated." This combination of terms may create confusion that I attempt 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. Direct costs are costs that can be specifically identified with a 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 recipient associate company; otherwise 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 service. This includes but is not limited to overhead costs (e.g., payroll, stores handling, construction), administrative and general expenses, and various taxes. Costs incidental or related to indirect items are also classified as indirect costs and are allocated across cost centers. Indirect costs may be directly charged if reasonably identifiable to a 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. These costs are fully loaded, meaning that they include the actual direct costs incurred to provide a service plus the indirect costs (such as appropriate overheads) incidental or related to a service that are allocated.

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. Whether the Service Company is charged directly or indirectly is dependent on the circumstances. If the costs can be reasonably identified and related to the particular transaction for the individual associate companies, then the costs are directly charged to each associate company in the group. If they cannot, then the costs must be indirectly charged using an appropriate cost allocation methodology. However, whenever practicable (to the extent excessive effort or expense is not required), costs that can be identified as related to a service provided to an associate company are directly charged to that associate company. But where the costs cannot be so identified, they are indirectly charged using an approved cost allocation methodology.

Q. WHAT DO YOU MEAN BY A "COST ALLOCATION METHODOLOGY"?

A. A "cost allocation methodology" is a method or process for distributing costs for services rendered that cannot be directly charged to a single associate company. In such instances, the costs must be 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 Service Agreement, and in compliance with the standards promulgated by the Commission under PUHCA 2005 (including cost allocation methodologies previously approved by the SEC under the Public Utility Holding Company Act of 1935). The cost allocation methodologies are also listed in the Service Company's FERC Form 60, which the Service Company uses to report to the Commission annually. The Service Company 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; it renders services at cost to FirstEnergy and its associate companies. Therefore, all its costs must be fairly and equitably distributed to FirstEnergy and its associate companies. The cost allocation methodologies are used to accurately distribute those costs that cannot be directly charged to an associate company, and, therefore, must be indirectly charged to, and among, FirstEnergy and its associate companies. The cost allocation methodology used with respect to any 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 that are to be indirectly charged to and among FirstEnergy and its associate companies.

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 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. The cost allocation methodologies are the same today as those approved in 2003 by the SEC and continued under the Commission's jurisdiction pursuant to PUHCA 2005.

Q. DOES ANY ASPECT OF THE COST ALLOCATION PROCESS CHANGE FROM TIME TO TIME?

A. While the cost allocation methodologies themselves do not change, the data inputs required to apply the cost allocation methodologies do change on an annual basis. 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 the FirstEnergy utilities' plant, operations and maintenance expenses, and revenues. These data will change from year to year.

Q. HOW WILL COSTS BE CHARGED 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" when possible, for those costs originating within the Service Company that relate to services that can clearly be identified as benefiting only JCP&L, or (ii) "indirectly charged" using appropriate general and/or specific cost allocation methodologies associated with the services rendered, where the identification of such costs to any single associate company cannot be reasonably determined but where it can be determined that such costs benefit JCP&L and one or more of the other FirstEnergy associate companies.

VI. COST ALLOCATION UNDER THE MUTUAL ASSISTANCE AGREEMENT

Q. WHAT IS THE MUTUAL ASSISTANCE AGREEMENT AND WHAT SERVICES WILL BE PROVIDED TO JERSEY CENTRAL POWER & LIGHT UNDER THAT AGREEMENT?

A. The Mutual Assistance Agreement is an agreement among the FirstEnergy operating companies pursuant to which they provide non-power goods and services to each other. JCP&L is a party to the Mutual Assistance Agreement.

Q. HOW ARE COSTS CHARGED TO JCP&L UNDER THE MUTUAL ASSISTANCE AGREEMENT?

A. The Mutual Assistance Agreement requires that all services to JCP&L be provided at cost, and that all goods sold to JCP&L be priced at cost less depreciation. As is the case under the Service Agreement, whenever practicable (*i.e.*, to the extent excessive effort or expense is not required), costs that can be identified as related to a service provided to a company are directly charged to that company.

Q. HOW ARE COSTS THAT CANNOT BE DIRECTLY CHARGED ALLOCATED TO JCP&L?

A. Attachment I to the Mutual Assistance Agreement establishes the indirect allocation methodology that applies to each type of service provided, and Attachment II provides a detailed description of each of the indirect allocation methodologies included in Attachment I. These methodologies are identical to the similarly named allocation methodologies in the Service Agreement—although not all 18 methodologies used in the Service Agreement apply to the Mutual Assistance Agreement.

Q. IS THERE ANYTHING ELSE THAT YOU WISH TO COMMENT ON?

A. Yes. Attached hereto as Exhibit JCP-407 is a copy of an order issued by the New Jersey Board of Public Utilities in NJ BPU Docket No. EM19030357.

Q. WHY ARE YOU INCLUDING THIS ORDER AS AN EXHIBIT TO YOUR TESTIMONY?

A. In the order, the New Jersey BPU directed JCP&L to, among other things, provide FERC a copy of this Order in that next rate proceeding.

VII. CONCLUSION

Q. DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jersey Central Power & Light Company) Docket No. ER20-___-000

DECLARATION OF MICHAEL T. FALEN

I, Michael T. Falen, identified in the foregoing prepared direct testimony, do hereby declare under penalty of perjury, that I prepared or caused such testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Executed on October 30, 2019.

/s/ Michael T. Falen
Michael T. Falen

MICHAEL T. FALEN

Education, Professional Background and Relevant Experience

Mr. Falen has a B.S. degree in Finance and an MBA, both from The University of Akron. Prior to joining FirstEnergy in 2007, he was employed by Progressive Insurance for five and a half years.

Mr. Falen has been employed by affiliates of FirstEnergy Corp. for over 11 years in various accounting, finance and analyst positions within FirstEnergy Service Company (the "Service Company") and FirstEnergy Utilities. From 2007 through 2009 Mr. Falen held the position of Analyst, Business Analytics for the Service Company. From 2010 through 2011 Mr. Falen held the position of Manager, Business Services for Ohio Edison. From 2011 through 2012 Mr. Falen held the position of Manager, Business Services for The Illuminating Company. From 2012 through 2013 Mr. Falen held the position of Manager, Business Services for Ohio Operations. From 2013 through 2016 Mr. Falen held the position of Manager, FES Accounting, Reporting and Settlements.

In February 2016, Mr. Falen was named Director, FirstEnergy Transmission Business Services. In his current role in the Controller's group, he is responsible for the finance and accounting activities related to FirstEnergy's Regulated Transmission segment. His primary responsibilities include accounting, budgeting and forecasting and management reporting.

PERIOD I

JERSEY CENTRAL POWER & LIGHT COMPANY
REVENUE DATA TO REFLECT CHANGED RATES AND PRESENT RATES
TWELVE MONTHS ENDED 12/31/18

Line No.	2018 Revenue Reflecting Present Rate		2018 Revenue Reflecting Proposed Rate		Difference (Proposed minus Present)		Change
	Monthly	Annual (1)	Monthly	Annual (1)	Monthly	Annual	%
1	$ 13,050,494	$ 156,605,928	$ 12,477,384	$ 149,728,612	$ (573,110)	$ (6,877,316)	-4.39%

Note:
(1) Refer to WP-01; Includes NITS and TEC

WP-01

BG BH Support

Line				Units
1	JCPL Zone		5,721.0	MW
2	Stated NITS Rate	$	23,597.3	Per MW Per Year
3	Stated NITS Revenue [(1)]	$	135,000,000	Dollars
4	JCPL Zone		5,721.0	MW
5	Proposed NITS Rate	$	22,316.16	Per MW Per Year
6	Proposed NITS Revenue	$	127,670,728	Dollars
7	Stated TEC Revenue [(1)]	$	21,605,928	Dollars
8	Proposed TEC Revenue	$	22,057,885	Dollars

Note:

(1) Uncontested settlement approved by FERC on February 20, 2018 under ER17-217 included a stated NITS revenue requirement of $135,000,000 and TEC revenue of $21,605,928.

Period I

Statement BK
Attachment H-4A
page 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2018

Jersey Central Power & Light

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 42, col 5]					$ 150,538,534
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 451	(page 4, line 29)	-	TP	0.99757	-
3	Account No. 454	(page 4, line 30)	-	TP	0.99757	-
4	Account No. 456	(page 4, line 31)	811,892	TP	0.99757	809,922
5	Revenues from Grandfathered Interzonal Transactions		-	TP	0.99757	-
6	Revenues from service provided by the ISO at a discount		-	TP	0.99757	-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	22,111,539	TP	0.99757	22,057,885
8	TOTAL REVENUE CREDITS (sum lines 2-7)		22,923,431			22,867,807
9	True-up Adjustment with Interest	(Attachment 13, Line 28) enter negative				-
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)				$ 127,670,728

Line No.				Total
	DIVISOR			
11	1 Coincident Peak (CP) (MW)		(Note A)	5,721.0
12	Average 12 CPs (MW)		(Note CC)	4,175.4

Line No.			Total
13	Annual Rate ($/MW/Yr)	(line 10 / line 11)	22,316.16

Line No.			Peak Rate Total	Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	30,576.89	30,576.89
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	2,548.07	2,548.07
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	588.02	588.02
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	117.60	84.00
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	7.35	3.49

Period I

Statement BK
Attachment H-4A
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Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2018

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)	63,882,682	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,537,977,607	TP	0.99757	1,534,245,644
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	4,687,877,177	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	353,103,996	W/S	0.08597	30,357,743
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	0.08597	-
6	TOTAL GROSS PLANT (sum lines 1-5)		6,642,841,462	GP=	23.553%	1,564,603,387
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	42,768,950	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	390,711,054	TP	0.99757	389,762,978
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	1,426,361,180	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	208,940,201	W/S	0.08597	17,963,413
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	0.08597	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,068,781,384			407,726,391
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	21,113,732			
14	Transmission	(line 2- line 8)	1,147,266,554			1,144,482,666
15	Distribution	(line 3 - line 9)	3,261,515,997			
16	General & Intangible	(line 4 - line 10)	144,163,796			12,394,330
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		4,574,060,079	NP=	25.292%	1,156,876,996
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 1, Col. 1 (Notes C & F)	-	NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 1, Col. 2 (Note C & F)	(382,163,846)	DA	1.00000	(382,163,846)
21	Account No. 283 (enter negative)	Attachment 5, Line 1, Col. 3 (Notes C & F)	(7,424,432)	DA	1.00000	(7,424,432)
22	Account No. 190	Attachment 5, Line 1, Col. 4 (Notes C & F)	40,797,698	DA	1.00000	40,797,698
23	Account No. 255 (enter negative)	Attachment 5, Line 1, Col. 5 (Notes C & F)	-	DA	1.00000	-
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 6, Col. 6 (Notes C & Y)	-	DA	1.00000	-
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 9, Col. 6 (Notes C & Y)	-	DA	1.00000	-
26	CWIP	216.b (Notes X & Z)	-	DA	1.00000	-
27	Unamortized Abandoned Plant	Attachment 16, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
28	TOTAL ADJUSTMENTS (sum lines 19-27)		(348,790,580)			(348,790,580)
29	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)	-	TP	0.99757	-
30	WORKING CAPITAL (Note H)					
31	CWC	1/8*(Page 3, Line 14 minus Page 3, Line 11)	10,274,277.43			4,206,004.65
32	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)	-	TE	0.94226	-
33	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)	1,792,070	GP	0.23553	422,090
34	TOTAL WORKING CAPITAL (sum lines 31 - 33)		12,066,347			4,628,095
35	RATE BASE (sum lines 18, 28, 29, & 34)		4,237,335,845			812,714,511

Period I

Statement BK
Attachment H-4A
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Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2018

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b	27,923,401	TE	0.94226	26,311,183
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		111,179	DA	1.00000	111,179
3	Less Account 565	321.96.b	235,050	DA	1.00000	235,050
4	Less Account 566	321.97.b	(5,175,022)	DA	1.00000	(5,175,022)
5	A&G	323.197.b	56,826,698	W/S	0.08597	4,885,615
6	Less FERC Annual Fees		-	W/S	0.08597	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		5,478,092	W/S	0.08597	470,973
8	Plus Transmission Related Reg. Comm. Exp. (Note I)		-	TE	0.94226	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 11 (Note C)	3,268,441	DA	1.00000	3,268,441
10	Common	356.1	-	CE	0.08597	-
11	Account 566 Amortization of Regulatory Assets	321.97.b (notes)	-	DA	1.00000	-
12	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 11	(5,175,022)	DA	1.00000	(5,175,022)
13	Total Account 566 (sum lines 11 & 12, ties to 321.97.b)		(5,175,022)			(5,175,022)
14	TOTAL O&M (sum lines 1, 5,8, 9, 10, 13 less 2, 3, 4, 6, 7)		82,194,219			33,648,037
	DEPRECIATION AND AMORTIZATION EXPENSE					
15	Transmission	336.7.b (Note U)	34,074,902	TP	0.99757	33,992,218
16	General & Intangible	336.1.f & 336.10.f (Note U)	18,821,113	W/S	0.08597	1,618,125
17	Common	336.11.b (Note U)	-	CE	0.08597	-
18	Amortization of Abandoned Plant	Attachment 16, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
19	TOTAL DEPRECIATION (sum lines 15 -18)		52,896,015			35,610,343
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
20	Payroll	263.i (Attachment 7, line 1z)	5,793,391	W/S	0.08597	498,081
21	Highway and vehicle	263.i (Attachment 7, line 2z)	2,595	W/S	0.08597	223
22	PLANT RELATED					
23	Property	263.i (Attachment 7, line 3z)	5,952,322	GP	0.23553	1,401,964
24	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
25	Other	263.i (Attachment 7, line 5z)	-	GP	0.23553	-
26	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	0.23553	-
27	TOTAL OTHER TAXES (sum lines 20 - 26)		11,748,308			1,900,268
	INCOME TAXES	(Note K)				
28	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		28.11%			
29	CIT=(T/1-T) * (1-(WCLTD/R)) =		25.14%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
30	1 / (1 - T) = (from line 28)		1.3910			
31	Amortized Investment Tax Credit (266.8.f) (enter negative)		(131,199)			
32	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) (Note D)		240,356			
33	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) (Note E)		(3,248,929)			
34	Income Tax Calculation = line 29 * line 39		87,567,520	NA		16,795,316
35	ITC adjustment (line 30 * line 31)		(182,499)	NP	0.25292	(46,158)
36	Permanent Differences and AFUDC Equity Tax Adjustment (line 30 * line 32)		334,339	DA	1.00000	334,339
37	(Excess)/Deficient Deferred Income Tax Adjustment (line 30 * line 33)		(4,519,306)	DA	1.00000	(4,519,306)
38	Total Income Taxes	sum lines 34 through 37	83,200,053			12,564,190
39	RETURN	[Rate Base (page 2, line 35) * Rate of Return (page 4, line 25, col. 6)]	348,364,081.45	NA		66,815,696
40	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)	(sum lines 14, 19, 27, 38, 39)	578,402,677			150,538,534
41	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)	0			0
42	GROSS REV. REQUIREMENT	(line 40 + line 41)	578,402,677			150,538,534

Period I

Statement BK
Attachment H-4A
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Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2018

Jersey Central Power & Light

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (page 2, line 2, column 3)						1,537,977,607		
2	Less transmission plant excluded from ISO rates (Note M)						-		
3	Less transmission plant included in OATT Ancillary Services (Note N)						3,731,963		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,534,245,644		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	0.99757		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (page 3, line 1, column 3)						27,923,401		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,548,218		
8	Included transmission expenses (line 6 less line 7)						26,375,183		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.94455		
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	0.99757		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.94226		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	-	0.00	-				
13	Transmission	354.21.b	7,056,263	1.00	7,039,141				
14	Distribution	354.23.b	58,655,533	0.00	-		W&S Allocator		
15	Other	354.24, 354.25, 354.26.b	16,163,483	0.00	-		($ / Allocation)		
16	Total (sum lines 12-15)		81,875,279		7,039,141	=	0.08597	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)								
			$		% Electric		W&S Allocator		
17	Electric	200.3.c	-		(line 17 / line 20)		(line 16, col. 6)		CE
18	Gas	201.3.d	-		1.00000	*	0.08597	=	0.08597
19	Water	201.3.e	-						
20	Total (sum lines 17 - 19)		-						
	RETURN (R)						$		
21	Preferred Dividends (118.29c) (positive number)						-		
					Cost				
			$	%	(Note P)		Weighted		
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)		1,614,161,520	51%	0.0575		0.0294	=WCLTD	
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)		-	0%	0.0000		0.0000		
24	Common Stock Attachment 8, Line 14, Col. 6) (Note X)		1,546,933,179	49%	0.1080		0.0529		
25	Total (sum lines 22-24)		3,161,094,699				0.0822	=R	
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)					
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						-		
27	b. Bundled Sales for Resale included in Divisor on page 1						-		
28	Total of (a)-(b)						-		
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)		(300.17.b)				-		
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		(300.19.b)				-		
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)		(330.x.n)				811,892		

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2018

Jersey Central Power & Light

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT.
B	Prepayments shall exclude prepayments of income taxes.
C	Transmission-related only
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of regulatory assets (page 3, line 11, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 30).

Inputs Required:	FIT =	21.00%	
	SIT=	9.00%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA., and related to generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = Attachment 10, Column (j) total. Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by its own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Page 4, Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-mo period at the time of the filing.

Period I

Statement BK
Attachment H-4A, Attachment 1
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For the 12 months ended 12/31/2018

Schedule 1A Rate Calculation

1	$ 1,548,218	Attachment H-4A, Page 4, Line 7
2	$ 100,751	Revenue Credits for Sched 1A - Note A
3	$ 1,447,467	Net Schedule 1A Expenses (Line 1 - Line 2)
4	23,136,944	Annual MWh in JCP&L Zone - Note B
5	$ 0.0626	Schedule 1A rate $/MWh (Line 3/ Line 4)

Note:

A Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of JCP&L's zone during the year used to calculate rates under Attachment H-4A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the JCP&L zone. Data from RTO settlement systems for the calendar year prior to the rate year.

Period I

Statement BK
Attachment H-4A, Attachment 2
page 1 of 1
For the 12 months ended 12/31/2018

Incentive ROE Calculation

Return Calculation

			Source Reference	
1	Rate Base		Attachment H-4A, page 2, Line 35, Col. 5	812,714,511
2	Preferred Dividends	enter positive	Attachment H-4A, page 4, Line 21, Col. 6	0
	Common Stock			
3	Proprietary Capital		Attachment 8, Line 14, Col. 1	3,355,558,621
4	Less Preferred Stock		Attachment 8, Line 14, Col. 2	0
5	Less Accumulated Other Comprehensive Income Account 219		Attachment 8, Line 14, Col. 4	-2,273,566
6	Less Account 216.1 & Goodwill		Attachment 8, Line 14, Col. 3 & 5	1,810,899,008
7	Common Stock		Attachment 8, Line 14, Col. 6	1,546,933,179
	Capitalization			
8	Long Term Debt		Attachment H-4A, page 4, Line 22, Col. 3	1,614,161,520
9	Preferred Stock		Attachment H-4A, page 4, Line 23, Col. 3	0
10	Common Stock		Attachment H-4A, page 4, Line 24, Col. 3	1,546,933,179
11	Total Capitalization		Attachment H-4A, page 4, Line 25, Col. 3	3,161,094,699
12	Debt %	Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 4	51.0634%
13	Preferred %	Preferred Stock	Attachment H-4A, page 4, Line 23, Col. 4	0.0000%
14	Common %	Common Stock	Attachment H-4A, page 4, Line 24, Col. 4	48.9366%
15	Debt Cost	Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 5	0.0575
16	Preferred Cost	Preferred Stock	Attachment H-4A, page 4, Line 23, Col. 5	0.0000
17	Common Cost	Common Stock		0.1080
18	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 12 * Line 15)	0.0294
19	Weighted Cost of Preferred	Preferred Stock	(Line 13 * Line 16)	0.0000
20	Weighted Cost of Common	Common Stock	(Line 14 * Line 17)	0.0529
21	Rate of Return on Rate Base (ROR)		(Sum Lines 18 to 20)	**0.0822**
22	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 21)**	**66,815,696**

Income Taxes

	Income Tax Rates		
23	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	Attachment H-4A, page 3, Line 28, Col. 3	28.11%
24	CIT=(T/1-T) * (1-(WCLTD/R)) =	Calculated	25.14%
25	1 / (1 - T) = (from line 23)	Attachment H-4A, page 3, Line 30, Col. 3	1.3910
26	Amortized Investment Tax Credit (266.8.f) (enter negative)	Attachment H-4A, page 3, Line 31, Col. 3	(131,198.84)
27	Tax Effect of Permanent Differences and AFUDC Equity	Attachment H-4A, page 3, Line 32, Col. 3	240,356.04
28	(Excess)/Deficient Deferred Income Taxes	Attachment H-4A, page 3, Line 33, Col. 3	(3,248,929.35)
29	Income Tax Calculation	(line 22 * line 24)	16,795,316.00
30	ITC adjustment	Attachment H-4A, page 3, Line 35, Col. 5	(46,157.98)
31	Permanent Differences and AFUDC Equity Tax Adjustment	Attachment H-4A, page 3, Line 36, Col. 5	334,338.62
32	(Excess)/Deficient Deferred Income Tax Adjustment	Attachment H-4A, page 3, Line 37, Col. 5	(4,519,306.37)
33	Total Income Taxes	Sum lines 29 to 32	12,564,190.27

Increased Return and Taxes

34	Return and Income taxes with increase in ROE	(Line 22 + Line 33)	79,379,886.35
35	Return without incentive adder	Attachment H-4A, Page 3, Line 39, Col. 5	66,815,696.08
36	Income Tax without incentive adder	Attachment H-4A, Page 3, Line 38, Col. 5	12,564,190.27
37	Return and Income taxes without increase in ROE	Line 35 + Line 36	79,379,886.35
38	Return and Income taxes with increase in ROE	Line 34	79,379,886.35
39	Incremental Return and incomes taxes for increase in ROE	Line 38 - Line 37	-
40	Rate Base	Line 1	812,714,510.80
41	Incremental Return and incomes taxes for increase in ROE divided by rate base	Line 39 / Line 40	-

Notes:

Line 17 to include an incentive ROE that is used only to determine the increase in return and incomes taxes associated with a specific increase in ROE. Any actual ROE incentive must be approved by the Commission. Until an ROE incentive is approved, line 17 will reflect the current ROE.

Period I

Statement BK
Attachment H-4A, Attachment 3
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For the 12 months ended 12/31/2018

Gross Plant Calculation

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2017		60,782,490	1,486,829,006	4,587,566,829	101,231,608	235,068,084	-	6,471,478,017
2	January	2018		60,776,240	1,489,444,330	4,597,039,701	101,938,787	237,181,426	-	6,486,380,484
3	February	2018		60,777,536	1,521,115,293	4,605,197,152	103,047,243	239,854,121	-	6,529,991,345
4	March	2018		60,777,536	1,526,702,490	4,688,747,271	102,945,483	241,917,978	-	6,621,090,758
5	April	2018		60,777,536	1,528,903,737	4,665,498,180	102,847,790	244,477,556	-	6,602,504,799
6	May	2018		60,777,536	1,542,505,860	4,688,451,517	103,711,012	244,849,994	-	6,640,295,919
7	June	2018		60,777,536	1,548,406,825	4,696,195,735	104,001,482	252,183,213	-	6,661,564,791
8	July	2018		60,777,536	1,546,307,356	4,694,385,282	104,279,390	251,940,992	-	6,657,690,556
9	August	2018		60,777,536	1,549,987,009	4,724,826,102	105,468,473	252,577,460	-	6,693,636,580
10	September	2018		60,777,536	1,551,714,551	4,732,831,049	105,796,429	254,498,287	-	6,705,617,852
11	October	2018		60,777,536	1,552,999,976	4,742,533,476	106,104,044	255,514,719	-	6,717,929,751
12	November	2018		60,777,536	1,564,336,896	4,755,265,479	106,386,937	256,241,469	-	6,743,008,317
13	December	2018		101,140,774	1,584,455,573	4,763,865,525	117,152,122	259,135,845	-	6,825,749,839
14	**13-month Average**		**[A] [C]**	**63,882,682**	**1,537,977,607**	**4,687,877,177**	**104,993,138**	**248,110,858**	**-**	**6,642,841,462**

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
			[B]	205.46.g	207.58.g	207.75.g	205.5.g	207.99.g	356.1	
15	December	2017		60,782,490	1,486,832,416	4,587,612,486	101,231,608	237,025,548		6,473,484,548
16	January	2018		60,776,240	1,489,447,740	4,597,085,358	101,938,787	239,138,890		6,488,387,015
17	February	2018		60,777,536	1,521,118,703	4,605,242,809	103,047,243	241,811,585		6,531,997,876
18	March	2018		60,777,536	1,526,705,900	4,688,792,928	102,945,483	243,875,442		6,623,097,289
19	April	2018		60,777,536	1,528,907,147	4,665,543,837	102,847,790	246,435,020		6,604,511,330
20	May	2018		60,777,536	1,542,509,270	4,688,497,174	103,711,012	246,807,458		6,642,302,450
21	June	2018		60,777,536	1,548,410,235	4,696,241,392	104,001,482	254,140,677		6,663,571,322
22	July	2018		60,777,536	1,546,310,766	4,694,430,939	104,279,390	253,898,456		6,659,697,087
23	August	2018		60,777,536	1,549,990,419	4,724,871,759	105,468,473	254,534,924		6,695,643,111
24	September	2018		60,777,536	1,551,717,961	4,732,876,706	105,796,429	256,455,751		6,707,624,383
25	October	2018		60,777,536	1,553,003,386	4,742,579,133	106,104,044	257,472,183		6,719,936,282
26	November	2018		60,777,536	1,564,340,306	4,755,311,136	106,386,937	258,198,933		6,745,014,848
27	December	2018		101,140,774	1,584,458,983	4,763,911,182	117,152,122	261,093,309		6,827,756,370
28	13-month Average			63,882,682	1,537,981,018	4,687,922,834	104,993,138	250,068,321	-	6,644,847,993

Asset Retirement Costs

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
			[B]	205.44.g	207.57.g	207.74.g	company records	207.98.g	company records
29	December	2017			3,410	45,657		1,957,464	
30	January	2018			3,410	45,657		1,957,464	
31	February	2018			3,410	45,657		1,957,464	
32	March	2018			3,410	45,657		1,957,464	
33	April	2018			3,410	45,657		1,957,464	
34	May	2018			3,410	45,657		1,957,464	
35	June	2018			3,410	45,657		1,957,464	
36	July	2018			3,410	45,657		1,957,464	
37	August	2018			3,410	45,657		1,957,464	
38	September	2018			3,410	45,657		1,957,464	
39	October	2018			3,410	45,657		1,957,464	
40	November	2018			3,410	45,657		1,957,464	
41	December	2018			3,410	45,657		1,957,464	
42	13-month Average			-	3,410	45,657	-	1,957,464	-

Notes:

[A] Taken to Attachment H-4A, page 2, lines 1-6, Col. 3

[B] Reference for December balances as would be reported in FERC Form 1.

[C] Balance excludes Asset Retirements Costs

Period I

Statement BK
Attachment H-4A, Attachment 4
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For the 12 months ended 12/31/2018

Accumulated Depreciation Calculation

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2017		39,071,764	381,113,858	1,397,338,452	73,305,978	129,192,537	-	2,020,022,589
2	January	2018		39,170,488	381,691,022	1,401,410,013	73,865,309	130,068,726	-	2,026,205,558
3	February	2018		39,269,206	383,086,989	1,406,128,218	74,448,101	130,963,360	-	2,033,895,874
4	March	2018		39,367,926	384,838,855	1,411,956,788	75,048,240	131,520,824	-	2,042,732,633
5	April	2018		39,466,646	386,858,452	1,416,707,708	75,640,564	132,760,321	-	2,051,433,691
6	May	2018		39,565,366	388,684,276	1,422,270,449	76,238,784	133,634,405	-	2,060,393,280
7	June	2018		39,664,085	390,397,700	1,427,807,751	76,845,564	131,070,710	-	2,065,785,810
8	July	2018		39,762,805	392,239,479	1,433,525,995	77,400,718	132,670,097	-	2,075,599,094
9	August	2018		39,861,525	394,322,435	1,438,549,921	77,964,983	131,527,325	-	2,082,226,189
10	September	2018		39,960,245	396,444,601	1,439,670,732	78,539,664	131,427,522	-	2,086,042,764
11	October	2018		40,058,965	397,991,267	1,444,259,657	79,119,300	133,359,719	-	2,094,788,909
12	November	2018		40,157,685	399,837,902	1,449,940,013	79,702,897	134,307,076	-	2,103,945,573
13	December	2018		80,619,643	401,736,860	1,453,129,638	80,339,973	135,259,911	-	2,151,086,026
14	**13-month Average**		[A] [C]	**42,768,950**	**390,711,054**	**1,426,361,180**	**76,804,621**	**132,135,579**	**-**	**2,068,781,384**

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
			[B]	219.20-24.c	219.25.c	219.26.c	200.21.c	219.28.c	356.1	
15	December	2017		39,071,764	381,115,314	1,397,364,595	73,305,978	129,821,389		2,020,679,041
16	January	2018		39,170,488	381,692,481	1,401,436,230	73,865,309	130,706,784		2,026,871,292
17	February	2018		39,269,206	383,088,453	1,406,154,509	74,448,101	131,610,623		2,034,570,891
18	March	2018		39,367,926	384,840,323	1,411,983,152	75,048,240	132,177,292		2,043,416,933
19	April	2018		39,466,646	386,859,923	1,416,734,147	75,640,564	133,425,995		2,052,127,275
20	May	2018		39,565,366	388,685,751	1,422,296,961	76,238,784	134,309,285		2,061,096,147
21	June	2018		39,664,085	390,399,179	1,427,834,337	76,845,564	131,754,794		2,066,497,960
22	July	2018		39,762,805	392,240,962	1,433,552,655	77,400,718	133,363,386		2,076,320,526
23	August	2018		39,861,525	394,323,923	1,438,576,654	77,964,983	132,229,820		2,082,956,905
24	September	2018		39,960,245	396,446,092	1,439,697,539	78,539,664	132,139,223		2,086,782,763
25	October	2018		40,058,965	397,992,763	1,444,286,538	79,119,300	134,080,625		2,095,538,191
26	November	2018		40,157,685	399,839,401	1,449,966,968	79,702,897	135,037,188		2,104,704,138
27	December	2018		80,619,643	401,738,363	1,453,156,667	80,339,973	135,999,228		2,151,853,874
28	13-month Average			42,768,950	390,712,533	1,426,387,766	76,804,621	132,819,664	-	2,069,493,534

Reserve for Depreciation of Asset Retirement Costs

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
			[B]	Company Records	Company Records	Company Records	Company Records	Company Records	Company Records
29	December	2017			1,455	26,143		628,853	
30	January	2018			1,459	26,217		638,058	
31	February	2018			1,463	26,291		647,263	
32	March	2018			1,467	26,365		656,469	
33	April	2018			1,471	26,438		665,674	
34	May	2018			1,475	26,512		674,879	
35	June	2018			1,479	26,586		684,085	
36	July	2018			1,483	26,660		693,290	
37	August	2018			1,487	26,733		702,495	
38	September	2018			1,491	26,807		711,701	
39	October	2018			1,495	26,881		720,906	
40	November	2018			1,499	26,955		730,111	
41	December	2018			1,503	27,029		739,317	
42	13-month Average			-	1,479	26,586	-	684,085	-

Notes:

[A] Taken to Attachment H-4A, page 2, lines 7-11, Col. 3

[B] Reference for December balances as would be reported in FERC Form 1.

[C] Balance excludes reserve for depreciation of asset retirement costs

Period I

Statement BK
Attachment H-4A, Attachment 5
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For the 12 months ended 12/31/2018

			[1]	[2]	[3]	[4]	[5]	[6]
			ADIT Transmission Total (including Plant & Labor Related Transmission ADITs and applicable transmission adjustments from notes below					
			Acct. No. 281 (enter negative)	**Acct. No. 282** (enter negative) [B]	**Acct. No. 283** (enter negative) [C]	**Acct. No. 190** [D]	**Acct. No. 255** (enter negative) [E]	**Total**
1	December 31	2018	-	(382,163,846)	(7,424,432)	40,797,698	-	(348,790,580)

			ADIT Total Transmission-related only, including Plant & Labor Related Transmission ADITs (prior to adjusments from notes below)					
			Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
2	December 31	2018 [G]	-	264,595,322	(28,899,674)	45,273,196	1,786,148	282,754,992

Notes:

[A] Beginning/Ending Average with adjustments for FAS143, FAS106, FAS109, CIACs and normalization to populate Appendix H-4A, page 2, lines 19-23, col. 3 for accounts 281, 282, 283, 190, and 255, respectively

[B] FERC Account No. 282 is adjusted for the following items.

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
3	2018	-	669,170	(122,503,385)		4,265,691

[C] FERC Account No. 283 is adjusted for the following items.

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
4	2018	11,016	-	(35,369,567)		(965,555)

[D] FERC Account No. 190 is adjusted for the following items:

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
5	2018	-	-	(7,440,425)	11,320,438	595,486

[E] See Attachment H-4A, page 5, note K; A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f).

[F] Sourced from Attachment 5b, page 1, col. O for PTRR & Attachment 5C, page 2, col. O for ATRR

[G] Sourced from Attachment 5a, page 1, lines 1-5, col. 4

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Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line	1	2	3	4
		Transmission Ending	End Plant & Labor Related Allocated to Transmission	Total Transmission Ending (col. 2 + col. 3)
		(Note F)	(page 1, Col. K)	(Note E)
1	**ADIT- 282 From Account Subtotal Below**	264,595,322	-	264,595,321.75
2	**ADIT-283 From Account Subtotal Below**	(28,899,674)	-	(28,899,673.72)
3	**ADIT-190 From Account Subtotal Below**	45,273,196	-	45,273,196.36
4	**ADIT-281 From Account Subtotal Below**	-	-	-
5	**ADIT-255 From Account Subtotal Below**	1,786,148	-	1,786,148.00
	Total (sum rows 1-5)	282,754,992	-	282,754,992

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line		A	B	C	D	E	F
		End Plant Related	End Labor Related	Plant & Labor Subtotal	Gross Plant Allocator	Wages & Salary Allocator	End Plant & Labor Related ADIT
		(Note A)	(Note B)	Col. A + Col. B	(Note C)	(Note D)	(Col. A * Col. D) + (Col. B * Col. E)
1	ADIT- 282 From Account Total Below	-	-	-	23.55%	8.60%	-
2	ADIT-283 From Account Total Below	-	-	-	23.55%	8.60%	-
3	ADIT-190 From Account Total Below	-	-	-	23.55%	8.60%	-
4	ADIT-281 From Account Total Below	-	-	-	23.55%	8.60%	-
5	ADIT-255 From Account Total Below	-	-	-	23.55%	8.60%	-
6	**Subtotal**	-	-	-			-

Notes
A From column F (beginning on page 2)
B From column G (beginning on page 2)
C Refers to Attachment H-4A, page 2, line 6, col. 4
D Refers to Attachment H-4A, page 4, line 16, col.6
E Total Transmission Ending taken to Attachment 5, line 2
F From column E (beginning on page 2) by account

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Jersey Central Power & Light

A	B	C	D	E	F	G	
ADIT-190	End of Year Balance p234.18.c	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Asset Impairment	5,494,917			5,494,917			
Capitalized Interest	9,549,342			9,549,342			
Contribution in Aid of Construction	11,320,438			11,320,438			
Investment Tax Credit	698,409			698,409			
FAS109 Related to Property	(7,440,425)			(7,440,425)			
Federal NOL	19,161,238			19,161,238			
NJ State NOL	6,323,268			6,323,268			
AMT Credit Carryforward	119,554			119,554			
General Business Credit Carryforward	46,455			46,455			
				-			
Subtotal	45,273,196	-	-	45,273,196	-	-	

Instructions for Account 190:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

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Statement BK
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For the 12 months ended 12/31/2018

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT- 282	End of Year Balance p275.9.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
263A Capitalized Overheads	68,703,109			68,703,109			
Accelarated Depreciation	259,659,102			259,659,102			
AFUDC	6,972,494			6,972,494			
AFUDC Equity (FAS109)	3,205,580			3,205,580			
Asset Impairment	-			-			
Capitalized Interest	-			-			
Capitalized Tree Trimming	8,276,371			8,276,371			
Casualty Loss	7,234,904			7,234,904			
Contribution in Aid of Construction	-			-			
OPEBs	669,170			669,170			
Other	1,038,391			1,038,391			
Pension and Capitalized Benefits	13,938,960			13,938,960			
Tax Repairs	20,610,473			20,610,473			
Sale of Property - Book/Tax Gain/Loss	(4,268)			(4,268)			
FAS109 Related to Property	(125,708,964)			(125,708,964)			
Subtotal	264,595,322	-	-	264,595,322	-	-	

Instructions for Account 282:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

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Statement BK
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For the 12 months ended 12/31/2018

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-283	End of Year Balance p277.19.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
AFUDC Equity Flow Thru (Gross up)	1,253,427			1,253,427			
Property FAS109	(46,244,660)			(46,244,660)			
Accrued Taxes	(36,946)			(36,946)			
Accum. Prov. For Injuries and Damages	(116,857)			(116,857)			
Asset Retirement Obligation	11,016			11,016			
Company Debt - Issuance Discount	(30,961)			(30,961)			
Deferred Charge - EIB	40,414			40,414			
FAS 112 - Medical Benefit Accrual	(360,713)			(360,713)			
FAS 158 Pension & OPEB	(81,517)			(81,517)			
FE Service Timing Allocation	5,073,407			5,073,407			
Fed Rate Change - Non Property Gross-up (FAS 109)	3,762,207			3,762,207			
GR&F Tax Audit	(81,081)			(81,081)			
Pension Expense	(6,675,720)			(6,675,720)			
PJM Payable / Receivable	12,606			12,606			
PJM Unbilled Deferral	(1,477,850)			(1,477,850)			
Post Retirement Benefits FAS 106	(3,300,485)			(3,300,485)			
State Income Tax Deductible	1,020,111			1,020,111			
Storm Damage	18,726,481			18,726,481			
Unamortized Gain/Loss on Reacquired Debt	339,811			339,811			
Vacation Accrual	(199,527)			(199,527)			
Vegetation Management	(532,836)			(532,836)			
Subtotal	(28,899,674)		-	(28,899,674)	-	-	

Instructions for Account 283:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.

6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Period I

Statement BK
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Jersey Central Power & Light

A	B	C	D	E	F	G	
ADIT-281	End of Year Balance p273.8.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
				-			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
Subtotal			-	-	-	-	

Instructions for Account 281:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

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Jersey Central Power & Light

A	B	C	D	E	F	G	
ADIT-255	End of Year Balance p267.h	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Investment Tax Credit	1,786,148			1,786,148			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
Subtotal	1,786,148		-	1,786,148	-	-	

Instructions for Account 255:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Period I

Statement BK
Attachment H-4A, Attachment 5b
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For the 12 months ended 12/31/2018

Line		A	B	C	D	E	F	G	H	I
			2018 Quarterly Activity and Balances							
		Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
1	PTRR	0	0	0	0	0	0	0	0	0
		Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
2	PTRR	**0**	**0**		**0**		**0**		**0**	
		Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
3	PTRR	0	0	0	0	0	0	0	0	0
		Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
4	PTRR	**0**	**0**		**0**		**0**		**0**	
		Beginning 283 Including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
5	PTRR	0	0	0	0	0	0	0	0	0
		Beginning 283 Including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
6	PTRR	**0**	**0**		**0**		**0**		**0**	

					2018 PTRR				
			J	K	L	M	N	O	P
				Page 1, B+D+F+H	Page 1, row 2,4,6 Column A+B+D+F+H	J-L		M-N	Line 7= J-N-O Lines 8-9= -J+N+O
Line		Account	Estimated Ending Balance (Before Adjustments)	Projected Activity	Prorated Ending Balance	Prorated - Estimated End (Before Adjustments)	Sum of end ADIT Adjustments	Normalization	Ending ADIT Balance Included in Formula Rate
7	PTRR	Total Account 190	-	0	0	-	-	-	-
8	PTRR	Total Account 282	-	0	0	-	-	-	-
9	PTRR	Total Account 283	-	0	0	-	-	-	-
10	PTRR	Total ADIT Subject to Normalization	-	-	-	-	-	-	-

Notes:
1. Attachment 5b will only be populated within the PTRR

Period I

Statement BK
Attachment H-4A, Attachment 5c
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For the 12 months ended 12/31/2018

Line		A	B	C	D	E	F	G	H	I
			2018 Quarterly Activity and Balances							
		Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
1	PTRR	10,802,978	(30,558)	10,772,421	917,778	11,690,199	61,588	11,751,787	104,725	11,856,512
2	ATRR	34,544,371	1,872,667	36,417,038	1,872,667	38,289,705	1,872,667	40,162,373	1,872,667	42,035,040
		Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
3	PTRR	**10,802,978**	**(23,107)**		**465,175**		**15,692**		**287**	
4	ATRR	**34,544,371**	**1,416,044**		**949,160**		**477,145**		**5,131**	
		Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
5	PTRR	366,581,315	(218,896)	366,362,419	6,574,397	372,936,816	441,179	373,377,995	750,184	374,128,179
6	ATRR	375,028,763	2,813,331	377,842,094	2,813,331	380,655,425	2,813,331	383,468,756	2,813,331	386,282,087
		Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
7	PTRR	**366,581,315**	**(165,521)**		**3,332,229**		**112,410**		**2,055**	
8	ATRR	**375,028,763**	**2,127,341**		**1,425,935**		**716,821**		**7,708**	
		Beginning 283 Including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
9	PTRR	9,353,594	49,548	9,403,142	(1,488,139)	7,915,002	(99,862)	7,815,140	(169,807)	7,645,333
10	ATRR	(7,987,318)	3,613,394	(4,373,924)	3,613,394	(760,530)	3,613,394	2,852,864	3,613,394	6,466,258
		Beginning 283 Including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
11	PTRR	**9,353,594**	**37,466**		**(754,262)**		**(25,444)**		**(465)**	
12	ATRR	**(7,987,318)**	**2,732,320**		**1,831,446**		**920,673**		**9,900**	

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Statement BK
Attachment H-4A, Attachment 5c
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For the 12 months ended 12/31/2018

2018 PTRR

Line		Account	A	B	C	D	E	F	G
				Page 1, B+D+F+H	Page 1, row 3,7,11 Column A+B+D+F+H	A-C		D-E	Line 1= A-E-F Lines 2-3= -A+E+F
			Estimated Ending Balance (Before Adjustments)	Projected Activity	Prorated Ending Balance	Prorated - Estimated End (Before Adjustments)	Sum of end ADIT Adjustments	Normalization	Ending ADIT Balance Included in Formula Rate
1	PTRR	Total Account 190	23,164,549	1,053,534	11,261,026	11,903,523	11,308,037	**595,486**	**11,261,026**
2	PTRR	Total Account 282	379,622,892	7,546,864	369,862,488	9,760,404	5,494,713	**4,265,691**	**(369,862,488)**
3	PTRR	Total Account 283	11,524,999	(1,708,261)	8,610,888	2,914,111	3,879,666	**(965,555)**	**(8,610,888)**
4	PTRR	Total ADIT Subject to Normalization	(367,983,342)	(4,785,069)	(367,212,349)	(770,992)	20,682,416	3,895,622	(367,212,349)

2018 ATRR

Line		Account	H	I	J	K	L	M	N	O	P
				Page 1, B+D+F+H	Page 1, row 4,8,12 column A+B+D+F+H	H-J	D-K		E-M	K+L-M-N	Line 5= H-M-O Lines 6-7= -H+M+O
			Actual Ending Balance (Before Adjustments)	Actual Activity	Prorated Ending Balance	Prorated - Actual End (Before Adjustments)	Prorated Activity Not Projected	Sum of end ADIT Adjustments	ADIT Adjustments not projected	Normalization	Ending ADIT Balance Included in Formula Rate
5	ATRR	Total Account 190	45,273,196	7,490,669	37,391,851	7,881,345	4,022,178	3,880,013	7,428,024	**595,486**	**40,797,698**
6	ATRR	Total Account 282	264,595,322	11,253,323	379,306,568	(114,711,246)	124,471,650	(121,834,215)	127,328,928	**4,265,691**	**(382,163,846)**
7	ATRR	Total Account 283	(28,899,674)	14,453,576	(2,492,979)	(26,406,695)	29,320,806	(35,358,551)	39,238,217	**(965,555)**	**(7,424,432)**
8	ATRR	Total ADIT Subject to Normalization	(190,422,452)	(18,216,231)	(339,421,737)	148,999,285	157,814,633	(153,312,753)	173,995,169	3,895,622	(348,790,580)

Notes:
1. Attachment 5c will only be populated within the ATRR

Period I

Statement BK
Attachment H-4A, Attachment 6
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For the 12 months ended 12/31/2018

1	**Calculation of PBOP Expenses**		
2	**JCP&L**	**Amount**	**Source**
3	Total FirstEnergy PBOP expenses	-$155,537,000	FirstEnergy 2018 Actuarial Study
4	Labor dollars (First Energy)	$2,363,633,077	FirstEnergy 2018 Actual: Company Records
5	cost per labor dollar (line 3 / line 4)	-$0.0658	
6	labor (labor not capitalized) current year, transmission only	7,489,291	JCP&L Labor: Company Records
7	PBOP Expense for current year (line 5 * line 6)	-$492,827	
8	PBOP expense in Account 926 for current year, total company	(43,748,932)	JCP&L Account 926: Company Records
9	W&S Labor Allocator	8.597%	
10	Allocated Transmission PBOP (line 8 * line 9)	-$3,761,268	
11	PBOP Adjustment for Attachment H-4A, page 3, line 9 (line 7 - line 10)	$3,268,441	

12 Lines 3-4 cannot change absent a Section 205 or 206 filing approved or accepted by FERC in a separate proceeding

Period I

Statement BK
Attachment H-4A, Attachment 7
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For the 12 months ended 12/31/2018

Taxes Other than Income Calculation

			[A]	Dec 31, 2018
1	**Payroll Taxes**			
1a	FICA & unemployement taxes		263.i	5,793,391
1b			263.i	
1c			263.i	
1d			263.i	
1z		**Payroll Taxes Total**		5,793,391
2	**Highway and Vehicle Taxes**			
2a	Federal Excise Tax		263.i	2,595
2z		**Highway and Vehicle Taxes**		2,595
3	**Property Taxes**			
3a	New Jersey Property Tax		263.i	5,876,890
3b	PA PURTA Tax		263.i	-
3c	NJ State S&U		263.i	75,432
3d			263.i	-
3z		**Property Taxes**		5,952,322
4	**Gross Receipts Tax**			
4a	Gross Receipts Tax		263.i	-
4z		**Gross Receipts Tax**		-
5	**Other Taxes**			
5a	Sales & Use Tax		263.i	
5b			263.i	
5c			263.i	
5d				-
5z		**Other Taxes**		-
6z	**Payments in lieu of taxes**			
7	Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z) [tie to 114.14c]			$11,748,308.00

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Period I

Statement BK
Attachment H-4A, Attachment 8
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For the 12 months ended 12/31/2018

Capital Structure Calculation

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Proprietary Capital	**Preferred Stock**	**Account 216.1**	**Account 219**	**Goodwill**	**Common Stock**	**Long Term Debt**
			[A]	112.16.c	112.3.c	112.12.c	112.15.c	233.5.f	(1) - (2) - (3) - (4) - (5)	112.24.c
1	December	2017		3,188,770,439	-	(36,428)	(2,044,696)	1,810,936,125	1,379,915,438	1,694,643,695
2	January	2018		3,202,185,251		(36,428)	(2,068,458)	1,810,936,125	1,393,354,012	1,694,693,522
3	February	2018		3,212,931,128		(36,428)	(1,881,840)	1,810,936,125	1,403,913,271	1,694,743,349
4	March	2018		3,220,117,449		(36,743)	(1,891,881)	1,810,936,125	1,411,109,948	1,694,793,176
5	April	2018		3,224,318,595		(36,743)	(1,908,858)	1,810,936,125	1,415,328,071	1,694,843,002
6	May	2018		3,236,837,064		(36,743)	(1,925,870)	1,810,936,125	1,427,863,552	1,694,892,829
7	June	2018		3,407,809,455		(37,169)	(1,959,401)	1,810,936,125	1,598,869,900	1,544,939,319
8	July	2018		3,439,620,566		(37,169)	(1,992,933)	1,810,936,125	1,630,714,543	1,544,982,888
9	August	2018		3,469,915,064		(37,169)	(2,026,465)	1,810,936,125	1,661,042,573	1,545,026,458
10	September	2018		3,493,800,228		(37,689)	(2,059,996)	1,810,936,125	1,684,961,788	1,545,070,027
11	October	2018		3,501,339,986		(37,689)	(2,093,528)	1,810,936,125	1,692,535,078	1,545,113,596
12	November	2018		3,510,996,567		(37,689)	(2,127,060)	1,810,936,125	1,702,225,191	1,545,157,166
13	December	2018		3,513,620,286		(38,436)	(5,575,366)	1,810,936,125	1,708,297,963	1,545,200,735
14	13-month Average			3,355,558,621	-	(37,117)	(2,273,566)	1,810,936,125	1,546,933,179	1,614,161,520

Notes:
[A] Reference for December balances as would be reported in FERC Form 1.

Period I

Statement BK
Attachment H-4A, Attachment 9
page 1 of 1

Stated Value Inputs

For the 12 months ended 12/31/2018

Formula Rate Protocols
Section VIII.A

1. Rate of Return on Common Equity ("ROE")

JCP&L's stated ROE is set to: 10.8%

2. Postretirement Benefits Other Than Pension ("PBOP")

**sometimes referred to as Other Post Employment Benefits, or "OPEB"*

Total FirstEnergy PBOP expenses	-$155,537,000
Labor dollars (FirstEnergy)	$2,363,633,077
cost per labor dollar	$-0.0658

3. Depreciation Rates (1)

FERC Account	Depr %
350.2	1.53%
352	1.14%
353	2.43%
354	0.83%
355	1.95%
356	2.45%
356.1	1.09%
357	1.39%
358	1.88%
359	1.10%
389.2	3.92%
390.1	1.51%
390.2	0.46%
391.1	4.00%
391.15	5.00%
391.2	20.00%
391.25	20.00%
392	3.84%
393	3.33%
394	4.00%
395	5.00%
396	3.03%
397	5.00%
398	5.00%

Note: (1) Account 303 amortization period is 7 years.
(2) Accounts 391.10, 391.15, 391.20, 391.25, 393, 394, 395, 397, and 398 have an unrecovered reserve to be amortized over 5 years separately from the assets in these accounts beginning January 1, 2020 through December 31, 2025.

Period I

Statement BK
Attachment H-4A, Attachment 10
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For the 12 months ended 12/31/2018

Debt Cost Calculation

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED 12/31/2018

Long Term Debt 12/31/2018 (t=N)	(a) Issue Date	(b) Maturity Date	(c) ORIGINAL ISSUANCE (table 2, col. cc)	(d) Net Proceeds At Issuance (table 2, col. hh)	(e) Net Amount Outstanding at t=N	(f) Months Outstanding at t=N	(g) Average Net Outstanding in Year* z* ((col e. * col. F)/12)	(h) Weighted Outstanding Ratios (col. g/col. g total)	(i) Effective Cost Rate (Table 2, Col. ll)	(j) Weighted Debt Cost at t = N (h) * (i)
First Mortgage Bonds:										
(1) 4.80% Series	5/19/2003	6/15/2018	$ 150,000,000	$ 147,492,184	$ 150,000,000	5.5	$ 68,750,000.00	4.27%	4.96%	0.21%
(2) 6.40% Series	5/12/2006	5/15/2036	$ 200,000,000	$ 196,437,127	$ 197,936,503	12	$ 197,936,502.72	12.30%	6.54%	0.80%
(3) 6.15% Series	5/16/2007	6/1/2037	$ 300,000,000	$ 295,979,779	$ 297,535,454	12	$ 297,535,453.98	18.49%	6.25%	1.16%
(4) 7.35% Series	1/27/2009	2/1/2019	$ 300,000,000	$ 297,350,139	$ 299,977,918	12	$ 299,977,917.83	18.65%	7.48%	1.39%
(5) 4.70% Series	8/21/2013	4/1/2024	$ 500,000,000	$ 493,197,650	$ 496,618,563	12	$ 496,618,563.15	30.87%	4.87%	1.50%
(6) 4.30% Series	8/18/2015	1/15/2026	$ 250,000,000	$ 247,086,512	$ 248,030,482	12	$ 248,030,481.83	15.42%	4.44%	0.68%
			$ 1,700,000,000		$ 1,690,098,920		$ 1,608,848,920	100.000%		5.75% **

t = time
The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.
The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.
* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).
Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).
** This Total Weighted Average Debt Cost will be shown on page 4, line 22, column 5 of formula rate Attachment H-4A.

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED 12/31/2018

Long Term Debt Affiliate	(aa) Issue Date	(bb) Maturity Date	(cc) Amount Issued	(dd) (Discount) Premium at Issuance	(ee) Issuance Expense	(ff) Loss/Gain on Reacquired Debt	(gg) Less Related ADIT	(hh) Net Proceeds (col. cc + col. dd - col. ee - col. ff)	(ii) Net Proceeds Ratio ((col. hh / col. cc)*100)	(jj) Coupon Rate	(kk) Annual Interest (col. cc * col. jj)	(ll) Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
First Mortgage Bonds:												
(1) 4.80% Series	5/19/2003	6/15/2018	$ 150,000,000	$ (1,149,000)	$ 1,358,816			$ 147,492,184	98.3281	0.0480	$ 7,200,000	4.96%
(2) 6.40% Series	5/12/2006	5/15/2036	$ 200,000,000	$ (1,216,000)	$ 2,346,873			$ 196,437,127	98.2186	0.0640	$ 12,800,000	6.54%
(3) 6.15% Series	5/16/2007	6/1/2037	$ 300,000,000	$ (3,693,000)	$ 327,221			$ 295,979,779	98.6599	0.0615	$ 18,450,000	6.25%
(4) 7.35% Series	1/27/2009	2/1/2019	$ 300,000,000	$ (381,000)	$ 2,268,861			$ 297,350,139	99.1167	0.0735	$ 22,050,000	7.48%
(5) 4.70% Series	8/21/2013	4/1/2024	$ 500,000,000	$ (2,595,000)	$ 4,207,350			$ 493,197,650	98.6395	0.0470	$ 23,500,000	4.87%
(6) 4.30% Series	8/18/2015	1/15/2026	$ 250,000,000	$ (800,000)	$ 2,113,488			$ 247,086,512	98.8346	0.0430	$ 10,750,000	4.44%
TOTALS			$ 1,700,000,000	(9,834,000)	$ 12,622,609	-	xxx	$ 1,677,543,391			$ 94,750,000	

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation
Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_o equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

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Statement BK
Attachment H-4A, Attachment 11
page 1 of 2
For the 12 months ended 12/31/2018

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-4A

Line No.	(1)	(2) Reference	(3) Transmission	(4) Allocator
1	Gross Transmission Plant - Total	Attach. H-4A, p. 2, line 2, col. 5 (Note A)	$ 1,534,245,644	
2	Net Transmission Plant - Total	Attach. H-4A, p. 2, line 14, col. 5 (Note B)	$ 1,144,482,666	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-4A, p. 3, line 14, col. 5	$ 33,648,037	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)	2.193132%	2.193132%
	GENERAL, INTANGIBLE, AND COMMON (G,I, & C) DEPRECIATION EXPENSE			
5	Total G, I, & C depreciation expense	Attach. H-4A, p. 3, lines 16 & 17, col. 5	$ 1,618,125	
6	Annual allocation factor for G, I, & C depreciation expense	(line 5 divided by line 1, col. 3)	0.105467%	0.105467%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach. H-4A, p. 3, line 27, col. 5	$ 1,900,268	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col. 3)	0.123857%	0.123857%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, & 8**		**2.422456%**
	INCOME TAXES			
10	Total Income Taxes	Attach. H-4A, p. 3, line 38, col. 5	$ 12,564,190	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2, col. 3)	1.097805%	1.097805%
	RETURN			
12	Return on Rate Base	Attach. H-4A, p. 3, line 39, col. 5	$ 66,815,696	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2, col. 3)	5.838070%	5.838070%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**6.935875%**

Columns 5-9 (page 1) only applies with incentive ROE project(s) (Note F)

(5) Line No.	(6)	(7) Reference	(8) Transmission	(9) Allocator
	INCOME TAXES			
10b	Total Income Taxes	Attachment 2, line 33	$ 12,564,190	
11b	Annual Allocation Factor for Income Taxes	(line 10b divided by line 2, col. 3)	1.097805%	1.097805%
	RETURN			
12b	Return on Rate Base	Attachment 2, line 22	$ 66,815,696	
13b	Annual Allocation Factor for Return on Rate Base	(line 12b divided by line 2, col. 3)	5.838070%	5.838070%
14b	**Annual Allocation Factor for Return**	**Sum of line 11b and 13b**		**6.935875%**
15	**Additional Annual Allocation Factor for Return**	**Line 14 b, col. 9 less line 14, col. 4**		**0.00000%**

Period I

Statement BK
Attachment H-4A, Attachment 11
page 2 of 2
For the 12 months ended 12/31/2018

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-4A

Line No.	(1) Project Name	(2) RTEP Project Number	(3) Project Gross Plant	(4) Annual Allocation Factor for Expense	(5) Annual Expense Charge	(6) Project Net Plant	(7) Annual Allocation Factor for Return	(8) Annual Return Charge	(9) Project Depreciation Expense	(10) Annual Revenue Requirement	(11) Additional Incentive Annual Allocation Factor for Return (Note F)	(12) Total Annual Revenue Requirement	(13) True-up Adjustment	(14) Net Revenue Requirement with True-up
1			(Note C & H)	(Page 1, line 9)	(Col. 3 * Col. 4)	(Note D & H)	Page 1, line 14	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8, & 9)	(Col. 6 * Page 1, line 15, Col. 9)	(Sum Col. 10 & 11)	(Note G)	(Sum Col. 12 & 13)
2a	Upgrade the Portland – Greystone 230kV circuit	b0174	$ 12,588,193	2.422456%	$304,943	$ 10,248,463	6.935875%	$710,821	$ 353,204	$1,368,968	0	$1,368,968		$1,368,968
2b	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	b0268	$ 5,983,501	2.422456%	$144,948	$ 5,197,844	6.935875%	$360,516	$ 168,535	$673,999	0	$673,999		$673,999
2c	Add a 2nd Raritan River 230/115 kV transformer	b0726	$ 7,323,996	2.422456%	$177,421	$ 6,802,364	6.935875%	$471,803	$ 175,348	$824,572	0	$824,572		$824,572
2d	Build a new 230 kV circuit from Larrabee to Oceanview	b2015	$ 165,478,023	2.422456%	$4,008,633	$ 162,091,504	6.935875%	$11,242,464	$3,992,903	$19,244,000	0	$19,244,000		$19,244,000
3	Transmission Enhancement Credit taken to Attachment H-4A Page 1, Line 7											22,111,539.12		
4	Additional Incentive Revenue taken to Attachment H-4A, Page 3, Line 41										$0.00			

Notes
A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-4A.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-4A.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 above. This value includes subsequent capital investments required to maintain the project in-service.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-4A, page 3, line 15.
F Any actual ROE incentive must be approved by the Commission
G True-up adjustment is calculated on the project true-up schedule, attachment 12 column j
H Based on a 13-month average

Period I

Statement BK
Attachment H-4A, Attachment 11a
page 1 of 2
For the 12 months ended 12/31/2018

TEC Worksheet Support
Net Plant Detail

Line No.	Project Name	RTEP Project Number	Project Gross Plant	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
			(Note A)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)
2a	Upgrade the Portland – Greystone 230kV circuit	b0174	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193
2b	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	b0268	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501
2c	Add a 2nd Raritan River 230/115 kV transformer	b0726	$ 7,323,996	$ 7,323,914	$ 7,323,914	$ 7,323,914	$ 7,323,914	$ 7,323,914	$ 7,323,914	$ 7,324,581	$ 7,323,914	$ 7,323,914	$ 7,323,914	$ 7,323,914	$ 7,323,914	$ 7,324,313
2d	Build a new 230 kV circuit from Larrabee to Oceanview	b2015	$ 165,478,023	$138,386,894	$138,408,764	$166,300,949	$166,580,490	$166,598,123	$172,509,405	$171,801,407	$172,145,557	$171,693,390	$171,683,434	$171,681,272	$171,728,625	$171,695,986

NOTE

[A] Project Gross Plant is the total capital investment for the project, including subsequent capital investments required to maintain the project in-service. Utilizing a 13-month average.

[D] Company records

Period I

Statement BK
Attachment H-4A, Attachment 11a
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For the 12 months ended 12/31/2018

TEC Worksheet Support
Net Plant Detail

Accumulated Depreciation	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	[redacted]	Project Net Plant
(Note B)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)		(Note B & C)
$2,339,730.20	$ 2,176,713	$ 2,203,883	$ 2,231,052	$ 2,258,222	$ 2,285,391	$ 2,312,561	$ 2,339,730	$ 2,366,900	$ 2,394,069	$ 2,421,239	$ 2,448,408	$ 2,475,578	$ 2,502,747		$10,248,463
$785,657.16	$ 707,872	$ 720,836	$ 733,800	$ 746,764	$ 759,729	$ 772,693	$ 785,657	$ 798,621	$ 811,586	$ 824,550	$ 837,514	$ 850,478	$ 863,443		$5,197,844
$521,632.19	$ 440,702	$ 454,191	$ 467,679	$ 481,167	$ 494,655	$ 508,143	$ 521,632	$ 535,121	$ 548,609	$ 562,097	$ 575,586	$ 589,074	$ 602,562		$6,802,364
$3,386,518.67	$1,591,564	$1,846,447	$2,127,034	$2,433,562	$2,740,364	$3,052,625	$3,369,678	$3,686,396	$4,003,015	$4,319,207	$4,635,389	$4,951,612	$5,267,849		$162,091,504

NOTE

[B] Utilizing a 13-month average.
[C] Taken to Attachment 11, Page 2, Col. 6
[D] Company records

Period I

Statement BK
Attachment H-4A, Attachment 12
page 1 of 1
For the 12 months ended 12/31/2018

TEC - True-up
To be completed after Attachment 11 for the True-up Year is updated using actual data

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.		Project Name	RTEP Project Number	Actual Revenues for Attachment 11	Projected Annual Revenue Requirement	% of Total Revenue Requirement	Revenue Received	Actual Annual Revenue Requirement	True-up Adjustment Principal Over/(Under)	Applicable Interest Rate on Over/(Under)	Total True-up Adjustment with Interest Over(Under)
					Projected Attachment 11 p 2 of 2, col. 14	Col d, line 2 / Col. d, line 3	Col c, line 1 * Col e	Actual Attachment 11 p 2 of 2, col. 14	Col. f - Col. G	Col. H line 2x / Col. H line 3 * Col. J line 4	Col. h + Col. i
1	[A]	Actual RTEP Credit Revenues for true-up year		0							
2a		Project 1			-	-	-	-	-	#DIV/0!	#DIV/0!
2b		Project 2				-	-		-	#DIV/0!	#DIV/0!
2c		Project 3				-	-		-	#DIV/0!	#DIV/0!
3		Subtotal			-			-	-		#DIV/0!
4		Total Interest (Sourced from Attachment 13a, line 30)									-

NOTE
[A] Amount included in revenues reported on pages 328-330 of FERC Form 1.

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Statement BK
Attachment H-4A, Attachment 13
page 1 of 1
For the 12 months ended 12/31/2018

Net Revenue Requirement True-up with Interest

	Reconciliation Revenue Requirement For Year 2016 Available June 10, 2017		2016 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2015		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.0000%				
	An over or under collection will be recovered prorata over 2015, held for 2016 and returned prorate over 2017							
	Calculation of Interest					**Monthly**		
3	January	Year 2015	-	0.0000%	12	-		-
4	February	Year 2015	-	0.0000%	11	-		-
5	March	Year 2015	-	0.0000%	10	-		-
6	April	Year 2015	-	0.0000%	9	-		-
7	May	Year 2015	-	0.0000%	8	-		-
8	June	Year 2015	-	0.0000%	7	-		-
9	July	Year 2015	-	0.0000%	6	-		-
10	August	Year 2015	-	0.0000%	5	-		-
11	September	Year 2015	-	0.0000%	4	-		-
12	October	Year 2015	-	0.0000%	3	-		-
13	November	Year 2015	-	0.0000%	2	-		-
14	December	Year 2015	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 2016	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
16	January	Year 2017	-	0.0000%		-	-	-
17	February	Year 2017	-	0.0000%		-	-	-
18	March	Year 2017	-	0.0000%		-	-	-
19	April	Year 2017	-	0.0000%		-	-	-
20	May	Year 2017	-	0.0000%		-	-	-
21	June	Year 2017	-	0.0000%		-	-	-
22	July	Year 2017	-	0.0000%		-	-	-
23	August	Year 2017	-	0.0000%		-	-	-
24	September	Year 2017	-	0.0000%		-	-	-
25	October	Year 2017	-	0.0000%		-	-	-
26	November	Year 2017	-	0.0000%		-	-	-
27	December	Year 2017	-	0.0000%		-	-	-
						-		
28	True-Up with Interest						$ -	
29	Less Over (Under) Recovery						$ -	
30	Total Interest						$ -	

[A] Interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if JCP&L does not have short term debt

Period I

Statement BK
Attachment H-4A, Attachment 13a
page 1 of 1
For the 12 months ended 12/31/2018

TEC Revenue Requirement True-up with Interest

	TEC Reconciliation Revenue Requirement For Year 2015 Available June 10, 2016		TEC 2015 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2014		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.0000%				
	An over or under collection will be recovered prorata over 2015, held for 2016 and returned prorate over 2017							
	Calculation of Interest					**Monthly**		
3	January	Year 2015	-	0.0000%	12	-		-
4	February	Year 2015	-	0.0000%	11	-		-
5	March	Year 2015	-	0.0000%	10	-		-
6	April	Year 2015	-	0.0000%	9	-		-
7	May	Year 2015	-	0.0000%	8	-		-
8	June	Year 2015	-	0.0000%	7	-		-
9	July	Year 2015	-	0.0000%	6	-		-
10	August	Year 2015	-	0.0000%	5	-		-
11	September	Year 2015	-	0.0000%	4	-		-
12	October	Year 2015	-	0.0000%	3	-		-
13	November	Year 2015	-	0.0000%	2	-		-
14	December	Year 2015	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 2016	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
16	January	Year 2017	-	0.0000%		-	-	-
17	February	Year 2017	-	0.0000%		-	-	-
18	March	Year 2017	-	0.0000%		-	-	-
19	April	Year 2017	-	0.0000%		-	-	-
20	May	Year 2017	-	0.0000%		-	-	-
21	June	Year 2017	-	0.0000%		-	-	-
22	July	Year 2017	-	0.0000%		-	-	-
23	August	Year 2017	-	0.0000%		-	-	-
24	September	Year 2017	-	0.0000%		-	-	-
25	October	Year 2017	-	0.0000%		-	-	-
26	November	Year 2017	-	0.0000%		-	-	-
27	December	Year 2017	-	0.0000%		-	-	-
						-		
28	True-Up with Interest						$ -	
29	Less Over (Under) Recovery						$ -	
30	Total Interest						$ -	

[A] Interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if JCP&L does not have short term debt

Period I

Statement BK
Attachment H-4A, Attachment 14
page 1 of 1

Other Rate Base Items

For the 12 months ended 12/31/2018

			[1]	[2]	[3]	[4]	[5]	[6]
			Land Held for Future Use	**Materials & Supplies**	**Prepayments (Account 165)**		**Total**	
		[A]	214.x.d	227.8.c & .16.c	111.57.c [B]			
1	December 31	2017	-	-	1,329,929		1,329,929	
2	December 31	2018	-	-	2,254,210		2,254,210	
3	Begin/End Average		-	-	1,792,070		1,792,070	

					Unfunded Reserve - Plant Related			**Total**
	FERC Acct No.		**228.1**	**228.2**	**228.3**	**228.4**	**242**	
		[A] [C]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c	
4	December 31	2017	-	-	-	-	-	-
5	December 31	2018	-	-	-	-	-	-
6	Begin/End Average		-	-	-	-	-	-

					Unfunded Reserve - Labor Related			**Total**
	FERC Acct No.		**228.1**	**228.2**	**228.3**	**228.4**	**242**	
		[A] [C]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c	
7	December 31	2017	-	-	-	-	-	-
8	December 31	2018	-	-	-	-	-	-
9	Begin/End Average		-	-	-	-	-	-

Notes:
[A] Reference for December balances as would be reported in FERC Form 1.
[B] Prepayments shall exclude prepayments of income taxes.
[C] Includes transmission-related balance only

Period I

Statement BK
Attachment H-4A, Attachment 15
page 1 of 1
For the 12 months ended 12/31/2018

Income Tax Adjustments

	[1]	[2]	[3]	
			Dec 31, 2018	Reference
1	Tax adjustment for Permanent Differences & AFUDC Equity	[A] [C]	240,356	JCP&L Company Records
2	Amortized Excess Deferred Taxes (enter negative)	[B] [C]	(3,248,929)	JCP&L Company Records
3	Amortized Deficient Deferred Taxes	[B] [C]	-	JCP&L Company Records

Notes:

[A] AFUDC equity component is the gross cumulative annual amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function.

[B] Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. The balance located within Column 3, row 2 and row 3, is the net impact of excess deferred and deficient amortization.

[C] Year end balance for line 1 taken to Attachment H-4A, page 3, line 32; Year end balance for lines 2-3 taken to Attachment H-4A, page 3, line 33

Period I

Statement BK
Attachment H-4A, Attachment 15a
page 1 of 1
For the 12 months ended 12/31/2018

Non-Property Book-Tax Timing Difference [b] [c]

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Line No.	Description	EDIT Transmission Allocation	Amortization Period	Years Remaining	Amortization of EDIT	Protected (P) Non-Protected (N)
1	Accrued Taxes: FICA on Vacation Accrual	8,680	10	9	868	N
2	Accrued Taxes: Tax Audit Reserves	6,238	10	9	624	N
3	Accum Prov For Inj and Damage-Gen Liability	15,386	10	9	1,539	N
4	Accum Prov For Inj and Damage-Workers Comp	50,817	10	9	5,082	N
5	Asset Retirement Obligation Liability	(1,647)	10	9	(165)	N
6	Company Debt - Issuance Discount	16,436	10	9	1,644	N
7	Deferred Charge-EIB	(15,677)	10	9	(1,568)	N
8	FAS 112 - Medical Benefit Accrual	165,849	10	9	16,585	N
9	FAS 158 OPEB OCI Offset	(22,157)	10	9	(2,216)	N
10	FAS 158 Pension OCI Offset	1,790	10	9	179	N
11	FE Service Tax Interest Allocation	(712)	10	9	(71)	N
12	FE Service Timing Allocation	(503,373)	10	9	(50,337)	N
13	Federal Long Term NOL	5,037,433	35	34	143,927	P
14	Federal Long Term NOL	6,981,827	10	9	698,183	N
15	GR&F Tax Audit	36,747	10	9	3,675	N
16	NOL Deferred Tax Asset - LT NJ	(106,781)	10	9	(10,678)	N
17	Pension/OPEB : Other Def Cr. or Dr.	2,289,854	10	9	228,985	N
18	Pensions Expense	2,716,133	10	9	271,613	N
19	PJM Receivable	(1,381,762)	10	9	(138,176)	N
20	Post Retirement Benefits SFAS 106 Accrual	3,107,222	10	9	310,722	N
21	Post Retirement Benefits SFAS 106 Payments	(1,090,624)	10	9	(109,062)	N
22	Sale of Property - Book Gain or (Loss)	89,727	10	9	8,973	N
23	Sale of Property - Tax Gain or (Loss)	(94,435)	10	9	(9,444)	N
24	State Income Tax Deductible	(680,043)	10	9	(68,004)	N
25	Storm Damage	(6,198,498)	10	9	(619,850)	N
26	Unamortized Gain on Reacquired Debt	1,606	10	9	161	N
27	Unamortized Loss on Reacquired Debt	(204,887)	10	9	(20,489)	N
28	Vacation Pay Accrual	95,018	10	9	9,502	N
29	Vegetation Management	(29,221)	10	9	(2,922)	N
30	**Total Non-Property Amortization (Total of lines 1 thru 29)**				**669,278**	
31	**Property Book-Tax Timing Difference [A] [C]**				**(3,918,207)**	N & P
32	**Total Non-Property & Property Amortization [A] [B] [C]**				**(3,248,929)**	N & P

Notes:

Above amortization is populated from company records

[A] Ties to Attachment 15, page 1, line 2, column 3 for net excess & Attachment 15, page 1, line 3, Column 3 for net deficient

[B] The amortization schedule of the EDIT balance related to Tax Cuts and Job Act of 2017 shall be consistent with the following periods:

Protected Property & Non-Protected Property	ARAM
Non-Protected, Non-Property:	10 years
Protected, Non-Property:	35 years

[C] The regulatory assets and liabilities, included in FERC accounts 182.3 and 254, respectively, will amortize through FERC income statement accounts 410.1 and 411.1

Period I

Statement BK
Attachment H-4A, Attachment 16
page 1 of 1
For the 12 months ended 12/31/2018

Abandoned Plant

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
2	December 2017	p111.71.d (and Notes)	13				-
3	January	FERC Account 182.2	12	-	-	-	-
4	February	FERC Account 182.2	11	-	-	-	-
5	March	FERC Account 182.2	10	-	-	-	-
6	April	FERC Account 182.2	9	-	-	-	-
7	May	FERC Account 182.2	8	-	-	-	-
8	June	FERC Account 182.2	7	-	-	-	-
9	July	FERC Account 182.2	6	-	-	-	-
10	August	FERC Account 182.2	5	-	-	-	-
11	September	FERC Account 182.2	4	-	-	-	-
12	October	FERC Account 182.2	3	-	-	-	-
13	November	FERC Account 182.2	2	-	-	-	-
14	December 2018	p230b	1	-	-	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$0.00		$0.00
					Attachment H-4A, page 3, Line 18		Attachment H-4A, page 2, Line 27

Note:

Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC and will be zero until the Commission accepts or approves recovery of the cost of abandoned plant

Period I

Statement BK
Attachment H-4A, Attachment 17
page 1 of 1
For the 12 months ended 12/31/2018

			CWIP [A] 216.b
1	December	2017	
2	January	2018	
3	February	2018	
4	March	2018	
5	April	2018	
6	May	2018	
7	June	2018	
8	July	2018	
9	August	2018	
10	September	2018	
11	October	2018	
12	November	2018	
13	December	2018	
14	13-month Average		-

Notes:
[A] Includes only CWIP authorized by the Commission for inclusion in rate base.

Period I

Statement BK
Attachment H-4A, Attachment 18
page 1 of 1
For the 12 months ended 12/31/2018

Federal Income Tax Rate

Nominal Federal Income Tax Rate (entered on Attachment H-4A, page 5 of 5, Note K)	21.00%

State Income Tax Rate

	New Jersey	Combined Rate (entered on Attachment H-4A, page 5 of 5, Note K)
Nominal State Income Tax Rate	9.00%	
Times Apportionment Percentage	100.00%	
Combined State Income Tax Rate	9.000%	9.000%

Period I

Statement BK
Attachment H-4A, Attachment 19
page 1 of 1
For the 12 months ended 12/31/2018

Regulatory Asset

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (Company Records)	Additions (Deductions)	Ending Balance
2	December 2017	p232 (and Notes)	13				-
3	January	FERC Account 182.3	12	-	-	-	-
4	February	FERC Account 182.3	11	-	-	-	-
5	March	FERC Account 182.3	10	-	-	-	-
6	April	FERC Account 182.3	9	-	-	-	-
7	May	FERC Account 182.3	8	-	-	-	-
8	June	FERC Account 182.3	7	-	-	-	-
9	July	FERC Account 182.3	6	-	-	-	-
10	August	FERC Account 182.3	5	-	-	-	-
11	September	FERC Account 182.3	4	-	-	-	-
12	October	FERC Account 182.3	3	-	-	-	-
13	November	FERC Account 182.3	2	-	-	-	-
14	December 2018	p232 (and Notes)	1	-	-	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$0.00	-	$0.00

Period I

Statement BK
Attachment H-4A, Attachment 20
page 1 of 2
For the 12 months ended 12/31/2018

Operation and Maintenance Expenses

FF1 Page 321 Line No.	**Account Reference**	**Description**	**Account Balance [A]**
82		***Operation***	
83	560	Operation Supervision and Engineering	$100,346
84			
85	561.1	Load Dispatch-Reliability	$1,359,422
86	561.2	Load Dispatch-Monitor and Operate Transmission System	$188,796
87	561.3	Load-Dispatch-Transmission Service and Scheduling	
88	561.4	Scheduling, System Control and Dispatch Services	$93,130
89	561.5	Reliability, Planning and Standards Development	$351,461
90	561.6	Transmission Service Studies	-$1,338
91	561.7	Generation Interconnection Studies	-$3,442
92	561.8	Reliability, Planning and Standards Development Services	$8,729
93	562	Station Expenses	$368,545
94	563	Overhead Lines Expense	$1,398,636
95	564	Underground Lines Expense	
96	565	Transmission of Electricity by Others	$235,050
97	566	Miscellaneous Transmission Expense	-$5,175,022
98	567	Rents	$10,466,721
99		TOTAL Operation (Enter Total of Lines 83 thru 98)	$9,391,034
100		***Maintenance***	
101	568	Maintenance Supervision and Engineering	$2,596,867
102	569	Maintenance of Structures	
103	569.1	Maintenance of Computer Hardware	$16,701
104	569.2	Maintenance of Computer Software	$107,855
105	569.3	Maintenance of Communication Equipment	$302,548
106	569.4	Maintenance of Miscellaneous Regional Transmission Plant	
107	570	Maintenance of Station Equipment	$6,075,886
108	571	Maintenance of Overhead Lines	$9,223,705
109	572	Maintenance of Underground Lines	$1,494
110	573	Maintenance of Miscellaneous Transmission Plant	$207,311
111		TOTAL Maintenance (Total of lines 101 thru 110)	$18,532,367
112		**TOTAL Transmission Expenses (Total of lines 99 and 111)**	**$27,923,401**

Notes:
[A] December balances as would be reported in FERC Form 1

Period I

Statement BK
Attachment H-4A, Attachment 20
page 2 of 2
For the 12 months ended 12/31/2018

Administrative and General (A&G) Expenses

FF1 Page 323 Line No.	**Account Reference**	**Description**	**Account Balance [B]**
180		***Operation***	
181	920	Administrative and General Salaries	$235,921
182	921	Office Supplies and Expenses	-$212,058
183	Less 922	Administrative Expenses Transferred - Credit	
184	923	Outside Services Employed	$5,749,977
185	924	Property Insurance	$21,887
186	925	Injuries and Damages	$342,432
187	926	Employee Pensions and Benefits	-$2,138,825
188	927	Franchise Requirements	
189	928	Regulatory Commission Expense	$262,375
190	Less 929	(Less) Duplicate Charges-Cr.	
191	930.1	General Advertising Expenses	$208,599
192	930.2	Miscellaneous General Expenses	$163,484
193	931	Rents	$10,664
194		**Total Operation (Enter Total of lines 181 thru 193)**	$4,644,455
195		***Maintenance***	
196	935	Maintenance of General Plant	$241,160
197		**TOTAL A&G Expenses (Total of lines 194 and 196)**	**$4,885,615**

Notes:
[B] December balances as would be reported in FERC Form 1, transmission only

JERSEY CENTRAL POWER & LIGHT COMPANY
REVENUE DATA TO REFLECT CHANGED RATES AND PRESENT RATES
TWELVE MONTHS ENDED 12/31/20

Line No.	2020 Revenue Reflecting Present Rate		2020 Revenue Reflecting Proposed Rate		Difference (Proposed minus Present)		Change
	Monthly	Annual (1)	Monthly	Annual (1)	Monthly	Annual	%
1	$ 13,135,587	$ 157,627,046	$ 14,129,824	$ 169,557,888	$ 994,237	$ 11,930,842	7.57%

Note:
(1) Refer to WP-01; Includes NITS and TEC

WP-01
BG BH Support

Line				Units
1	JCPL Zone		6,057.1	MW
2	Stated NITS Rate	$	22,287.9	Per MW Per Year
3	Stated NITS Revenue (1)	$	135,000,000	Dollars
4	JCPL Zone		6,057.1	MW
5	Proposed NITS Rate	$	24,354.61	Per MW Per Year
6	Proposed NITS Revenue	$	147,518,299	Dollars
7	Stated TEC Revenue (1)	$	22,627,046	Dollars
8	Proposed TEC Revenue	$	22,039,589	Dollars

Note:
(1) Uncontested settlement approved by FERC on February 20, 2018 under ER17-217 included a stated NITS revenue requirement of $135,000,000 and TEC revenue of $22,627,046.

Period II

Statement BK
Attachment H-4A
page 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

Jersey Central Power & Light

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 42, col 5]					$ 170,350,964
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 451	(page 4, line 29)	-	TP	0.99785	-
3	Account No. 454	(page 4, line 30)	81,960	TP	0.99785	81,784
4	Account No. 456	(page 4, line 31)	712,824	TP	0.99785	711,292
5	Revenues from Grandfathered Interzonal Transactions		-	TP	0.99785	-
6	Revenues from service provided by the ISO at a discount		-	TP	0.99785	-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	22,087,043	TP	0.99785	22,039,589
8	TOTAL REVENUE CREDITS (sum lines 2-7)		22,881,826			22,832,665
9	True-up Adjustment with Interest	(Attachment 13, Line 28) enter negative				-
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)				$ 147,518,299
	DIVISOR					Total
11	1 Coincident Peak (CP) (MW)			(Note A)		6,057.1
12	Average 12 CPs (MW)			(Note CC)		4,053.2
			Total			
13	Annual Rate ($/MW/Yr)	(line 10 / line 11)	24,354.61			
			Peak Rate Total			Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	36,395.51			36,395.51
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	3,032.96			3,032.96
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	699.91			699.91
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	139.98			99.99
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	8.75			4.15

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)	66,119,792	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,737,008,985	TP	0.99785	1,733,277,022
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	5,116,015,184	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	377,371,631	W/S	0.08600	32,453,170
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	0.08600	-
6	TOTAL GROSS PLANT (sum lines 1-5)		7,296,515,593	GP=	24.200%	1,765,730,192
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	25,087,116	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	427,905,189	TP	0.99785	426,985,834
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	1,560,925,134	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	192,165,542	W/S	0.08600	16,525,834
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	0.08600	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,206,082,980			443,511,669
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	41,032,677			
14	Transmission	(line 2- line 8)	1,309,103,796			1,306,291,187
15	Distribution	(line 3 - line 9)	3,555,090,051			
16	General & Intangible	(line 4 - line 10)	185,206,090			15,927,336
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		5,090,432,613	NP=	25.975%	1,322,218,523
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 1, Col. 1 (Notes C, F)	-	NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 1, Col. 2 (Note C, F)	(410,523,282)	DA	1.00000	(410,523,282)
21	Account No. 283 (enter negative)	Attachment 5, Line 1, Col. 3 (Notes C, F)	(11,050,625)	DA	1.00000	(11,050,625)
22	Account No. 190	Attachment 5, Line 1, Col. 4 (Notes C, F)	40,366,553	DA	1.00000	40,366,553
23	Account No. 255 (enter negative)	Attachment 5, Line 1, Col. 5 (Notes C, F)	-	DA	1.00000	-
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 6, Col. 6 (Notes C & Y)	-	DA	1.00000	-
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 9, Col. 6 (Notes C & Y)	-	DA	1.00000	-
26	CWIP	216.b (Notes X & Z)	-	DA	1.00000	-
27	Unamortized Abandoned Plant	Attachment 16, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
28	TOTAL ADJUSTMENTS (sum lines 19-27)		(381,207,354)			(381,207,354)
29	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)	-	TP	0.99785	-
30	WORKING CAPITAL (Note H)					
31	CWC	1/8*(Page 3, Line 14 minus Page 3, Line 11)	7,680,797.26			4,054,251.40
32	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)	-	TE	0.95325	-
33	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)	2,131,064	GP	0.24200	515,710
34	TOTAL WORKING CAPITAL (sum lines 31 - 33)		9,811,862			4,569,961
35	RATE BASE (sum lines 18, 28, 29, & 34)		4,719,037,121			945,581,130

Period II

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Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b	32,288,618	TE	0.95325	30,779,178
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		255,960	DA	1.00000	255,960
3	Less Account 565	321.96.b	306,000	DA	1.00000	306,000
4	Less Account 566	321.97.b	(7,388,875)	DA	1.00000	(7,388,875)
5	A&G	323.197.b	35,565,079	W/S	0.08600	3,058,522
6	Less FERC Annual Fees		-	W/S	0.08600	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		5,474,418	W/S	0.08600	470,789
8	Plus Transmission Related Reg. Comm. Exp. (Note I)			TE	0.95325	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 11 (Note C)	(370,941)	DA	1.00000	(370,941)
10	Common	356.1	-	CE	0.08600	-
11	Account 566 Amortization of Regulatory Assets	321.97.b (notes)	-	DA	1.00000	-
12	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 11	(7,388,875)	DA	1.00000	(7,388,875)
13	Total Account 566 (sum lines 11 & 12, ties to 321.97.b)		(7,388,875)			(7,388,875)
14	TOTAL O&M (sum lines 1, 5,8, 9, 10, 13 less 2, 3, 4, 6, 7)		61,446,378			32,434,011
	DEPRECIATION AND AMORTIZATION EXPENSE					
15	Transmission	336.7.b (Note U)	38,470,624	TP	0.99785	38,387,970
16	General & Intangible	336.1.f & 336.10.f (Note U)	20,282,906	W/S	0.08600	1,744,287
17	Common	336.11.b (Note U)	-	CE	0.08600	-
18	Amortization of Abandoned Plant	Attachment 16, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
19	TOTAL DEPRECIATION (sum lines 15 -18)		58,753,530			40,132,257
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
20	Payroll	263.i (Attachment 7, line 1z)	11,650,873	W/S	0.08600	1,001,951
21	Highway and vehicle	263.i (Attachment 7, line 2z)	6,975	W/S	0.08600	600
22	PLANT RELATED					
23	Property	263.i (Attachment 7, line 3z)	6,340,843	GP	0.24200	1,534,461
24	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
25	Other	263.i (Attachment 7, line 5z)	3,085	GP	0.24200	747
26	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	0.24200	-
27	TOTAL OTHER TAXES (sum lines 20 - 26)		18,001,776			2,537,758
	INCOME TAXES	(Note K)				
28	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		28.11%			
29	CIT=(T/1-T) * (1-(WCLTD/R)) =		27.61%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
30	1 / (1 - T) = (from line 29)		1.3910			
31	Amortized Investment Tax Credit (266.8.f) (enter negative)		(131,199)			
32	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) (Note D)		242,045			
33	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) (Note E)		(2,196,889)			
34	Income Tax Calculation = line 29 * line 39		105,839,824	NA		21,207,746
35	ITC adjustment (line 30 * line 31)		(182,500)	NP	0.25975	(47,404)
36	Permanent Differences and AFUDC Equity Tax Adjustment (line 30 * line 32)		336,688	DA	1.00000	336,688
37	(Excess)/Deficient Deferred Income Tax Adjustment (line 30 * line 33)		(3,055,904)	DA	1.00000	(3,055,904)
38	Total Income Taxes	sum lines 34 through 37	102,938,108			18,441,126
39	RETURN	[Rate Base (page 2, line 35) * Rate of Return (page 4, line 25, col. 6)]	383,308,698.69	NA		76,805,811
40	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)	(sum lines 14, 19, 27, 38, 39)	624,448,491			170,350,964
41	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)	0			0
42	GROSS REV. REQUIREMENT	(line 40 + line 41)	624,448,491			170,350,964

Period II

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Formula Rate - Non-Levelized

Rate Formula Template
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For the 12 months ended 12/31/2020

Jersey Central Power & Light

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (page 2, line 2, column 3)						1,737,008,985		
2	Less transmission plant excluded from ISO rates (Note M)						-		
3	Less transmission plant included in OATT Ancillary Services (Note N)						3,731,963		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,733,277,022		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	0.99785		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (page 3, line 1, column 3)						32,288,618		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,443,168		
8	Included transmission expenses (line 6 less line 7)						30,845,450		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.95530		
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	0.99785		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.95325		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	-	0.00	-				
13	Transmission	354.21.b	7,056,263	1.00	7,041,103				
14	Distribution	354.23.b	58,655,533	0.00	-		W&S Allocator		
15	Other	354.24, 354.25, 354.26.b	16,163,483	0.00	-		($ / Allocation)		
16	Total (sum lines 12-15)		81,875,279		7,041,103	=	0.08600 = WS		
	COMMON PLANT ALLOCATOR (CE) (Note O)								
			$		% Electric (line 17 / line 20)		W&S Allocator (line 16, col. 6)		CE
17	Electric	200.3.c	-						
18	Gas	201.3.d	-		1.00000	*	0.08600	=	0.08600
19	Water	201.3.e	-						
20	Total (sum lines 17 - 19)		-						
	RETURN (R)						$		
21	Preferred Dividends (118.29c) (positive number)						-		
			$	%	Cost (Note P)		Weighted		
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)		1,650,629,970	47%	0.0509		0.0239 =WCLTD		
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)		-	0%	0.0000		0.0000		
24	Common Stock Attachment 8, Line 14, Col. 6) (Note X)		1,869,617,757	53%	0.1080		0.0574		
25	Total (sum lines 22-24)		3,520,247,727				0.0812 =R		
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)					
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						-		
27	b. Bundled Sales for Resale included in Divisor on page 1						-		
28	Total of (a)-(b)						-		
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)		(300.17.b)				-		
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		(300.19.b)				81,960		
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)		(330.x.n)				712,824		

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

Jersey Central Power & Light

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT.
B	Prepayments shall exclude prepayments of income taxes.
C	Transmission-related only
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of regulatory assets (page 3, line 11, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 30).

Inputs Required:	FIT =	21.00%	
	SIT=	9.00%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA., and related to generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = Attachment 10, Column (j) total. Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do no include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by its own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Page 4, Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.

Period II

Statement BK
Attachment H-4A, Attachment 1
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For the 12 months ended 12/31/2020

Schedule 1A Rate Calculation

1	$ 1,443,168	Attachment H-4A, Page 4, Line 7
2	$ 126,913	Revenue Credits for Sched 1A - Note A
3	$ 1,316,255	Net Schedule 1A Expenses (Line 1 - Line 2)
4	22,380,876	Annual MWh in JCP&L Zone - Note B
5	$ 0.0588	Schedule 1A rate $/MWh (Line 3/ Line 4)

Note:

A Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of JCP&L's zone during the year used to calculate rates under Attachment H-4A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the JCP&L zone. Data from RTO settlement systems for the calendar year prior to the rate year.

Period II

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Attachment H-4A, Attachment 2
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For the 12 months ended 12/31/2020

Incentive ROE Calculation

			Source Reference	
Return Calculation				
1	Rate Base		Attachment H-4A, page 2, Line 35, Col. 5	945,581,130
2	Preferred Dividends	enter positive	Attachment H-4A, page 4, Line 21, Col. 6	0
	Common Stock			
3	Proprietary Capital		Attachment 8, Line 14, Col. 1	3,674,649,455
4	Less Preferred Stock		Attachment 8, Line 14, Col. 2	0
5	Less Accumulated Other Comprehensive Income Account 219		Attachment 8, Line 14, Col. 4	-5,863,989
6	Less Account 216.1 & Goodwill		Attachment 8, Line 14, Col. 3 & 5	1,810,895,687
7	Common Stock		Attachment 8, Line 14, Col. 6	1,869,617,757
	Capitalization			
8	Long Term Debt		Attachment H-4A, page 4, Line 22, Col. 3	1,650,629,970
9	Preferred Stock		Attachment H-4A, page 4, Line 23, Col. 3	0
10	Common Stock		Attachment H-4A, page 4, Line 24, Col. 3	1,869,617,757
11	Total Capitalization		Attachment H-4A, page 4, Line 25, Col. 3	3,520,247,727
12	Debt %	Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 4	46.8896%
13	Preferred %	Preferred Stock	Attachment H-4A, page 4, Line 23, Col. 4	0.0000%
14	Common %	Common Stock	Attachment H-4A, page 4, Line 24, Col. 4	53.1104%
15	Debt Cost	Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 5	0.0509
16	Preferred Cost	Preferred Stock	Attachment H-4A, page 4, Line 23, Col. 5	0.0000
17	Common Cost	Common Stock		0.1080
18	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 12 * Line 15)	0.0239
19	Weighted Cost of Preferred	Preferred Stock	(Line 13 * Line 16)	0.0000
20	Weighted Cost of Common	Common Stock	(Line 14 * Line 17)	0.0574
21	Rate of Return on Rate Base (ROR)		(Sum Lines 18 to 20)	**0.0812**
22	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 21)**	**76,805,811**
Income Taxes				
	Income Tax Rates			
23	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		Attachment H-4A, page 3, Line 28, Col. 3	28.11%
24	CIT=(T/1-T) * (1-(WCLTD/R)) =		Calculated	27.61%
25	1 / (1 - T) = (from line 23)		Attachment H-4A, page 3, Line 30, Col. 3	1.3910
26	Amortized Investment Tax Credit (266.8.f) (enter negative)		Attachment H-4A, page 3, Line 31, Col. 3	(131,199.25)
27	Tax Effect of Permanent Differences and AFUDC Equity		Attachment H-4A, page 3, Line 32, Col. 3	242,044.73
28	(Excess)/Deficient Deferred Income Taxes		Attachment H-4A, page 3, Line 33, Col. 3	(2,196,889.16)
29	Income Tax Calculation		(line 22 * line 24)	21,207,745.93
30	ITC adjustment		Attachment H-4A, page 3, Line 35, Col. 5	(47,403.61)
31	Permanent Differences and AFUDC Equity Tax Adjustment		Attachment H-4A, page 3, Line 36, Col. 5	336,687.62
32	(Excess)/Deficient Deferred Income Tax Adjustment		Attachment H-4A, page 3, Line 37, Col. 5	(3,055,903.69)
33	Total Income Taxes		Sum lines 29 to 32	18,441,126.26
Increased Return and Taxes				
34	Return and Income taxes with increase in ROE		(Line 22 + Line 33)	95,246,937.12
35	Return without incentive adder		Attachment H-4A, Page 3, Line 39, Col. 5	76,805,810.86
36	Income Tax without incentive adder		Attachment H-4A, Page 3, Line 38, Col. 5	18,441,126.26
37	Return and Income taxes <u>without</u> increase in ROE		Line 35 + Line 36	95,246,937.12
38	Return and Income taxes with increase in ROE		Line 34	95,246,937.12
39	Incremental Return and incomes taxes for increase in ROE		Line 38 - Line 37	-
40	Rate Base		Line 1	945,581,130.31
41	Incremental Return and incomes taxes for increase in ROE divided by rate base		Line 39 / Line 40	-

Notes:

Line 17 to include an incentive ROE that is used only to determine the increase in return and incomes taxes associated with a specific increase in ROE. Any actual ROE incentive must be approved by the Commission. Until an ROE incentive is approved, line 17 will reflect the current ROE.

Period II

Statement BK
Attachment H-4A, Attachment 3
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For the 12 months ended 12/31/2020

Gross Plant Calculation

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2019		65,664,771	1,680,641,203	5,022,857,976	130,840,338	237,606,634	-	7,137,610,921
2	January	2020		65,702,563	1,687,974,268	5,038,038,578	130,926,303	238,368,774	-	7,161,010,485
3	February	2020		65,729,169	1,690,688,677	5,052,552,093	130,954,929	239,365,530	-	7,179,290,398
4	March	2020		65,744,576	1,693,172,844	5,066,586,416	135,805,534	240,145,749	-	7,201,455,118
5	April	2020		65,761,093	1,701,712,842	5,081,516,295	135,830,277	240,674,458	-	7,225,494,965
6	May	2020		65,777,851	1,704,349,531	5,096,843,420	135,862,423	241,118,615	-	7,243,951,838
7	June	2020		65,798,634	1,753,537,862	5,114,910,847	135,903,246	241,520,119	-	7,311,670,708
8	July	2020		65,820,872	1,755,825,300	5,131,538,873	135,917,967	241,996,462	-	7,331,099,475
9	August	2020		66,008,232	1,758,151,398	5,148,137,598	135,933,059	242,446,892	-	7,350,677,180
10	September	2020		66,224,968	1,761,075,778	5,163,960,416	135,949,131	242,828,130	-	7,370,038,423
11	October	2020		66,690,964	1,763,986,714	5,180,530,843	137,334,564	243,411,645	-	7,391,954,730
12	November	2020		67,141,503	1,803,914,332	5,196,603,995	137,361,936	243,995,320	-	7,449,017,087
13	December	2020		67,492,107	1,826,086,058	5,214,120,048	146,672,259	247,060,913	-	7,501,431,386
14	**13-month Average**		**[A] [C]**	**66,119,792**	**1,737,008,985**	**5,116,015,184**	**135,791,690**	**241,579,942**	**-**	**7,296,515,593**

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
			[B]	205.46.g	207.58.g	207.75.g	205.5.g	207.99.g	356.1	
15	December	2019		65,664,771	1,680,644,614	5,022,903,633	130,840,338	239,202,245		7,139,255,600
16	January	2020		65,702,563	1,687,977,678	5,038,084,235	130,926,303	239,964,385		7,162,655,163
17	February	2020		65,729,169	1,690,692,087	5,052,597,750	130,954,929	240,961,142		7,180,935,076
18	March	2020		65,744,576	1,693,176,254	5,066,632,072	135,805,534	241,741,360		7,203,099,797
19	April	2020		65,761,093	1,701,716,253	5,081,561,952	135,830,277	242,270,069		7,227,139,643
20	May	2020		65,777,851	1,704,352,941	5,096,889,076	135,862,423	242,714,226		7,245,596,517
21	June	2020		65,798,634	1,753,541,272	5,114,956,503	135,903,246	243,115,731		7,313,315,386
22	July	2020		65,820,872	1,755,828,710	5,131,584,530	135,917,967	243,592,074		7,332,744,153
23	August	2020		66,008,232	1,758,154,809	5,148,183,255	135,933,059	244,042,504		7,352,321,858
24	September	2020		66,224,968	1,761,079,188	5,164,006,073	135,949,131	244,423,742		7,371,683,101
25	October	2020		66,690,964	1,763,990,124	5,180,576,499	137,334,564	245,007,257		7,393,599,408
26	November	2020		67,141,503	1,803,917,743	5,196,649,652	137,361,936	245,590,932		7,450,661,766
27	December	2020		67,492,107	1,826,089,468	5,214,165,705	146,672,259	248,656,525		7,503,076,064
28	13-month Average			66,119,792	1,737,012,396	5,116,060,841	135,791,690	243,175,553	-	7,298,160,272

Asset Retirement Costs

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
			[B]	205.44.g	207.57.g	207.74.g	company records	207.98.g	company records
29	December	2019			3,410	45,657		1,595,611	
30	January	2020			3,410	45,657		1,595,611	
31	February	2020			3,410	45,657		1,595,611	
32	March	2020			3,410	45,657		1,595,611	
33	April	2020			3,410	45,657		1,595,611	
34	May	2020			3,410	45,657		1,595,611	
35	June	2020			3,410	45,657		1,595,611	
36	July	2020			3,410	45,657		1,595,611	
37	August	2020			3,410	45,657		1,595,611	
38	September	2020			3,410	45,657		1,595,611	
39	October	2020			3,410	45,657		1,595,611	
40	November	2020			3,410	45,657		1,595,611	
41	December	2020			3,410	45,657		1,595,611	
42	13-month Average			-	3,410	45,657	-	1,595,611	-

Notes:
[A] Taken to Attachment H-4A, page 2, lines 1-6, Col. 3
[B] Reference for December balances as would be reported in FERC Form 1.
[C] Balance excludes Asset Retirements Costs

Period II

Statement BK
Attachment H-4A, Attachment 4
page 1 of 1

Accumulated Depreciation Calculation

For the 12 months ended 12/31/2020

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2019		24,309,320	417,984,760	1,522,091,139	89,394,107	93,099,161	-	2,146,878,487
2	January	2020		24,442,853	419,810,687	1,528,524,213	90,241,153	93,840,303	-	2,156,859,209
3	February	2020		24,577,692	422,179,355	1,535,040,430	91,088,677	94,556,115	-	2,167,442,270
4	March	2020		24,713,817	424,583,933	1,541,615,906	91,956,531	95,296,732	-	2,178,166,919
5	April	2020		24,849,850	426,295,524	1,548,117,647	92,844,699	96,065,852	-	2,188,173,573
6	May	2020		24,985,888	428,663,114	1,554,603,055	93,733,105	96,844,792	-	2,198,829,954
7	June	2020		25,121,517	425,904,594	1,560,814,191	94,621,814	97,628,843	-	2,204,090,958
8	July	2020		25,257,025	428,407,122	1,567,215,008	95,446,470	98,404,971	-	2,214,730,596
9	August	2020		25,374,393	430,912,627	1,573,667,266	96,271,250	99,184,388	-	2,225,409,924
10	September	2020		25,488,892	433,380,630	1,580,254,478	97,096,161	99,971,861	-	2,236,192,021
11	October	2020		25,576,366	435,849,127	1,586,787,678	97,926,911	100,737,279	-	2,246,877,361
12	November	2020		25,666,456	434,208,352	1,593,404,891	98,763,547	101,503,181	-	2,253,546,427
13	December	2020		25,768,436	434,587,628	1,599,890,840	99,639,091	101,995,047	-	2,261,881,041
14	**13-month Average**		**[A] [C]**	**25,087,116**	**427,905,189**	**1,560,925,134**	**94,540,271**	**97,625,271**	**-**	**2,206,082,980**

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
			[B]	219.20-24.c	219.25.c	219.26.c	200.21.c	219.28.c	356.1	
15	December	2019		24,309,320	417,986,307	1,522,091,139	89,394,107	93,730,844		2,147,511,717
16	January	2020		24,442,853	419,812,237	1,528,524,213	90,241,153	94,478,755		2,157,499,212
17	February	2020		24,577,692	422,180,910	1,535,040,430	91,088,677	95,201,336		2,168,089,045
18	March	2020		24,713,817	424,585,491	1,541,615,906	91,956,531	95,948,721		2,178,820,468
19	April	2020		24,849,850	426,297,087	1,548,117,647	92,844,699	96,724,611		2,188,833,894
20	May	2020		24,985,888	428,664,681	1,554,603,055	93,733,105	97,510,319		2,199,497,048
21	June	2020		25,121,517	425,906,164	1,560,814,191	94,621,814	98,301,140		2,204,764,825
22	July	2020		25,257,025	428,408,696	1,567,215,008	95,446,470	99,084,036		2,215,411,235
23	August	2020		25,374,393	430,914,205	1,573,667,266	96,271,250	99,870,222		2,226,097,336
24	September	2020		25,488,892	433,382,212	1,580,254,478	97,096,161	100,664,464		2,236,886,206
25	October	2020		25,576,366	435,850,714	1,586,787,678	97,926,911	101,436,651		2,247,578,319
26	November	2020		25,666,456	434,209,942	1,593,404,891	98,763,547	102,209,322		2,254,254,158
27	December	2020		25,768,436	434,589,222	1,599,890,840	99,639,091	102,707,956		2,262,595,544
28	13-month Average			25,087,116	427,906,759	1,560,925,134	94,540,271	98,297,567	-	2,206,756,847

Reserve for Depreciation of Asset Retirement Costs

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
			[B]	Company Records	Company Records	Company Records	Company Records	Company Records	Company Records
29	December	2019			1,547			631,683	
30	January	2020			1,551			638,452	
31	February	2020			1,555			645,221	
32	March	2020			1,559			651,990	
33	April	2020			1,563			658,759	
34	May	2020			1,567			665,528	
35	June	2020			1,571			672,296	
36	July	2020			1,575			679,065	
37	August	2020			1,579			685,834	
38	September	2020			1,583			692,603	
39	October	2020			1,586			699,372	
40	November	2020			1,590			706,140	
41	December	2020			1,594			712,909	
42	13-month Average			-	1,571	-	-	672,296	-

Notes:

[A] Taken to Attachment H-4A, page 2, lines 7-11, Col. 3

[B] Reference for December balances as would be reported in FERC Form 1.

[C] Balance excludes reserve for depreciation of asset retirement costs

Period II

Statement BK
Attachment H-4A, Attachment 5
page 1 of 1
For the 12 months ended 12/31/2020

			[1]	[2]	[3]	[4]	[5]	[6]
			ADIT Transmission Total (including Plant & Labor Related Transmission ADITs and applicable transmission adjustments from notes below)					
			Acct. No. 281 (enter negative)	**Acct. No. 282** (enter negative) [B]	**Acct. No. 283** (enter negative) [C]	**Acct. No. 190** [D]	**Acct. No. 255** (enter negative) [E]	**Total**
1	December 31	2020	-	(410,523,282)	(11,050,625)	40,366,553	-	(381,207,354)
			ADIT Total Transmission-related only, including Plant & Labor Related Transmission ADITs (prior to adjusments from notes below)					
			Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
2	December 31	2020 [G]	-	299,146,653	(24,031,443)	44,328,672	1,523,750	320,967,632

Notes:

[A] Beginning/Ending Average with adjustments for FAS143, FAS106, FAS109, CIACs and normalization to populate Appendix H-4A, page 2, lines 19-23, col. 3 for accounts 281, 282, 283, 190, and 255, respectively

[B] FERC Account No. 282 is adjusted for the following items.

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
3	2020	-	620,640	(116,234,402)		4,237,132

[C] FERC Account No. 283 is adjusted for the following items.

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
4	2020	19,002	-	(35,928,497)		827,427

[D] FERC Account No. 190 is adjusted for the following items:

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
5	2020	-	-	(6,302,072)	10,692,658	(428,467)

[E] See Attachment H-4A, page 5, note K; A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f).

[F] Sourced from Attachment 5b, page 1, col. O for PTRR & Attachment 5C, page 2, col. O for ATRR

[G] Sourced from Attachment 5a, page 1, lines 1-5, col. 4

Period II

Statement BK
Attachment H-4A, Attachment 5a
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For the 12 months ended 12/31/2020

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line	1	2	3	4
		Transmission Ending	**End Plant & Labor Related Allocated to Transmission**	**Total Transmission Ending** (col. 2 + col. 3)
		(Note F)	(page 1, Col. K)	(Note E)
1	**ADIT- 282 From Account Subtotal Below**	299,146,653	-	299,146,653
2	**ADIT-283 From Account Subtotal Below**	(24,031,443)	-	(24,031,443)
3	**ADIT-190 From Account Subtotal Below**	44,328,672	-	44,328,672
4	**ADIT-281 From Account Subtotal Below**	-	-	-
5	**ADIT-255 From Account Subtotal Below**	1,523,750	-	1,523,750
	Total (sum rows 1-5)	320,967,632	-	320,967,632

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line		A	B	C	D	E	F
		End Plant Related	**End Labor Related**	**Plant & Labor Subtotal**	**Gross Plant Allocator**	**Wages & Salary Allocator**	**End Plant & Labor Related ADIT**
		(Note A)	(Note B)	Col. A + Col. B	(Note C)	(Note D)	(Col. A * Col. D) + (Col. B * Col. E)
1	ADIT- 282 From Account Total Below	-	-	-	24.20%	8.60%	-
2	ADIT-283 From Account Total Below	-	-	-	24.20%	8.60%	-
3	ADIT-190 From Account Total Below	-	-	-	24.20%	8.60%	-
4	ADIT-281 From Account Total Below	-	-	-	24.20%	8.60%	-
5	ADIT-255 From Account Total Below	-	-	-	24.20%	8.60%	-
6	**Subtotal**	-	-	-			-

Notes
A From column F (beginning on page 2)
B From column G (beginning on page 2)
C Refers to Attachment H-4A, page 2, line 6, col. 4
D Refers to Attachment H-4A, page 4, line 16, col.6
E Total Transmission Ending taken to Attachment 5, line 2
F From column E (beginning on page 2) by account

Period II

Statement BK
Attachment H-4A, Attachment 5a
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For the 12 months ended 12/31/2020

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-190	End of Year Balance p234.18.c	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Asset Impairment	5,270,265			5,270,265			
Capitalized Interest	8,557,430			8,557,430			
Contribution in Aid of Construction	10,692,658			10,692,658			
Investment Tax Credit	595,808			595,808			
FAS109 Related to Property	(6,302,072)			(6,302,072)			
Federal NOL	18,278,881			18,278,881			
NJ State NOL	7,069,693			7,069,693			
AMT Credit Carryforward	119,554			119,554			
General Business Credit Carryforward	46,455			46,455			
	-						
	-						
Subtotal	44,328,672	-	-	44,328,672	-	-	

Instructions for Account 190:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Period II

Statement BK
Attachment H-4A, Attachment 5a
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For the 12 months ended 12/31/2020

Jersey Central Power & Light

A	B	C	D	E	F	G	
ADIT- 282	End of Year Balance p275.9.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
263A Capitalized Overheads	78,686,827			78,686,827			
Accelarated Depreciation	266,529,087			266,529,087			
AFUDC	7,089,368			7,089,368			
AFUDC Equity (FAS109)	3,232,622			3,232,622			
Asset Impairment	-			-			
Capitalized Interest	-			-			
Capitalized Tree Trimming	8,452,807			8,452,807			
Casualty Loss	12,191,244			12,191,244			
Contribution in Aid of Construction	-			-			
OPEBs	620,640			620,640			
Other	972,719			972,719			
Pension and Capitalized Benefits	12,208,190			12,208,190			
Tax Repairs	28,634,975			28,634,975			
Sale of Property - Book/Tax Gain/Loss	(4,804)			(4,804)			
FAS109 Related to Property	(119,467,024)			(119,467,024)			
	-						
Subtotal	299,146,653	-	-	299,146,653	-	-	

Instructions for Account 282:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Period II

Statement BK
Attachment H-4A, Attachment 5a
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For the 12 months ended 12/31/2020

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-283	End of Year Balance p277.19.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
AFUDC Equity Flow Thru (Gross up)	1,264,000			1,264,000			
Property FAS109	(44,249,086)			(44,249,086)			
Accrued Taxes	(58,843)			(58,843)			
Accum. Prov. For Injuries and Damages	(81,216)			(81,216)			
Asset Retirement Obligation	19,002			19,002			
Company Debt - Issuance Discount	(23,004)			(23,004)			
Deferred Charge - EIB	45,460			45,460			
FAS 112 - Medical Benefit Accrual	(358,474)			(358,474)			
FAS 158 Pension & OPEB	(82,715)			(82,715)			
FE Service Timing Allocation	10,445,026			10,445,026			
Fed Rate Change - Non Property Gross-up	2,759,226			2,759,226			
GR&F Tax Audit	(81,081)			(81,081)			
Pension Expense	(5,563,028)			(5,563,028)			
PJM Payable / Receivable	-			-			
PJM Unbilled Deferral	(1,719,738)			(1,719,738)			
Post Retirement Benefits FAS 106	(3,229,826)			(3,229,826)			
State Income Tax Deductible	1,020,111			1,020,111			
Storm Damage	17,595,320			17,595,320			
Unamortized Gain/Loss on Reacquired Debt	222,781			222,781			
Vacation Accrual	(302,361)			(302,361)			
Vegetation Management	(1,652,997)			(1,652,997)			
	-			-			
Subtotal	(24,031,443)	-	-	(24,031,443)	-	-	

Instructions for Account 283:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Period II

Statement BK
Attachment H-4A, Attachment 5a
page 5 of 6
For the 12 months ended 12/31/2020

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-281	End of Year Balance p273.8.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
				-			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
Subtotal	-	-	-	-	-	-	

Instructions for Account 281:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Period II

Statement BK
Attachment H-4A, Attachment 5a
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For the 12 months ended 12/31/2020

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-255	End of Year Balance p267.h	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Investment Tax Credit	1,523,750			1,523,750			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
Subtotal	1,523,750	-	-	1,523,750	-	-	

Instructions for Account 255:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Period II

Statement BK
Attachment H-4A, Attachment 5b
page 1 of 1
For the 12 months ended 12/31/2020

Line		A	B	C	D	E	F	G	H	I
			2020 Quarterly Activity and Balances							
		Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
1	PTRR	40,194,744	184,064	40,378,808	43,215	40,422,023	41,642	40,463,665	40,990	40,504,655
		Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
2	PTRR	**40,194,744**	**139,183**		**21,904**		**10,610**		**112**	
		Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
3	PTRR	405,271,792	5,626,083	410,897,875	1,320,910	412,218,785	1,272,835	413,491,620	1,252,888	414,744,508
		Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
4	PTRR	**405,271,792**	**4,254,244**		**669,502**		**324,311**		**3,433**	
		Beginning 283 Including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
5	PTRR	10,017,938	1,106,349	11,124,287	259,752	11,384,039	250,299	11,634,338	246,376	11,880,714
		Beginning 283 Including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
6	PTRR	**10,017,938**	**836,582**		**131,655**		**63,775**		**675**	

2020 PTRR

Line		Account	J	K	L	M	N	O	P
				Page 1, B+D+F+H	Page 1, row 2,4,6 Column A+B+D+F+H	J-L		M-N	Line 7= J-N-O Lines 8-9= -J+N+O
			Estimated Ending Balance (Before Adjustments)	Projected Activity	Prorated Ending Balance	Prorated - Estimated End (Before Adjustments)	Sum of end ADIT Adjustments	Normalization	Ending ADIT Balance Included in Formula Rate
7	PTRR	Total Account 190	44,328,672	309,911	40,366,553	3,962,120	4,390,586	**(428,467)**	**40,366,553**
8	PTRR	Total Account 282	299,146,653	9,472,716	410,523,282	(111,376,629)	(115,613,762)	**4,237,132**	**(410,523,282)**
9	PTRR	Total Account 283	(24,031,443)	1,862,776	11,050,625	(35,082,067)	(35,909,495)	**827,427**	**(11,050,625)**
10	PTRR	Total ADIT Subject to Normalization	(230,786,538)	(11,025,581)	(381,207,354)	150,420,816	(147,132,670)	4,636,093	(381,207,354)

Notes:

1. Attachment 5b will only be populated within the PTRR

Period II

Statement BK
Attachment H-4A, Attachment 5c
page 1 of 2
For the 12 months ended 12/31/2020

Line		A	B	C	D	E	F	G	H	I
			2020 Quarterly Activity and Balances							
		Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
1	PTRR	0	0	0	0	0	0	0	0	0
2	ATRR	0	0	0	0	0	0	0	0	0
		Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
3	PTRR	**0**	**0**		**0**		**0**		**0**	
4	ATRR	**0**	**0**		**0**		**0**		**0**	
		Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
5	PTRR	0	0	0	0	0	0	0	0	0
6	ATRR	0	0	0	0	0	0	0	0	0
		Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
7	PTRR	**0**	**0**		**0**		**0**		**0**	
8	ATRR	**0**	**0**		**0**		**0**		**0**	
		Beginning 283 Including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
9	PTRR	0	0	0	0	0	0	0	0	0
10	ATRR	0	0	0	0	0	0	0	0	0
		Beginning 283 Including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
11	PTRR	**0**	**0**		**0**		**0**		**0**	
12	ATRR	**0**	**0**		**0**		**0**		**0**	

Period II

Statement BK
Attachment H-4A, Attachment 5c
page 2 of 2
For the 12 months ended 12/31/2020

2020 PTRR

Line		Account	A Estimated Ending Balance (Before Adjustments)	B Page 1, B+D+F+H Projected Activity	C Page 1, row 3,7,11 Column A+B+D+F+H Prorated Ending Balance	D A-C Prorated - Estimated End (Before Adjustments)	E Sum of end ADIT Adjustments	F D-E Normalization	G Line 1= A-E-F Lines 2-3= -A+E+F Ending ADIT Balance Included in Formula Rate
1	PTRR	Total Account 190	-	0	0	-	-	-	-
2	PTRR	Total Account 282	-	0	0	-	-	-	-
3	PTRR	Total Account 283	-	0	0	-	-	-	-
4	PTRR	Total ADIT Subject to Normalization	-	-	-	-	-	-	-

2020 ATRR

Line		Account	H Actual Ending Balance (Before Adjustments)	I Page 1, B+D+F+H Actual Activity	J Page 1, row 4,8,12 column A+B+D+F+H Prorated Ending Balance	K H-J Prorated - Actual End (Before Adjustments)	L D-K Prorated Activity Not Projected	M Sum of end ADIT Adjustments	N E-M ADIT Adjustments not projected	O K+L-M-N Normalization	P Line 5= H-M-O Lines 6-7= -H+M+O Ending ADIT Balance Included in Formula Rate
5	ATRR	Total Account 190	-	0	0	-	-	-	-	-	-
6	ATRR	Total Account 282	-	0	0	-	-	-	-	-	-
7	ATRR	Total Account 283	-	0	0	-	-	-	-	-	-
8	ATRR	Total ADIT Subject to Normalization	-	-	-	-	-	-	-	-	-

Notes:
1. Attachment 5c will only be populated within the ATRR

Period II

Statement BK
Attachment H-4A, Attachment 6
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For the 12 months ended 12/31/2020

1	**Calculation of PBOP Expenses**		
2	**JCP&L**	**Amount**	**Source**
3	Total FirstEnergy PBOP expenses	-$155,537,000	FirstEnergy 2018 Actuarial Study
4	Labor dollars (FirstEnergy)	$2,363,633,077	FirstEnergy 2018 Actual: Company Records
5	cost per labor dollar (line 3 / line 4)	-$0.0658	
6	labor (labor not capitalized) current year, transmission only	6,276,276	JCP&L Labor: Company Records
7	PBOP Expense for current year (line 5 * line 6)	-$413,005	
8	PBOP expense in Account 926 for current year, total company	(489,135)	JCP&L Account 926: Company Records
9	W&S Labor Allocator	8.600%	
10	Allocated Transmission PBOP (line 8 * line 9)	(42,065)	
11	PBOP Adjustment for Attachment H-4A, page 3, line 9 (line 7 - line 10)	(370,941)	
12	Lines 3-4 cannot change absent a Section 205 or 206 filing approved or accepted by FERC in a separate proceeding		

Period II

Statement BK
Attachment H-4A, Attachment 7
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For the 12 months ended 12/31/2020

Taxes Other than Income Calculation

		[A]	Dec 31, 2020
1	**Payroll Taxes**		
1a	FICA & unemployement taxes	263.i	11,650,873
1b		263.i	
1c		263.i	
1d		263.i	
1z	**Payroll Taxes Total**		11,650,873
2	**Highway and Vehicle Taxes**		
2a	Federal Excise Tax	263.i	6,975
2z	**Highway and Vehicle Taxes**		6,975
3	**Property Taxes**		
3a	New Jersey Property Tax	263.i	6,340,768
3b	PA PURTA Tax	263.i	75
3c		263.i	-
3d		263.i	-
3z	**Property Taxes**		6,340,843
4	**Gross Receipts Tax**		
4a	Gross Receipts Tax	263.i	-
4z	**Gross Receipts Tax**		-
5	**Other Taxes**		
5a	Sales & Use Tax	263.i	3,085
5b		263.i	
5c		263.i	
5d			-
5z	**Other Taxes**		3,085
6z	**Payments in lieu of taxes**		
7	Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z) [tie to 114.14c]		$18,001,776.00

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Period II

Statement BK
Attachment H-4A, Attachment 8
page 1 of 1
For the 12 months ended 12/31/2020

Capital Structure Calculation

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Proprietary Capital	**Preferred Stock**	**Account 216.1**	**Account 219**	**Goodwill**	**Common Stock**	**Long Term Debt**
			[A]	112.16.c	112.3.c	112.12.c	112.15.c	233.5.f	(1) - (2) - (3) - (4) - (5)	112.24.c
1	December	2019		3,616,361,135	-	(40,438)	(5,689,656)	1,810,936,125	1,811,155,104	1,650,811,724
2	January	2020		3,629,988,160		(40,438)	(5,718,712)	1,810,936,125	1,824,811,185	1,650,781,432
3	February	2020		3,642,398,273		(40,438)	(5,747,767)	1,810,936,125	1,837,250,353	1,650,751,139
4	March	2020		3,628,891,236		(40,438)	(5,776,823)	1,810,936,125	1,823,772,372	1,650,720,847
5	April	2020		3,638,837,224		(40,438)	(5,805,878)	1,810,936,125	1,833,747,415	1,650,690,555
6	May	2020		3,654,010,566		(40,438)	(5,834,934)	1,810,936,125	1,848,949,813	1,650,660,262
7	June	2020		3,653,946,728		(40,438)	(5,863,989)	1,810,936,125	1,848,915,030	1,650,629,970
8	July	2020		3,687,446,863		(40,438)	(5,893,045)	1,810,936,125	1,882,444,221	1,650,599,678
9	August	2020		3,719,564,976		(40,438)	(5,922,101)	1,810,936,125	1,914,591,390	1,650,569,385
10	September	2020		3,712,492,592		(40,438)	(5,951,156)	1,810,936,125	1,907,548,061	1,650,539,093
11	October	2020		3,725,041,950		(40,438)	(5,980,212)	1,810,936,125	1,920,126,475	1,650,508,801
12	November	2020		3,737,320,890		(40,438)	(6,009,267)	1,810,936,125	1,932,434,470	1,650,478,508
13	December	2020		3,724,142,321		(40,438)	(6,038,323)	1,810,936,125	1,919,284,957	1,650,448,216
14	13-month Average			3,674,649,455	-	(40,438)	(5,863,989)	1,810,936,125	1,869,617,757	1,650,629,970

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Period II

Statement BK
Attachment H-4A, Attachment 9
page 1 of 1

Stated Value Inputs

For the 12 months ended 12/31/2020

Formula Rate Protocols
Section VIII.A

1. Rate of Return on Common Equity ("ROE")

JCP&L's stated ROE is set to: 10.8%

2. Postretirement Benefits Other Than Pension ("PBOP")

**sometimes referred to as Other Post Employment Benefits, or "OPEB"*

Total FirstEnergy PBOP expenses	-$155,537,000
Labor dollars (FirstEnergy)	$2,363,633,077
cost per labor dollar	$-0.0658

3. Depreciation Rates (1)(2)

FERC Account	Depr %
350.2	1.53%
352	1.14%
353	2.43%
354	0.83%
355	1.95%
356	2.45%
356.1	1.09%
357	1.39%
358	1.88%
359	1.10%
389.2	3.92%
390.1	1.51%
390.2	0.46%
391.1	4.00%
391.15	5.00%
391.2	20.00%
391.25	20.00%
392	3.84%
393	3.33%
394	4.00%
395	5.00%
396	3.03%
397	5.00%
398	5.00%

Note: (1) Account 303 amortization period is 7 years.

(2) Accounts 391.10, 391.15, 391.20, 391.25, 393, 394, 395, 397, and 398 have an unrecovered reserve to be amortized over 5 years separately from the assets in these accounts beginning January 1, 2020 through December 31, 2025.

Period II

Statement BK
Attachment H-4A, Attachment 10
page 1 of 1
For the 12 months ended 12/31/2020

Debt Cost Calculation

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED 12/31/2020

t=N **Long Term Debt 12/31/2020** First Mortgage Bonds:	(a) Issue Date	(b) Maturity Date	(c) ORIGINAL ISSUANCE (table 2, col. cc)	(d) Net Proceeds At Issuance (table 2, col. hh)	(e) Net Amount Outstanding at t=N	(f) Months Outstanding at t=N	(g) Average Net Outstanding in Year* z* ((col e. * col. F)/12)	(h) Weighted Outstanding Ratios (col. g/col. g total)	(i) Effective Cost Rate (Table 2, Col. ll)	(j) Weighted Debt Cost at t = N (h) * (i)
(1) 6.40% Series	5/12/2006	5/15/2036	$ 200,000,000	$ 196,437,127	$ 198,174,028	12	$ 198,174,027.59	12.05%	6.54%	0.79%
(2) 6.15% Series	5/16/2007	6/1/2037	$ 300,000,000	$ 295,979,779	$ 297,803,097	12	$ 297,803,096.98	18.11%	6.25%	1.13%
(3) 4.30% Series	2/8/2019	1/15/2026	$ 400,000,000	$ 402,287,000	$ 401,667,604	12	$ 401,667,604.17	24.43%	4.20%	1.03%
(4) 4.70% Series	8/21/2013	4/1/2024	$ 500,000,000	$ 493,197,650	$ 497,937,870	12	$ 497,937,870.28	30.29%	4.87%	1.47%
(5) 4.30% Series	8/18/2015	1/15/2026	$ 250,000,000	$ 247,086,512	$ 248,589,872	12	$ 248,589,871.61	15.12%	4.44%	0.67%
			$ 1,650,000,000		$ 1,644,172,471		$ 1,644,172,471	100.000%		5.09% **

t = time

The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.

The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.

* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).

Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).

** This Total Weighted Average Debt Cost will be shown on page 4, line 22, column 5 of formula rate Attachment H-4A.

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED 12/31/2020

Long Term Debt Affiliate	(aa) Issue Date	(bb) Maturity Date	(cc) Amount Issued	(dd) (Discount) Premium at Issuance	(ee) Issuance Expense	(ff) Loss/Gain on Reacquired Debt	(gg) Less Related ADIT	(hh) Net Proceeds (col. cc + col. dd - col. ee - col. ff)	(ii) Net Proceeds Ratio ((col. hh / col. cc)*100)	(jj) Coupon Rate	(kk) Annual Interest (col. cc * col. jj)	(ll) Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
(1) 6.40% Series	5/12/2006	5/15/2036	$ 200,000,000	$ (1,216,000)	$ 2,346,873	-	xxx	$ 196,437,127	98.2186	0.0640	$ 12,800,000	6.54%
(2) 6.15% Series	5/16/2007	6/1/2037	$ 300,000,000	$ (3,693,000)	$ 327,221			$ 295,979,779	98.6599	0.0615	$ 18,450,000	6.25%
(3) 4.30% Series	2/8/2019	1/15/2026	$ 400,000,000	$ 5,884,000	$ 3,597,000			$ 402,287,000	100.5718	0.0430	$ 17,200,000	4.20%
(4) 4.70% Series	8/21/2013	4/1/2024	$ 500,000,000	$ (2,595,000)	$ 4,207,350			$ 493,197,650	98.6395	0.0470	$ 23,500,000	4.87%
(5) 4.30% Series	8/18/2015	1/15/2026	$ 250,000,000	$ (800,000)	$ 2,113,488			$ 247,086,512	98.8346	0.0430	$ 10,750,000	4.44%
TOTALS			$ 1,650,000,000	(2,420,000)	$ 12,591,932	-	xxx	$ 1,634,988,068			$ 82,700,000	

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation

Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_0 equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

Period II

Statement BK
Attachment H-4A, Attachment 11
page 1 of 2
For the 12 months ended 12/31/2020

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-4A

Line No.	(1)	(2) Reference	(3) Transmission	(4) Allocator
1	Gross Transmission Plant - Total	Attach. H-4A, p. 2, line 2, col. 5 (Note A)	$ 1,733,277,022	
2	Net Transmission Plant - Total	Attach. H-4A, p. 2, line 14, col. 5 (Note B)	$ 1,306,291,187	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-4A, p. 3, line 14, col. 5	$ 32,434,011	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)	1.871254%	1.871254%
	GENERAL, INTANGIBLE, AND COMMON (G,I, & C) DEPRECIATION EXPENSE			
5	Total G, I, & C depreciation expense	Attach. H-4A, p. 3, lines 16 & 17, col. 5	$ 1,744,287	
6	Annual allocation factor for G, I, & C depreciation expense	(line 5 divided by line 1, col. 3)	0.100635%	0.100635%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach. H-4A, p. 3, line 27, col. 5	$ 2,537,758	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col. 3)	0.146414%	0.146414%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, & 8**		**2.118303%**
	INCOME TAXES			
10	Total Income Taxes	Attach. H-4A, p. 3, line 38, col. 5	$ 18,441,126	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2, col. 3)	1.411716%	1.411716%
	RETURN			
12	Return on Rate Base	Attach. H-4A, p. 3, line 39, col. 5	$ 76,805,811	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2, col. 3)	5.879685%	5.879685%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**7.291402%**

Columns 5-9 (page 1) only applies with incentive ROE project(s) (Note F)

(5) Line No.	(6)	(7) Reference	(8) Transmission	(9) Allocator
	INCOME TAXES			
10b	Total Income Taxes	Attachment 2, line 33	$ 18,441,126	
11b	Annual Allocation Factor for Income Taxes	(line 10b divided by line 2, col. 3)	1.411716%	1.411716%
	RETURN			
12b	Return on Rate Base	Attachment 2, line 22	$ 76,805,811	
13b	Annual Allocation Factor for Return on Rate Base	(line 12b divided by line 2, col. 3)	5.879685%	5.879685%
14b	**Annual Allocation Factor for Return**	**Sum of line 11b and 13b**		**7.291402%**
15	**Additional Annual Allocation Factor for Return**	**Line 14 b, col. 9 less line 14, col. 4**		**0.00000%**

Period II

Statement BK
Attachment H-4A, Attachment 11
page 2 of 2
For the 12 months ended 12/31/2020

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-4A

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	Project Name	RTEP Project Number	Project Gross Plant	Annual Allocation Factor for Expense	Annual Expense Charge	Project Net Plant	Annual Allocation Factor for Return	Annual Return Charge	Project Depreciation Expense	Annual Revenue Requirement	Additional Incentive Annual Allocation Factor for Return (Note F)	Total Annual Revenue Requirement	True-up Adjustment	Net Revenue Requirement with True-up
1			(Note C & H)	(Page 1, line 9)	(Col. 3 * Col. 4)	(Note D & H)	Page 1, line 14	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8, & 9)	(Col. 6 * Page 1, line 15, Col. 9)	(Sum Col. 10 & 11)	(Note G)	(Sum Col. 12 & 13)
2a	Upgrade the Portland – Greystone 230kV circuit	b0174	$ 12,588,179	2.118303%	$266,656	$ 9,605,485	7.291402%	$700,374	$ 333,478	$1,300,508	0	$1,300,508		$1,300,508
2b	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	b0268	$ 5,983,501	2.118303%	$126,749	$ 4,891,189	7.291402%	$356,636	$ 158,812	$642,197	0	$642,197		$642,197
2c	Add a 2nd Raritan River 230/115 kV transformer	b0726	$ 7,324,741	2.118303%	$155,160	$ 6,471,309	7.291402%	$471,849	$ 192,824	$819,833	0	$819,833		$819,833
2d	Build a new 230 kV circuit from Larrabee to Oceanview	b2015	$ 171,769,848	2.118303%	$3,638,606	$ 160,880,601	7.291402%	$11,730,451	$3,955,448	$19,324,505	0	$19,324,505		$19,324,505
3	Transmission Enhancement Credit taken to Attachment H-4A Page 1, Line 7											$22,087,043		
4	Additional Incentive Revenue taken to Attachment H-4A, Page 3, Line 41										$0.00			

Notes
A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-4A.
B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-4A.
C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 above. This value includes subsequent capital investments required to maintain the project in-service.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-4A, page 3, line 15.
F Any actual ROE incentive must be approved by the Commission
G True-up adjustment is calculated on the project true-up schedule, attachment 12 column j
H Based on a 13-month average

Period II

TEC Worksheet Support
Net Plant Detail

Statement BK
Attachment H-4A, Attachment 11a
page 1 of 2
For the 12 months ended 12/31/2020

Line No.	Project Name	RTEP Project Number	Project Gross Plant	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
			(Note A)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)
2a	Upgrade the Portland – Greystone 230kV circuit	b0174	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179
2b	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	b0268	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501
2c	Add a 2nd Raritan River 230/115 kV transformer	b0726	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741
2d	Build a new 230 kV circuit from Larrabee to Oceanview	b2015	$ 171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848

NOTE

[A] Project Gross Plant is the total capital investment for the project, including subsequent capital investments required to maintain the project in-service. Utilizing a 13-month average.

[D] Company records

Period II

TEC Worksheet Support
Net Plant Detail

Statement BK
Attachment H-4A, Attachment 11a
page 2 of 2
For the 12 months ended 12/31/2020

Accumulated Depreciation	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	[redacted]	**Project Net Plant**
(Note B)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)		(Note B & C)
$ 2,982,694	$ 2,828,781	$ 2,854,434	$ 2,880,086	$ 2,905,738	$ 2,931,390	$ 2,957,042	$ 2,982,694	$ 3,008,346	$ 3,033,998	$ 3,059,650	$ 3,085,303	$ 3,110,955	$ 3,136,607		$9,605,485
$ 1,092,312	$ 1,019,014	$ 1,031,230	$ 1,043,446	$ 1,055,663	$ 1,067,879	$ 1,080,095	$ 1,092,312	$ 1,104,528	$ 1,116,744	$ 1,128,961	$ 1,141,177	$ 1,153,393	$ 1,165,609		$4,891,189
$ 853,432	$ 764,436	$ 779,269	$ 794,102	$ 808,934	$ 823,767	$ 838,599	$ 853,432	$ 868,265	$ 883,097	$ 897,930	$ 912,762	$ 927,595	$ 942,428		$6,471,309
$ 10,889,247	$9,063,655	$9,367,921	$9,672,186	$9,976,451	$10,280,716	$10,584,982	$10,889,247	$11,193,512	$11,497,777	$11,802,043	$12,106,308	$12,410,573	$12,714,838		$160,880,601

NOTE
[B] Utilizing a 13-month average.
[C] Taken to Attachment 11, Page 2, Col. 6
[D] Company records

Period II

Statement BK
Attachment H-4A, Attachment 12
page 1 of 1
For the 12 months ended 12/31/2020

TEC - True-up
To be completed after Attachment 11 for the True-up Year is updated using actual data

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.		Project Name	RTEP Project Number	Actual Revenues for Attachment 11	Projected Annual Revenue Requirement	% of Total Revenue Requirement	Revenue Received	Actual Annual Revenue Requirement	True-up Adjustment Principal Over/(Under)	Applicable Interest Rate on Over/(Under)	Total True-up Adjustment with Interest Over(Under)
					Projected Attachment 11 p 2 of 2, col. 14	Col d, line 2 / Col. d, line 3	Col c, line 1 * Col e	Actual Attachment 11 p 2 of 2, col. 14	Col. f - Col. G	Col. H line 2x / Col. H line 3 * Col. J line 4	Col. h + Col. i
1	[A]	Actual RTEP Credit Revenues for true-up year		0							
2a		Project 1			-	-	-	-	-	#DIV/0!	#DIV/0!
2b		Project 2				-	-		-	#DIV/0!	#DIV/0!
2c		Project 3				-	-		-	#DIV/0!	#DIV/0!
3		Subtotal			-			-	-		#DIV/0!
4		Total Interest (Sourced from Attachment 13a, line 30)									-

NOTE
[A] Amount included in revenues reported on pages 328-330 of FERC Form 1.

Period II

Statement BK
Attachment H-4A, Attachment 13
page 1 of 1
For the 12 months ended 12/31/2020

Net Revenue Requirement True-up with Interest

	Reconciliation Revenue Requirement For Year 2018 Available June 10, 2019		2018 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2017		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.0000%				
	An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorate over 2020							
	Calculation of Interest					Monthly		
3	January	Year 2018	-	0.0000%	12	-		-
4	February	Year 2018	-	0.0000%	11	-		-
5	March	Year 2018	-	0.0000%	10	-		-
6	April	Year 2018	-	0.0000%	9	-		-
7	May	Year 2018	-	0.0000%	8	-		-
8	June	Year 2018	-	0.0000%	7	-		-
9	July	Year 2018	-	0.0000%	6	-		-
10	August	Year 2018	-	0.0000%	5	-		-
11	September	Year 2018	-	0.0000%	4	-		-
12	October	Year 2018	-	0.0000%	3	-		-
13	November	Year 2018	-	0.0000%	2	-		-
14	December	Year 2018	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 2019	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
16	January	Year 2020	-	0.0000%		-	-	-
17	February	Year 2020	-	0.0000%		-	-	-
18	March	Year 2020	-	0.0000%		-	-	-
19	April	Year 2020	-	0.0000%		-	-	-
20	May	Year 2020	-	0.0000%		-	-	-
21	June	Year 2020	-	0.0000%		-	-	-
22	July	Year 2020	-	0.0000%		-	-	-
23	August	Year 2020	-	0.0000%		-	-	-
24	September	Year 2020	-	0.0000%		-	-	-
25	October	Year 2020	-	0.0000%		-	-	-
26	November	Year 2020	-	0.0000%		-	-	-
27	December	Year 2020	-	0.0000%		-	-	-
						-		
28	True-Up with Interest						$ -	
29	Less Over (Under) Recovery						$ -	
30	Total Interest						$ -	

[A] Interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if JCP&L does not have short term debt

Period II

Statement BK
Attachment H-4A, Attachment 13a
page 1 of 1
For the 12 months ended 12/31/2020

TEC Revenue Requirement True-up with Interest

	TEC Reconciliation Revenue Requirement For Year 2018 Available June 10, 2019		TEC 2018 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2017		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.0000%				
	An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorate over 2020							
	Calculation of Interest					Monthly		
3	January	Year 2018	-	0.0000%	12	-		-
4	February	Year 2018	-	0.0000%	11	-		-
5	March	Year 2018	-	0.0000%	10	-		-
6	April	Year 2018	-	0.0000%	9	-		-
7	May	Year 2018	-	0.0000%	8	-		-
8	June	Year 2018	-	0.0000%	7	-		-
9	July	Year 2018	-	0.0000%	6	-		-
10	August	Year 2018	-	0.0000%	5	-		-
11	September	Year 2018	-	0.0000%	4	-		-
12	October	Year 2018	-	0.0000%	3	-		-
13	November	Year 2018	-	0.0000%	2	-		-
14	December	Year 2018	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 2019	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
16	January	Year 2020	-	0.0000%		-	-	-
17	February	Year 2020	-	0.0000%		-	-	-
18	March	Year 2020	-	0.0000%		-	-	-
19	April	Year 2020	-	0.0000%		-	-	-
20	May	Year 2020	-	0.0000%		-	-	-
21	June	Year 2020	-	0.0000%		-	-	-
22	July	Year 2020	-	0.0000%		-	-	-
23	August	Year 2020	-	0.0000%		-	-	-
24	September	Year 2020	-	0.0000%		-	-	-
25	October	Year 2020	-	0.0000%		-	-	-
26	November	Year 2020	-	0.0000%		-	-	-
27	December	Year 2020	-	0.0000%		-	-	-
						-		
28	True-Up with Interest						$ -	
29	Less Over (Under) Recovery						$ -	
30	Total Interest						$ -	

[A] Interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if JCP&L does not have short term debt

Period II

Statement BK
Attachment H-4A, Attachment 14
page 1 of 1

Other Rate Base Items

For the 12 months ended 12/31/2020

			[1]	[2]	[3]	[4]	[5]	[6]
			Land Held for Future Use	**Materials & Supplies**	**Prepayments (Account 165)**		**Total**	
		[A]	214.x.d	227.8.c & .16.c	111.57.c [B]			
1	December 31	2019	-	-	2,131,064		2,131,064	
2	December 31	2020	-	-	2,131,064		2,131,064	
3	Begin/End Average		-	-	2,131,064		2,131,064	

					Unfunded Reserve - Plant Related			**Total**
	FERC Acct No.		**228.1**	**228.2**	**228.3**	**228.4**	**242**	
		[A] [C]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c	
4	December 31	2019	-	-	-	-	-	-
5	December 31	2020	-	-	-	-	-	-
6	Begin/End Average		-	-	-	-	-	-

					Unfunded Reserve - Labor Related			**Total**
	FERC Acct No.		**228.1**	**228.2**	**228.3**	**228.4**	**242**	
		[A] [C]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c	
7	December 31	2019	-	-	-	-	-	-
8	December 31	2020	-	-	-	-	-	-
9	Begin/End Average		-	-	-	-	-	-

Notes:
[A] Reference for December balances as would be reported in FERC Form 1.
[B] Prepayments shall exclude prepayments of income taxes.
[C] Includes transmission-related balance only

Period II

Statement BK
Attachment H-4A, Attachment 15
page 1 of 1
For the 12 months ended 12/31/2020

Income Tax Adjustments

	[1]	[2]	[3] Dec 31, 2020	Reference
1	Tax adjustment for Permanent Differences & AFUDC Equity	[A] [C]	242,045	JCP&L Company Records
2	Amortized Excess Deferred Taxes (enter negative)	[B] [C]	(2,196,889)	JCP&L Company Records
3	Amortized Deficient Deferred Taxes	[B] [C]	-	JCP&L Company Records

Notes:

[A] AFUDC equity component is the gross cumulative annual amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function.

[B] Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. The balance located within Column 3, row 2 and row 3, is the net impact of excess deferred and deficient amortization.

[C] Year end balance for line 1 taken to Attachment H-4A, page 3, line 32; Year end balance for lines 2-3 taken to Attachment H-4A, page 3, line 33

Period II

Statement BK
Attachment H-4A, Attachment 15a
page 1 of 1
For the 12 months ended 12/31/2020

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Line No.	Description	EDIT Transmission Allocation	Amortization Period	Years Remaining at Year End	Amortization of EDIT	Protected (P) Non-Protected (N)
1	Accrued Taxes: FICA on Vacation Accrual	8,680	10	7	868	N
2	Accrued Taxes: Tax Audit Reserves	6,238	10	7	624	N
3	Accum Prov For Inj and Damage-Gen Liability	15,386	10	7	1,539	N
4	Accum Prov For Inj and Damage-Workers Comp	50,817	10	7	5,082	N
5	Asset Retirement Obligation Liability	(1,647)	10	7	(165)	N
6	Company Debt - Issuance Discount	16,436	10	7	1,644	N
7	Deferred Charge-EIB	(15,677)	10	7	(1,568)	N
8	FAS 112 - Medical Benefit Accrual	165,849	10	7	16,585	N
9	FAS 158 OPEB OCI Offset	(22,157)	10	7	(2,216)	N
10	FAS 158 Pension OCI Offset	1,790	10	7	179	N
11	FE Service Tax Interest Allocation	(712)	10	7	(71)	N
12	FE Service Timing Allocation	(503,373)	10	7	(50,337)	N
13	Federal Long Term NOL	5,037,433	35	32	143,927	P
14	Federal Long Term NOL	6,981,827	10	7	698,183	N
15	GR&F Tax Audit	36,747	10	7	3,675	N
16	NOL Deferred Tax Asset - LT NJ	(106,781)	10	7	(10,678)	N
17	Pension/OPEB : Other Def Cr. or Dr.	2,289,854	10	7	228,985	N
18	Pensions Expense	2,716,133	10	7	271,613	N
19	PJM Receivable	(1,381,762)	10	7	(138,176)	N
20	Post Retirement Benefits SFAS 106 Accrual	3,107,222	10	7	310,722	N
21	Post Retirement Benefits SFAS 106 Payments	(1,090,624)	10	7	(109,062)	N
22	Sale of Property - Book Gain or (Loss)	89,727	10	7	8,973	N
23	Sale of Property - Tax Gain or (Loss)	(94,435)	10	7	(9,444)	N
24	State Income Tax Deductible	(680,043)	10	7	(68,004)	N
25	Storm Damage	(6,198,498)	10	7	(619,850)	N
26	Unamortized Gain on Reacquired Debt	1,606	10	7	161	N
27	Unamortized Loss on Reacquired Debt	(204,887)	10	7	(20,489)	N
28	Vacation Pay Accrual	95,018	10	7	9,502	N
29	Vegetation Management	(29,221)	10	7	(2,922)	N
30	**Total Non-Property Amortization (Total of lines 1 thru 29)**				**669,278**	
31	**Property Book-Tax Timing Difference [B] [C]**				(2,866,167)	N & P
32	**Total Non-Property & Property Amortization [A] [B] [C]**				**(2,196,889)**	N & P

Notes:

Above amortization is populated from company records

[A] Ties to Attachment 15, page 1, line 2, column 3 for net excess & Attachment 15, page 1, line 3, Column 3 for net deficient

[B] The amortization schedule of the EDIT balance related to Tax Cuts and Job Act of 2017 shall be consistent with the following periods:

Protected Property & Non-Protected Property	ARAM
Non-Protected, Non-Property:	10 years
Protected, Non-Property:	35 years

[C] The regulatory assets and liabilities, included in FERC accounts 182.3 and 254, respectively, will amortize through FERC income statement accounts 410.1 and 411.1

Period II

Statement BK
Attachment H-4A, Attachment 16
page 1 of 1
For the 12 months ended 12/31/2020

Abandoned Plant

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
2	December 2019	p111.71.d (and Notes)	13				-
3	January	FERC Account 182.2	12	-	-	-	-
4	February	FERC Account 182.2	11	-	-	-	-
5	March	FERC Account 182.2	10	-	-	-	-
6	April	FERC Account 182.2	9	-	-	-	-
7	May	FERC Account 182.2	8	-	-	-	-
8	June	FERC Account 182.2	7	-	-	-	-
9	July	FERC Account 182.2	6	-	-	-	-
10	August	FERC Account 182.2	5	-	-	-	-
11	September	FERC Account 182.2	4	-	-	-	-
12	October	FERC Account 182.2	3	-	-	-	-
13	November	FERC Account 182.2	2	-	-	-	-
14	December 2020	p111.71.c (and Notes) Detail on p230b	1	-	-	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$0.00		$0.00
					Attachment H-4A, page 3, Line 18		Attachment H-4A, page 2, Line 27

Note:

Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC and will be zero until the Commission accepts or approves recovery of the cost of abandoned plant

Period II

Statement BK
Attachment H-4A, Attachment 17
page 1 of 1
For the 12 months ended 12/31/2020

			CWIP
			[A]
			216.b
1	December	2019	
2	January	2020	
3	February	2020	
4	March	2020	
5	April	2020	
6	May	2020	
7	June	2020	
8	July	2020	
9	August	2020	
10	September	2020	
11	October	2020	
12	November	2020	
13	December	2020	
14	13-month Average		-

Notes:

[A] Includes only CWIP authorized by the Commission for inclusion in rate base.

Period II

Statement BK
Attachment H-4A, Attachment 18
page 1 of 1
For the 12 months ended 12/31/2020

Federal Income Tax Rate

Nominal Federal Income Tax Rate (entered on Attachment H-4A, page 5 of 5, Note K)	21.00%

State Income Tax Rate

	New Jersey	Combined Rate (entered on Attachment H-4A, page 5 of 5, Note K)
Nominal State Income Tax Rate	9.00%	
Times Apportionment Percentage	100.00%	
Combined State Income Tax Rate	9.000%	9.000%

Period II

Statement BK
Attachment H-4A, Attachment 19
page 1 of 1
For the 12 months ended 12/31/2020

Regulatory Asset

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (Company Records)	Additions (Deductions)	Ending Balance
2	December 2019	p232 (and Notes)	13				-
3	January	FERC Account 182.3	12	-	-	-	-
4	February	FERC Account 182.3	11	-	-	-	-
5	March	FERC Account 182.3	10	-	-	-	-
6	April	FERC Account 182.3	9	-	-	-	-
7	May	FERC Account 182.3	8	-	-	-	-
8	June	FERC Account 182.3	7	-	-	-	-
9	July	FERC Account 182.3	6	-	-	-	-
10	August	FERC Account 182.3	5	-	-	-	-
11	September	FERC Account 182.3	4	-	-	-	-
12	October	FERC Account 182.3	3	-	-	-	-
13	November	FERC Account 182.3	2	-	-	-	-
14	December 2020	p232 (and Notes)	1	-	-	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$0.00	-	$0.00

Period II

Statement BK
Attachment H-4A, Attachment 20
page 1 of 2
For the 12 months ended 12/31/2020

Operation and Maintenance Expenses

FF1 Page 321 Line No.	**Account Reference**	**Description**	**Account Balance [A]**
82		***Operation***	
83	560	Operation Supervision and Engineering	$306,210
84			
85	561.1	Load Dispatch-Reliability	$1,220,421
86	561.2	Load Dispatch-Monitor and Operate Transmission System	$222,747
87	561.3	Load-Dispatch-Transmission Service and Scheduling	
88	561.4	Scheduling, System Control and Dispatch Services	$246,660
89	561.5	Reliability, Planning and Standards Development	$570,765
90	561.6	Transmission Service Studies	$55,682
91	561.7	Generation Interconnection Studies	-$626,846
92	561.8	Reliability, Planning and Standards Development Services	$9,300
93	562	Station Expenses	
94	563	Overhead Lines Expense	$903,726
95	564	Underground Lines Expense	
96	565	Transmission of Electricity by Others	$306,000
97	566	Miscellaneous Transmission Expense	-$7,388,875
98	567	Rents	$10,387,615
99		TOTAL Operation (Enter Total of Lines 83 thru 98)	$6,213,405
100		***Maintenance***	
101	568	Maintenance Supervision and Engineering	$3,094,294
102	569	Maintenance of Structures	
103	569.1	Maintenance of Computer Hardware	$22,115
104	569.2	Maintenance of Computer Software	$27,442
105	569.3	Maintenance of Communication Equipment	
106	569.4	Maintenance of Miscellaneous Regional Transmission Plant	
107	570	Maintenance of Station Equipment	$4,040,963
108	571	Maintenance of Overhead Lines	$18,879,685
109	572	Maintenance of Underground Lines	
110	573	Maintenance of Miscellaneous Transmission Plant	$10,714
111		TOTAL Maintenance (Total of lines 101 thru 110)	$26,075,213
112		**TOTAL Transmission Expenses (Total of lines 99 and 111)**	**$32,288,618**

Notes:
[A] December balances as would be reported in FERC Form 1

Administrative and General (A&G) Expenses

FF1 Page 323 Line No.	Account Reference	Description	Account Balance [B]
180		***Operation***	
181	920	Administrative and General Salaries	-$45,147
182	921	Office Supplies and Expenses	$78,157
183	Less 922	Administrative Expenses Transferred - Credit	
184	923	Outside Services Employed	$3,975,503
185	924	Property Insurance	$24,239
186	925	Injuries and Damages	$259,311
187	926	Employee Pensions and Benefits	-$2,183,646
188	927	Franchise Requirements	
189	928	Regulatory Commission Expense	$408,174
190	Less 929	(Less) Duplicate Charges-Cr.	
191	930.1	General Advertising Expenses	$62,614
192	930.2	Miscellaneous General Expenses	$222,802
193	931	Rents	$55,193
194		**Total Operation (Enter Total of lines 181 thru 193)**	$2,857,200
195		***Maintenance***	
196	935	Maintenance of General Plant	$201,322
197		**TOTAL A&G Expenses (Total of lines 194 and 196)**	**$3,058,522**

Notes:
[B] December balances as would be reported in FERC Form 1, transmission only

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jersey Central Power & Light Company	)	Docket No. ER20-___-000

ATTESTATION OF MICHAEL T. FALEN
(18 C.F.R. § 35.13(d)(6))

I, Michael T. Falen, attest that I am Director of Transmission Business Services in the FirstEnergy Utilities Finance Group within the Controller's Group of the FirstEnergy Service Company and that, to the best of my knowledge, information, and belief, the cost of service statements and supporting data submitted by Jersey Central Power & Light Company ("JCP&L") are true, accurate, and current representations of JCP&L's books, budgets, or other corporate documents.

Executed on October 23, 2019.

Michael T. Falen

Subscribed and sworn before me this 23rd day of October, 2019.

Notary Public

NOTARIAL SEAL
STATE OF OHIO

Terese M. Miller
Resident Summit County
Notary Public, State of Ohio
My Commission Expires: 04/07/2020

Service Company Agreement-Utility Execution Copy

SERVICE AGREEMENT

This Service Agreement ("Agreement") is entered into as of the 31st day of January, 2017, 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 law's 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.

[Remainder of this page intentionally left blank.]

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed effective as of the 31st day of January, 2017. This Agreement supersedes any previous agreement between the Service Company and the Client Companies.

FirstEnergy Service Company

By: Steven R. Staub
Steven R. Staub
Vice President and Treasurer

[Remainder of this page intentionally left blank.]

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
Mid-Atlantic Interstate Transmission, LLC

By: Steven E. Strah
Steven E. Strah
President

[Remainder of this page intentionally left blank.]

Jersey Central Power & Light Company

By: ______________________________
James V. Fakult
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	Indiregct 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

REVISED AMENDED AND RESTATED MUTUAL ASSISTANCE AGREEMENT

THIS REVISED AMENDED AND RESTATED MUTUAL ASSISTANCE AGREEMENT, dated as of January 31, 2017, between and among JERSEY CENTRAL POWER & LIGHT COMPANY ("***JCP&L***"), METROPOLITAN EDISON COMPANY ("***Met-Ed***"), PENNSYLVANIA ELECTRIC COMPANY ("***Penelec***"), PENNSYLVANIA POWER COMPANY ("***Penn Power***"), OHIO EDISON COMPANY ("***Ohio Ed***"), THE CLEVELAND ELECTRIC ILLUMINATING COMPANY ("***CEI***"), THE TOLEDO EDISON COMPANY ("***Toledo Ed***"), FIRSTENERGY SERVICE COMPANY ("***FESC***"), GPU NUCLEAR, INC. [1] ("***GPUN***"), FIRSTENERGY NUCLEAR OPERATING COMPANY ("***FENOC***"), AMERICAN TRANSMISSION SYSTEMS, INCORPORATED ("**ATSI**"), FIRSTENERGY PROPERTIES, INC. ("***FE Properties***"), BAY SHORE POWER COMPANY ("***Bay Shore***"), FIRSTENERGY GENERATION, LLC ("***GenCo***"), WEST PENN POWER COMPANY ("***West Penn***"), MONONGAHELA POWER COMPANY ("***Mon Power***"), THE POTOMAC EDISON COMPANY ("***Potomac Ed***"), TRANS-ALLEGHENY INTERSTATE LINE COMPANY ("***TrAILCo***"), MID-ATLANTIC INTERSTATE TRANSMISSION, LLC ("**MAIT**") AND FIRSTENERGY TRANSMISSION, LLC, and its subsidiaries ("***FirstEnergy Transmission***") (each individually a "***Company***" or a "Party" and collectively the "***Companies***" or "Parties"), each a subsidiary of FirstEnergy Corp. ("***FirstEnergy***"), a public utility holding company under the Public Utility Holding Company Act of 2005 (the "***PUHCA 2005***"), and their subsidiaries.

RECITALS

WHEREAS, on October 1, 1982, the Pennsylvania Public Utility Commission ("***PaPUC***" or **"Commission"**) at Docket No. G-820167 approved pursuant to the then Section 701.1 of the Pennsylvania Public Utility Law – now Section 2102 of the Pennsylvania Public Utility Code an agreement between Met-Ed and Penelec with respect to the exchange of services and goods by and between them and their affiliated companies such as, by way of example: (a) design, engineering, construction, operation, maintenance and fuel procurement for coal-fired generating stations; (b) other fossil fuel generation services; (c) lab testing, research and development, engineering and support services for generation, transmission and distribution, construction and maintenance; (d) microfilming; (e) records retention and storage; and (f) goods incidental to such services (the "***1982 Agreement***"); and

WHEREAS, on December 17, 1993, the PaPUC at Docket No. G-00930355 approved, as a supplement to the 1982 Agreement, an agreement between Met-Ed, Penelec, JCP&L, GPU Service Corporation ("***GPUS***") and GPU Nuclear Corporation (collectively Met-Ed, Penelec, JCP&L, GPUS and GPU Nuclear Corporation are referred to as the "***GPU Companies***") pursuant to Section 2102 of

[1] GPU Nuclear Corporation was renamed GPU Nuclear, Inc. in 1996.

the Pennsylvania Public Utility Code, 66 Pa.C.S. § 2102, with respect to the exchange of services and goods by and between them such as: (a) reprographics services; (b) restoration, maintenance and repair services for generation, transmission and distribution facilities; (c) remittance processing services; (d) treasury services; (e) accounts payable services; (f) use of office, warehouse, storage and other space or facilities; (g) data processing and other computer services; (h) legal services; and (i) goods, including, electric generation, other production, transmission, distribution, office, administrative and general plant materials, supplies and equipment not "in place" or "installed" (the "***1993 MAA***"); and **WHEREAS**, as a result of the FirstEnergy/GPU merger in November 2001 (the "***FirstEnergy/GPU Merger***"), FirstEnergy became a registered holding company under the Public Utility Holding Company Act of 1935 and FESC was formed to replace GPUS as the primary provider of various corporate, managerial and administrative support services within the FirstEnergy holding company system, and the PaPUC on February 4, 2003, in Docket No. G-00020987 approved Met-Ed, Penelec and Penn Power entering into a new service agreement with FESC (the "***Existing FESC Service Agreement***"), which is not altered, modified or changed by this Amended and Restated Mutual Assistance Agreement; and

WHEREAS, as a result of the FirstEnergy/GPU Merger, FESC provides services within the FirstEnergy holding company system under the Existing FESC Service Agreement that include the following services (or the management of such services): executive services, accounting and finance, internal auditing, various treasury functions, risk management, human resources, corporate affairs, government affairs, environmental, corporate communications, operations management, supply chain, information technology, construction, maintenance, customer service, regulated commodity sourcing, FERC policy and compliance, energy efficiency, corporate real estate, records management, asset oversight, strategic planning and operations, rates and regulatory affairs, flight operations, performance management, business development, investment management and legal services; and

WHEREAS, as a result of the FirstEnergy/GPU Merger, Ohio Ed, CEI, Toledo Ed and Penn Power became affiliates of Met-Ed and Penelec in the same relationship, as affiliated operating companies within the FirstEnergy holding company system, that Met-Ed, Penelec and JCP&L theretofore had with each other within the GPU holding company system as public utility companies engaged in the transmission, distribution and sale of electricity to and for the public in their respective service territories; and

WHEREAS, as a result of the merger of Allegheny Energy, Inc. ("***Allegheny***") and a subsidiary of FirstEnergy on February 25, 2011 (the "***FirstEnergy/Allegheny Merger***"), West Penn, Mon Power, Potomac Ed, and the Trans Allegheny Interstate Line Company also became affiliated operating companies in the same relationship as other affiliated operating companies within the FirstEnergy holding system; and

WHEREAS, FirstEnergy Transmission and Penelec, Met-Ed, and JCP&L have entered into operating and capital contribution agreements regarding the formation, operation and their respective membership interests in, MAIT and, as a result of which MAIT has also become an affiliated operating company in the same relationship as other affiliated operating companies within the FirstEnergy holding system (collectively, Ohio Ed, CEI, Toledo Ed, Penn Power, JCP&L, Met-Ed, Penelec, West

Penn, Mon Power, Potomac Ed, ATSI, TrAILCo, and MAIT are referred to herein as the "***Operating Companies***");

WHEREAS, from time to time, the Operating Companies may request and/or may require non-power goods and services from one or more of the other Operating Companies ; and

WHEREAS, from time to time, GPUN, FESC, and FirstEnergy Transmission may request and/or may require goods and services from the Operating Companies and, to the degree not addressed in another agreement, GPUN, and FirstEnergy Transmission may provide non-power goods and services to the Operating Companies; and

WHEREAS, in light of changes outlined above and because from time to time various opportunities arise for the Companies to effect economies and better utilization of available resources through transfers of a broader range of goods and services by, between and among the Companies, the Companies desire to enter into this Amended and Restated Mutual Assistance Agreement, which supersedes any other agreements that may have existed between the parties hereto related to the matters covered by this Amended and Restated Mutual Assistance Agreement, as applicable, for providing mutual services by and between them.

NOW, THEREFORE, the Companies, intending to be legally bound, agree as follows:

1. **SERVICES**. As used herein "***Services***" refers to the list of services set forth in Attachment I hereto. Additional services sought to be included within this Amended and Restated Mutual Assistance Agreement will first be filed with the PaPUC for Commission review.

2. **GOODS**. As used herein "***Goods***" refers to goods incidental to the Services, electric transmission, distribution, office, administrative and general plant materials, supplies and equipment not "in place" or "installed." As contemplated hereunder, transactions in Goods may, but need not be, incidental to the provision of Services.

3. **REQUESTS FOR GOODS AND SERVICES**. From time to time, each Company, in its sole discretion may determine, may request, or, upon the request of another Company, may furnish to such other Company, upon the terms and conditions set forth herein, one or more of the Goods or Services (including, in the case of Goods, those which at the time are inadequate, obsolete, unfit, or unnecessary or unadapted for use in the operations of the Company to which such request is made).

4. **PRICING**.

(a) All transactions carried out pursuant hereto shall be effected as follows:

(i) if an Operating Company furnishes Goods or Services to an Operating Company, then such furnishing Company shall be paid for such Goods or Services at cost in the case of the performance of Services (including all applicable direct and indirect costs of the furnishing Company), or cost less accumulated depreciation in the case of the sale of Goods (including all applicable direct and indirect costs of the furnishing Company);

(ii) if an Operating Company furnishes Goods or Services to FESC , the Operating Company shall be paid for such Goods or Services at the higher of (A) cost in the case of the performance of Services (including all applicable direct and indirect costs of the furnishing Company), or cost less depreciation in the case of the sale of Goods (including all applicable direct and indirect costs of the furnishing Company) or (B) market price; and

(iii) (A) if an Operating Company furnishes Goods or Services to GPUN, FENOC, FE Properties, Bay Shore or GenCo, then the furnishing Company shall be paid for such Goods or Services at a price that is the higher of cost or market price; or (B) if GPUN, FENOC, FE Properties, Bay Shore or GenCo furnishes Goods or Services to an Operating Company, then the furnishing Company shall be paid for such Goods or Services at a price that is no higher than market price. (b) Costs include, as applicable, wages and salaries of employees and related fringe benefit expenses (such as health care, life insurance, payroll taxes, pensions and other employee welfare expenses), equipment, tooling, materials, subcontract costs, overheads, cost of capital, and taxes.

5. **BILLING, PAYMENT AND ACCOUNTING.**

(a) Costs are accumulated within the Companies' integrated accounting system related to the Services and Goods provided hereunder in order to support the inter-company billing, which shall be performed monthly. Details supporting each transaction are contained within the integrated accounting system, in accordance with applicable FirstEnergy procedures and processes, as amended from time to time.

(b) Direct charges to a Company shall be made so far as charges can be identified and related to the particular transactions involved without excessive effort or expense. Whenever possible, charges for Services rendered hereunder between the Companies, including personnel and non-personnel costs and expenses and related costs and expenses that relate to a particular requesting Company, shall be billed by the providing Company directly to such requesting Company. For those charges that cannot be direct billed either because the Services giving rise to those charges are provided to, or on behalf of, more than one recipient Company or the charges themselves are not easily susceptible to precise identification with a particular or specific transaction, the providing Company shall allocate such costs in accordance with an allocation method recommended and provided by FESC from among its approved allocation methods (which is attached hereto as Attachment II) as such methods may be amended, modified or changed from time to time.

(c) To the extent a Company is required to pay cost for Goods or Services, as provided in Section 4 of this Agreement, such costs:

(i) shall not exceed a fair and equitable allocation of expenses (including the price paid for goods) plus reasonable compensation for necessary capital procured through the issuance of capital stock (or similar securities);

(ii) for Services rendered by a providing Company shall be determined and calculated based upon the time records of employees, and records of related expenses, including out-of-pocket expenses that are billed at cost;

(iii) may include taxes, interest, other overhead, and compensation for the use of capital procured by the issuance of capital stock (or similar securities), which shall be fairly and equitably allocated. Interest on borrowed capital and compensation for the use of capital shall represent a reasonable return on only the amount of capital reasonably necessary for the performance of services or construction for, or the selling of goods to, customers for whom transactions are performed at cost. Such amount shall not include the cost of assignment of, or any capitalization of, any service, sales, or construction contract; and

(iv) shall not include any expense (including the price paid for goods) incurred in a transaction with an affiliated Company of the providing Company, to the extent that it exceeds the cost of such transaction to such affiliated Company.

(d) Inter-Company billing is performed with the close of each month and will be payable within thirty days following such monthly closing. For the sale of Goods, asset transfer documentation is completed and the transaction is included in the monthly intercompany billing. The detailed records, related to the rendering of, and payment for, the Goods or Services, supporting the inter-company bills are available within the integrated system, so that the receiving Company can reasonably determine the nature and extent of the Services or Goods provided by the providing Company, including the rates, hours and related cost elements applicable to such Service or Good.

(e) Payments shall be made by cash remittance from the receiving Company to the providing Company or by appropriate accounting transfer entries on the books of both Companies, which are reconciled daily, in accordance with applicable FirstEnergy policies and procedures.

(f) Any amount remaining unpaid after thirty (30) days following receipt of the bill shall bear interest thereon from the date of the bill until payment at such rate as would apply in accordance with applicable FirstEnergy policies and procedures.

(g) Inter-Company billings hereunder shall be reconciled each month to assure that all expenses have been billed, and also in order to detect and correct over- or under-billings.

(h) The Internal Auditing Department shall periodically audit inter-Company transactions and billings hereunder. The audits shall also include an evaluation of the work order process in order to assure that transactions and charges have been properly authorized, calculated, allocated, if applicable, invoiced, recorded, paid and tracked.

(i) The supporting records and details related to all inter-company billings, including direct charges and allocated charges, and applicable allocation methods (in order to enable testing with respect to cost allocations to and from affiliates), will be retained for auditing purposes in accordance with applicable law and regulation.

6. **WAIVER**. To the extent that the Goods and Services are furnished at cost, or cost less depreciation, if any pursuant to Section 4, and to facilitate the undertaking of this Agreement, each Company expressly waives any right it may have to recover from the other Companies for any losses, damages, penalties, liabilities, claims or expenses (including damage to its own property or liabilities to third parties) for any cause whatsoever including without limitation the negligence of the other Companies, its employees and agents in connection with the provision of Goods and Services that are furnished at cost.

7. **TERMINATION**. This Amended and Restated Mutual Assistance Agreement shall be effective on the date of execution, or such later date as approved by the applicable regulatory authority, and will remain in effect until December 31, 2016. This initial term will be automatically extended for successive periods of one year unless any Party gives sixty days' notice of termination to the other Parties prior to the end of the calendar year then in effect. Unless otherwise agreed by the Parties, such termination shall not affect or excuse the performance of transactions entered into on behalf of either Party prior to notice of termination. This Agreement shall remain in effect until all Parties have fully performed their obligations under said transactions.

8. **MODIFICATION OR AMENDMENT**. No amendment, change or modification to this Amended and Restated Mutual Assistance Agreement shall be valid, unless made in writing and signed by the Parties hereto, and upon the receipt of any required regulatory approvals as described in Paragraph 9 below.

9. **REGULATORY APPROVALS; STATE LAW**. The provision of Goods or Services hereunder by, and for, any Operating Company hereto shall be subject to the receipt of any other regulatory approvals which may pertain to, or be necessary for, a particular Operating Company or transaction involving a particular Operating Company.. This Amended and Restated Mutual Assistance Agreement, and any amendments thereto, shall be subject to the approval of any state commission or other regulatory body whose approval is, by the laws of said jurisdiction, a legal prerequisite to an Operating Company's execution, delivery and/or performance of this Amended and Restated Mutual Assistance Agreement for any particular Operating Company hereunder, and any transactions hereunder shall be in compliance with applicable state laws and regulations.

10. **GOVERNING LAW**. For purposes of providing Goods or Services hereunder, in the case of each transaction hereunder, this Amended and Restated Mutual Assistance Agreement shall be governed by, and construed under, the laws of the state in which are located the principal offices of the Company providing the Goods or Services hereunder, without regard to its conflict of laws provisions.

11. **ASSIGNMENT**. This Amended and Restated Mutual Assistance Agreement shall inure to the benefit and shall be binding upon the undersigned parties and their respective successors and assigns. No assignment of this Amended and Restated Mutual Assistance Agreement or of any Party's rights, interests or obligations hereunder, may be made without the other Parties' consent, which shall not be unreasonably withheld, delayed or conditioned.

12. **ENTIRE AGREEMENT**. This Amended and Restated Mutual Assistance Agreement together with its attachments, constitutes the entire understanding and agreement of the Parties with respect to its subject matter, and effective upon the execution of this Amended and Restated Mutual Assistance 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 (a) the transactions thereunder have taken place prior to the effective date in which case such agreements will govern the terms of such transactions, and (b) the Existing FESC Service Agreement is considered an agreement with respect to this subject matter, it shall not be terminated. In the event of any conflict between the provisions of this Agreement and the Existing FESC Agreement, the provisions of the Existing FESC Agreement will control.

13. **SEVERABILITY**. If any provision of this Amended and Restated Mutual Assistance 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 executed this Amended and Restated Mutual Assistance Agreement on of the date first above written:

JERSEY CENTRAL POWER & LIGHT COMPANY

By: ______________________
James V. Fakult
President

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METROPOLITAN EDISON COMPANY
PENNSYLVANIA ELECTRIC COMPANY
PENNSLVANIA POWER COMPANY
OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY
WEST PENN POWER COMPANY
MONONGAHELA POWER COMPANY
THE POTOMAC EDISON COMPANY
MID-ATLANTIC INTERSTATE TRANSMISSION, LLC
TRANS-ALLEGHENY INTERSTATE LINE COMPANY
FIRSTENERGY TRANSMISSION, LLC
AMERICAN TRANSMISSION SYSTEMS, INCORPORATED

By: Steven E. Strah
Steven E. Strah
President

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GPU NUCLEAR, INC.

By: Steven R. Staub

Steven R. Staub
Vice President and Treasurer

[Remainder of this page intentionally left blank.]

FIRSTENERGY SERVICE COMPANY

By: James F. Pearson

James F. Pearson
Executive Vice President and Chief Financial Officer

[Remainder of this page intentionally left blank.]

FIRSTENERGY NUCLEAR OPERATING COMPANY

By: ______________________
Jason L. Lisowski
Controller and Treasurer

[Remainder of this page intentionally left blank.]

FIRSTENERGY PROPERTIES, INC.

By: James F. Pearson
James F. Pearson
President and Chief Financial Officer

[Remainder of this page intentionally left blank.]

BAY SHORE POWER COMPANY

By: James F. Pearson
James F. Pearson
Executive Vice President and Chief Financial Officer

[Remainder of this page intentionally left blank.]

FIRSTENERGY GENERATION LLC

By: ______________________________
Jason J. Lisowski
Controller and Treasurer

ATTACHMENT I

SERVICES

As used herein "***Services***" refers to the following list of services, which a Company may request, or, upon the request of another Company, may furnish to such other Company:

Product or Service	**Product / Service Description**	**Indirect Allocation Methods**
Engineering, Operating, Maintenance and Management Services	Design, engineering, commission, construction, operation, restoration, corrective and preventative maintenance, repair, testing and nonpower services incidental to transmission and distribution facilities (including substation and line maintenance), generation facilities operations and maintenance (including personnel to perform such services), and asset management services.	Multiple Factor - Utility Multiple Factor – Non-Utility Multiple Factor – Utility and Non-Utility Direct Charge Ratio
Engineering Support Services	Lab testing, research and development, engineering and support services for transmission and distribution, construction and maintenance facilities, functions and activities.	Multiple Factor - Utility Multiple Factor – Non-Utility Multiple Factor – Utility and Non-Utility Direct Charge Ratio
Use of Space	Use or lease of office, warehouse, storage and other space or facilities, and associated warehousing and storage services.	Multiple Factor - Utility Multiple Factor – Non-Utility Multiple Factor – Utility Direct Charge Ratio
Regional Support Services	Utilize utility operations level experience to provide regional support related to utility operations functions including in connection with providing Engineering Services, Human Resource Services, Facilities Services, Regional Claim Services, Labor Contract Negotiation Services, Area Managers, and related utility operations' functions.	Multiple Factor - Utility Multiple Factor – Non-Utility Multiple Factor – Utility Direct Charge Ratio

Product or Service	Product / Service Description	Indirect Allocation Methods
Storm Support Services	Utilize utility operations level experience to provide storm support services including storm-related construction and reconstruction, operations and line restoration services to address storm-related conditions	Multiple Factor - Utility Multiple Factor – Non-Utility Multiple Factor – Utility Direct Charge Ratio
Environmental Services	Provide services and assistance related to identifying, managing and remediating environmental threats or risks.	Multiple Factor - Utility Multiple Factor – Non-Utility Multiple Factor – Utility Direct Charge Ratio
Communications/Software Services	Services include pagers, cell phones, computers, radios, I-Pads, laptops, software and hardware.	Multiple Factor – Utility Direct Charge Ratio
Meter Services	Provide services related to maintenance, operation, engineering, testing and repair of meters and related equipment.	Multiple Factor – Utility Direct Charge Ratio
Transportation and Garage Services	Provide services related to transportation maintenance practices and support.	Multiple Factor - Utility Multiple Factor – Non-Utility Multiple Factor – Utility Direct Charge Ratio
Forestry and Vegetation Management Services	Provide services related to forestry and vegetation management such as routine pruning, controlling or removing of vegetation as required to maintain line reliability, maintain access, make repairs, or restore service.	Multiple Factor - Utility Multiple Factor – Non-Utility Multiple Factor – Utility Direct Charge Ratio
Microfilming Services	Provide services related to microfilm storage and retrieval.	Multiple Factor – Utility Direct Charge Ratio
Records Retention and Storage	Provide services related to records storage, records retrieval, records retention and records planning.	Multiple Factor – Utility Direct Charge Ratio
Reprographics Services	Provide services related to production printing, document imaging and graphic services.	Multiple Factor – Utility Direct Charge Ratio

Product or Service	Product / Service Description	Indirect Allocation Methods
Remittance Processing	Provide services related to processing customer payments and depositing funds.	Number of Payments Ratio
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

ATTACHMENT II

List of FirstEnergy Service Company Allocation Methods as approved by the Securities and Exchange Commission as of as of June 1, 2003.

METHODS OF ALLOCATION

1. Multiple Factor – All

   A. FirstEnergy will bear 5% of these Indirect Allocations. The remaining Indirect Allocations will be allocated among the Utility and the Non-Utility Subsidiaries based on FirstEnergy's equity investment in the respective groups.

   B. 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 - NonUtility" method.

2. Multiple Factor – Utility

   Based on the sum of the weighted averages of the following factors:

   A. Gross transmission and/or distribution plant

   B. Operating and maintenance expense excluding purchased power and fuel costs

   C. Transmission and/or distribution revenues, excluding transactions with affiliates

   Each of the above factors will be weighted equally so that no one facet of the utility operations inordinately influences the distribution of costs

3. Multiple Factor - Non-Utility

   Based upon the total assets of each Non-Utility Subsidiary, including the generating assets under operating leases to the Utility Subsidiaries.

4. Multiple Factor - Utility and Non-Utility

   A. First assign a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in the respective groups.

   B. 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.

5. 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.

6. Number of Customers Ratio

Based on the number of Utility distribution customers for the respective Utility Subsidiary receiving the product or service divided by the total number of Utility distribution customers.

7. Number of Shopping Customers Ratio

Based on the number of shopping customers for the respective Utility Subsidiary receiving the product or service divided by the total number of shopping customers.

8. Number of Participating Employees – General

Based on the number of participating employees for the respective Subsidiary receiving the product or service divided by the total number of participating employees.

9. Number of Participating Employees - Utility and Non-Utility

A. First assign a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in the respective groups.

B. Costs are further allocated by using the number of participating employees for the respective Subsidiary divided by the total number of participating FirstEnergy employees.

10. Gigabytes Used Ratio

Based on the 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.

11. Number of Computer Workstations Ratio

Based on the 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.

12. Number of Billing Inserts Ratio

Based on the 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.

13. Number of Invoices Ratio

Based on the 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.

14. Number of Payments Ratio

Based on the 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.

15. Daily Print Volume

Based on the 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.

16. Number of Intel Servers

Based on the 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.

17. Application Development Ratio

Based on the 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.

18. Server Support Composite

Based on the average ratio of UNIX gigabytes, SAP gigabytes and Intel number of servers for a Subsidiary receiving the service.

Agenda Date: 9/11/19
Agenda Item: 2B

Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Post Office Box 350
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

ENERGY

IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER AND LIGHT COMPANY FOR APPROVAL OF THE SALE AND CONVEYANCE OF CERTAIN PORTIONS OF ITS PROPERTY IN SOUTH BRUNSWICK TOWNSHIP, MIDDLESEX COUNTY, NEW JERSEY AND THE TRANSFER OF A CERTAIN LICENSE IN CONNECTION THEREWITH PURSUANT TO N.J.S.A. 48:3-7 AND N.J.A.C. 14:1-5.6	ORDER APPROVING SALE OF REAL PROPERTY DOCKET NO. EM19030357

Parties of Record:

Stefanie A. Brand, Esq., Director, New Jersey Division of Rate Counsel
Michael J. Connolly, Esq., Cozen O'Connor, on behalf of Jersey Central Power & Light Company

BY THE BOARD:

BACKGROUND

On March 19, 2019, Jersey Central Power & Light Company ("JCP&L" or "Company") filed a petition with the New Jersey Board of Public Utilities ("Board"), pursuant to N.J.S.A. 48:3-7 and N.J.A.C. 14:1-5.6, seeking approval of the sale of certain property in South Brunswick Township, Middlesex County, New Jersey, (the "South Brunswick Property") to BH of South Brunswick, LLC ("Buyer") for a purchase price of $7,500,018.

The South Brunswick Property is a 15.24 acre property situated at 351-369 Deans Rhode Hall Road and is designated as Block 21.01, Lot 38.01 on the municipal tax map. The South Brunswick Property was originally acquired on September 19, 1973 for $240,000 for the purpose of siting, constructing, operating, and maintaining a 500 kV transmission line, which has been utilized continuously since 1978. The South Brunswick Property is not income producing except for the relatively minimal income derived from a tree farm license agreement.

The closing of the sale of the South Brunswick Property is contingent upon JCP&L's reservation of certain easements including the right to perform vegetation management and maintain facilities within these easements.

Pursuant to N.J.A.C. 14:1-5.6, JCP&L asserts that the South Brunswick Property is not used or useful to the Company and the transaction will not compromise the ability of the Company to render safe, adequate and proper service.

In May 2018, JCP&L engaged the services of Ten-X, which provides an online real estate transaction marketplace, in an attempt to maximize the pool of buyers and the sales price for the South Brunswick Property. "For Sale" signs were placed on the South Brunswick Property beginning on October 17, 2018. In addition, the South Brunswick Property was advertised for sale on November 1, 2018 and on November 8, 2018 in both the Home News Tribune and the Newark Star Ledger. The Company indicated that seven (7) bids were received by the due date of November 29, 2018 and the highest bid was accepted.

On December 7, 2018, the Company and Buyer entered into a purchase and sale agreement ("Contract") for the sale of the South Brunswick Property for $7,500,018 to be paid at the closing. The purchase price is considered more than fair market value based on the results of the marketing, advertising, and sales process and is in excess of the appraised value.

JCP&L will retain several easements on the South Brunswick Property for continued unimpeded transmission, communications, and other utility operations on and over the South Brunswick Property so that it may continue to provide safe, adequate and proper service to customers. The easements that will be retained by the Company are as follows:

1. An exclusive 200 foot wide easement over the portion of the South Brunswick Property used to operate and maintain a 500 kV transmission line;

2. A non-exclusive 15 foot wide easement along the southern border of the South Brunswick Property for future use, including communication purposes to support JCP&L utility system operations;

3. A non-exclusive 20 foot wide easement extending from the southern border of the South Brunswick Property and running in a northern direction ending at, and including a 50 foot x 52 foot segment along the western portion of the South Brunswick Property for communication purposes to support JCP&L utility system operations.

By correspondence dated July 15, 2019, the New Jersey Division of Rate Counsel ("Rate Counsel") submitted comments on the petition. In its comments, Rate Counsel did not object to the sale of the South Brunswick Property. However, Rate Counsel stated that it was not convinced that there was adequate justification to permanently deny ratepayers a share in the gains. As such, Rate Counsel requested that the Board order JCP&L to treat the gains from the sale of the South Brunswick Property as a regulatory liability that can be addressed in the next rate case before the Federal Energy Regulatory Commission ("FERC"). Rate Counsel further reserved its rights in proceedings before FERC concerning the rate treatment of the sale proceeds.

By correspondence dated July 17, 2019, JCP&L submitted a reply to the comments made by Rate Counsel. JCP&L agreed with Rate Counsel that FERC is the appropriate jurisdiction for addressing the rate treatment of the sale proceeds. For that reason, JCP&L did not object to Rate Counsel's reservation of rights before FERC, where FERC's rules and regulations would control. However, JCP&L stated that the condition set forth in the comments regarding the gains from the sale is unnecessary and inappropriate because the Board does not have jurisdiction to create regulatory liabilities relative to utility plant, property, and equipment that is classified as transmission for ratemaking purposes. JCP&L also expressed concern that Rate Counsel was effectively asking the Board to interfere with FERC's exclusive ratemaking authority relative to transmission by creating a regulatory liability for the proceeds from the sale.

DISCUSSION AND FINDINGS

After careful review and consideration of the petition, exhibits, discovery and comments submitted in this matter, the Board **HEREBY FINDS** that the sale of the South Brunswick Property by JCP&L to the Buyer will not adversely affect the public interest and will not affect the Company's ability to render safe, adequate and reliable service. The sale of the South Brunswick Property will reduce the Company's costs by eliminating the need for continued payment of taxes and maintenance on the South Brunswick Property and the Company will retain easements needed for access to electrical facilities.

The Board recognizes that all parties acknowledge the Board's regulatory authority over the approval of this land sale. Notably, Rate Counsel agrees that the sale is in accordance with Board regulations and that the terms of the easement will allow JCP&L to maintain proper service to its customers.

The parties agree that rates for transmission assets are governed by FERC's rate regulatory authority. Nonetheless, the Board acknowledges the dispute between the parties regarding the rate treatment of the sale proceeds arising in this docket. Rate Counsel contends that ratepayers should share in the proceeds. JCP&L contends that the gains are assignable to shareholders, not ratepayers. As evidenced in other proceedings,[1] the gains from the sale of transmission-related property are not guaranteed to shareholders. Rate Counsel believes that the gains from the sale of the South Brunswick Property should be treated as a regulatory liability due to this dispute, while JCP&L contends that it is unnecessary, if not extra-jurisdictional, for the Board to take such action. As noted above, all parties concede that resolution of this dispute is appropriately within the jurisdiction of FERC. Therefore, in light of this dispute regarding the rate treatment, the Board finds that it is appropriate to preserve this issue for further review in JCP&L's next FERC rate case. The Board **HEREBY ORDERS** JCP&L to take all necessary steps to preserve this issue for FERC's review in the Company's next rate proceeding at FERC and to provide FERC a copy of this Order in that next rate

[1] See In re the Petition of Public Service Electric and Gas Company for Approval of the Sale and Conveyance of Real Property Located on 148 Upper Hibernia Road, Rockaway Township, New Jersey With a Municipal Tax Map Designation of Block 30201 Lot 31, in the Township of Rockaway, County of Morris and State of New Jersey, to Stephen and Laura Treutlein for the Sum of $300,000, BPU Docket No. EM16060605 (August 24, 2016); *see also* Letter Order from FERC Chief Accountant to Old Dominion Electric Cooperative, Docket No. AC19-76-000 (June 18, 2019) (approving ODEC's proposal to recently account for gain on the sale of electric plant in Account 421.1 and amortize the return of that gain to ratepayers in ODEC's wholesale power rates).

proceeding. The Board also retains the right to challenge the treatment of the sale proceeds in any future FERC rate recovery proceeding. The Board notes that JCP&L does not object to Rate Counsel's reservation of rights to dispute this issue in proceedings before FERC.

Accordingly, the Board **HEREBY APPROVES** the Contract for the sale of the South Brunswick Property to the Buyer in the amount of $7,500,018 with the net proceeds being accounted for in accordance with the applicable federal regulation.

The approval granted hereinabove shall be subject to the following provisions:

1. This Order is based upon the specific and particular facts of this transaction and shall not have precedential value in future land transactions that may come before the Board and shall not be relied on as such.

2. JCP&L shall notify the Board and Rate Counsel if it anticipates any material changes in the Contract for sale of the South Brunswick Property.

3. The Board and Rate Counsel retain all rights to review all costs and proceeds related to the purchase of and sale of the South Brunswick Property in JCP&L's next base rate case or other appropriate proceeding, including before FERC.

4. This Order shall not affect nor in any way limit the exercise of the authority of the Board or of this State, in any future petition or in any proceedings with respect to rates, franchises, service, financing, accounting, capitalization, depreciation, or in any other matters affecting JCP&L.

5. This Order shall not be construed as directly or indirectly fixing for any purposes whatsoever any value of any tangible or intangible assets or liabilities now owned or hereafter to be owned by the Company.

6. Within thirty (30) days of the date of the closing on this transaction, the Company shall file with the Board proof of the closing, net transaction costs, and final journal entries along with a detailed calculation, including selling expenses, of the sale.

The Company's costs remain subject to audit by the Board. This Decision and Order shall not preclude nor prohibit the Board from taking any actions determined to be appropriate as a result of any such audit.

Agenda Date: 9/11/19
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This Order shall be effective on September 21, 2019.

DATED: 9\11\19

BOARD OF PUBLIC UTILITIES
BY:

JOSEPH L. FIORDALISO
PRESIDENT

MARY-ANNA HOLDEN
COMMISSIONER

DIANNE SOLOMON
COMMISSIONER

UPENDRA J. CHIVUKULA
COMMISSIONER

ROBERT M. GORDON
COMMISSIONER

ATTEST:

AIDA CAMACHO-WELCH
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities.

Agenda Date: 9/11/19
Agenda Item: 2B

IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR APPROVAL OF THE SALE AND CONVEYANCE OF CERTAIN PORTIONS OF ITS PROPERTY IN SOUTH BRUNSWICK TOWNSHIP, MIDDLESEX COUNTY, NEW JERSEY AND THE TRANSFER OF A CERTAIN LICENSE IN CONNECTION THEREWITH PURSUANT TO N.J.S.A. 48:3-7 AND N.J.A.C. 14:1-5.6.
DOCKET NO. EM19030357

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Agenda Date: 9/11/19
Agenda Item: 2B

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PROTECTIVE AGREEMENT

This Protective Agreement ("Agreement") is entered into this ___ day of ______________, _______ by and between _________________("Applicant") and _________________ ("Intervenor"), and shall govern the use of all Privileged Materials produced by Applicant to Intervenor, or vice versa, in connection with the proceeding before the Federal Energy Regulatory Commission (the "Commission") in Docket No. _____________. Applicant and Intervenor are sometimes referred to herein individually as a "Party" or jointly as the "Parties."

1. Applicant filed in the above-referenced proceeding Privileged Material and/or Critical Energy/Electric Infrastructure Information ("CEII"), as those terms are defined herein. Intervenor is a Participant in such proceeding, as the term Participant is defined in 18 C.F.R. Section 385.102(b), or has filed a motion to intervene or a notice of intervention in such proceeding. Applicant and Intervenor enter into this Agreement to govern the use of Privileged Material and/or CEII produced by, or on behalf of, Applicant and/or Intervenor in the above-referenced proceeding. Notwithstanding any order terminating such proceeding, this Agreement shall remain in effect unless and until specifically modified or terminated by the Commission or a court of competent jurisdiction.

2. The Commission's regulations[1] and its policy governing the labelling of controlled unclassified information ("CUI"),[2] establish and distinguish the respective designations of Privileged Material and CEII. As to these designations, this Agreement provides that a Party:

A. *may* designate as Privileged Material any material which customarily is treated by that Party as commercially sensitive or proprietary or material subject to a legal privilege, which is not otherwise available to the public, and which, if disclosed, would subject that Party or its customers to risk of competitive disadvantage or other business injury; and

B. *must* designate as CEII, any material that meets the definition of that term as provided by 18 C.F.R. §§ 388.113(a), (c).

3. For the purposes of this Agreement, the listed terms are defined as follows:

A. Party and Parties: As defined above.

B. Privileged Material:[3]

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[1] *Compare* 18 C.F.R. § 388.112 *with* 18 C.F.R. § 388.113.

[2] *Notice of Document Labelling Guidance for Documents Submitted to or Filed with the Commission or Commission Staff*, 82 Fed. Reg. 18632 (Apr. 20, 2017) (issued by Commission Apr. 14, 2017).

[3] The Commission's regulations state that "[f]or the purposes of the Commission's filing requirements, non-CEII subject to an outstanding claim of exemption from disclosure under FOIA, . . ., will be referred to as privileged material." 18 C.F.R. § 388.112(a). The regulations further state that "[f]or material filed in proceedings set for trial-

i. Material (including depositions) provided by a Party in response to discovery requests or filed with the Commission, and that is designated as Privileged Material by such Party;[4]

ii. Material that is privileged under federal, state, or foreign law, such as work-product privilege, attorney-client privilege, or governmental privilege, and that is designated as Privileged Material by such Party;[5]

iii. Any information contained in or obtained from such designated material;

iv. Any other material which is made subject to this Agreement by a Presiding Administrative Law Judge ("Presiding Judge") or the Chief Administrative Law Judge ("Chief Judge") in the absence of a Presiding Judge or where no presiding judge is designated, the Commission, any court, or other body having appropriate authority, or by agreement of the Parties (subject to approval by the relevant authority);

v. Notes of Privileged Material (memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses Privileged Material);[6] or

vi. Copies of Privileged Material.

vii. Privileged Material does not include:

    a. Any information or document that has been filed with and accepted into the public files of the Commission, or contained in the public files of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be privileged by such agency or court;

    b. Information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Agreement; or

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type hearing or settlement judge proceedings, a participant's access to material for which privileged treatment is claimed is governed by the presiding official's protective order." 18 C.F.R. § 388.112(b)(2)(v).

4 *See infra* P 11 for the procedures governing the labeling of this designation.

5 The Commission's regulations state that "[a] presiding officer may, by order … restrict public disclosure of discoverable matter in order to . . . [p]reserve a privilege of a participant. . . ." 18 C.F.R. § 385.410(c)(3). To adjudicate such privileges, the regulations further state that "[i]n the absence of controlling Commission precedent, privileges will be determined in accordance with decisions of the Federal courts with due consideration to the Commission's need to obtain information necessary to discharge its regulatory responsibilities." 18 C.F.R. § 385.410(d)(1)(i).

6 Notes of Privileged Material are subject to the same restrictions for Privileged Material except as specifically provided in this Agreement.

c. Any information or document labeled as "Non-Internet Public" by a Party, in accordance with Paragraph 30 of Commission Order No. 630.[7]

C. Critical Energy/Electric Infrastructure Information ("CEII"): As defined at 18 C.F.R. §§ 388.113(a), (c).

D. Non-Disclosure Certificate: The certificate attached to this Agreement, by which persons granted access to Privileged Material and/or CEII must certify their understanding that such access to such material is provided pursuant to the terms and restrictions of this Agreement, and that such persons have read the Agreement and agree to be bound by it. All executed Non-Disclosure Certificates must be provided to the Parties.

E. Reviewing Representative: A person who has signed a Non-Disclosure Certificate and who is:

i. Commission Trial Staff designated as such in this proceeding;

ii. An attorney who has made an appearance in this proceeding for a Party;

iii. Attorneys, paralegals, and other employees associated for purposes of this case with an attorney who has made an appearance in this proceeding on behalf of a Party;

iv. An expert or an employee of an expert retained by a Party for the purpose of advising, preparing for, submitting evidence or testifying in this proceeding;

v. A person designated as a Reviewing Representative by order of a Presiding Judge, the Chief Judge, or the Commission; or

vi. Employees or other representatives of Parties appearing in this proceeding with significant responsibility for this docket.

4. Privileged Material and/or CEII shall be made available under the terms of this Agreement only to Parties and only to their Reviewing Representatives as provided in Paragraphs 6-10 of this Agreement. The contents of Privileged Material, CEII, or any other form of information that copies or discloses such materials shall not be disclosed to anyone other than in accordance with this Agreement and shall be used only in connection with this specific proceeding.

5. All Privileged Material and/or CEII must be maintained in a secure place. Access to those materials must be limited to Reviewing Representatives specifically authorized pursuant to Paragraphs 7-9 of this Agreement.

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[7] FERC Stat. & Reg. ¶31,140.

6. Privileged Material and/or CEII must be handled by each Party and by each Reviewing Representative in accordance with the Non-Disclosure Certificate executed pursuant to Paragraph 9 of this Agreement. Privileged Material and/or CEII shall not be used except as necessary for the conduct of this proceeding, nor shall they (or the substance of their contents) be disclosed in any manner to any person except a Reviewing Representative who is engaged in this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Privileged Material and/or CEII, but such copies automatically become Privileged Material and/or CEII. Reviewing Representatives may make notes of Privileged Material, which shall be treated as Notes of Privileged Material if they reflect the contents of Privileged Material.

7. If a Reviewing Representative's scope of employment includes any of the activities listed under this Paragraph 7, such Reviewing Representative may not use information contained in any Privileged Material and/or CEII obtained in this proceeding for a commercial purpose (e.g., to give a Party or competitor of any Party a commercial advantage):

A. Energy marketing;

B. Direct supervision of any employee or employees whose duties include energy marketing; or

C. The provision of consulting services to any person whose duties include energy marketing.

8. In the event that a Party wishes to designate a person not described in Paragraph 3.E above as a Reviewing Representative, the Party must seek agreement from the Party providing the Privileged Material and/or CEII. If an agreement is reached, the designee shall be a Reviewing Representative pursuant to Paragraph 3.D of this Agreement with respect to those materials. If no agreement is reached, the matter must be submitted to a Presiding Judge, the Chief Judge, or the Commission for resolution.

9. A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Privileged Material and/or CEII pursuant to this Agreement until three business days after that Reviewing Representative first has executed and served a Non-Disclosure Certificate.[8] However, if an attorney qualified as a Reviewing Representative has executed a Non-Disclosure Certificate, any participating paralegal, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. Attorneys designated Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this Agreement, and must take all reasonable precautions to ensure that Privileged Material and/or CEII are not disclosed to unauthorized persons. All executed Non-Disclosure Certificates must be served on the Parties.

[8] During this three-day period, a Party may file an objection with the other Party, a Presiding Judge or the Commission contesting that an individual qualifies as a Reviewing Representative, and the individual shall not receive access to the Privileged Material and/or CEII until resolution of the dispute.

10. Any Reviewing Representative may disclose Privileged Material and/or CEII to any other Reviewing Representative as long as both Reviewing Representatives have executed a Non-Disclosure Certificate. In the event any Reviewing Representative to whom Privileged Material and/or CEII are disclosed ceases to participate in this proceeding, or becomes employed or retained for a position that renders him or her ineligible to be a Reviewing Representative under Paragraph 3.D of this Agreement, access to such materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Agreement and the Non-Disclosure Certificate for as long as the Agreement is in effect.[9]

11. All Privileged Material and/or CEII in this proceeding filed with the Commission, submitted to a Presiding Judge, or submitted to any Commission personnel, must comply with the Commission's *Notice of Document Labelling Guidance for Documents Submitted to or Filed with the Commission or Commission Staff*.[10] Consistent with those requirements:

A. Documents that contain Privileged Material must include a top center header on each page of the document with the following text: CUI//PRIV. Any corresponding electronic files must also include this text in the file name.

B. Documents that contain CEII must include a top center header on each page of the document with the following text: CUI//CEII. Any corresponding electronic files must also include this text in the file name.

C. Documents that contain both Privileged Material and CEII must include a top center header on each page of the document with the following text: CUI//CEII/PRIV. Any corresponding electronic files must also include this text in the file name.

D. The specific content on each page of the document that constitutes Privileged Material and/or CEII must also be clearly identified. For example, lines or individual words or numbers that include both Privileged Material and CEII shall be prefaced and end with "BEGIN CUI//CEII/PRIV" and "END CUI//CEII/PRIV".

12. [Reserved]

13. If either Party desires to include, utilize, or refer to Privileged Material or information derived from Privileged Material in testimony or other exhibits during the hearing in this proceeding in a manner that might require disclosure of such materials to persons other than Reviewing Representatives, that Party first must notify both counsel for the disclosing Party and any Presiding Judge, and identify all such Privileged Material. Thereafter, use of such Privileged Material will be governed by procedures determined by the Parties or, if applicable, the Presiding Judge.

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[9] *See infra* P 21.

[10] 82 Fed. Reg. 18632 (Apr. 20, 2017) (issued by Commission Apr. 14,2017).

14. Nothing in this Agreement shall be construed as precluding any Party from objecting to the production or use of Privileged Material and/or CEII on any appropriate ground.

15. Nothing in this Agreement shall preclude any Party from requesting a Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), the Commission, or any other body having appropriate authority, to find this Agreement should not apply to all or any materials previously designated Privileged Material pursuant to this Agreement. A Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), the Commission, or any other body having appropriate authority may alter or amend this Agreement as circumstances warrant at any time during the course of this proceeding.

16. Each Party governed by this Agreement has the right to seek changes in it as appropriate from a Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), the Commission, or any other body having appropriate authority.

17. Subject to Paragraph 18, a Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), or the Commission shall resolve any disputes arising under this Agreement pertaining to Privileged Material according to the following procedures. Prior to presenting any such dispute to a Presiding Judge, the Chief Judge, or the Commission, the Parties to the dispute shall employ good faith best efforts to resolve it.

A. Any Party that contests the designation of material as Privileged Material shall notify the Party that provided the Privileged Material by specifying in writing the material for which the designation is contested.

B. In any challenge to the designation of material as Privileged Material, the burden of proof shall be on the Party seeking protection. If a Presiding Judge, the Chief Judge, or the Commission finds that the material at issue is not entitled to the designation, the procedures of Paragraph 18 shall apply.

C. The procedures described above shall not apply to material designated by a Party as CEII. Material so designated shall remain subject to the provisions of this Agreement, unless a Party requests and obtains a determination from the Commission's CEII Coordinator that such material need not retain that designation.

18. The designator will have five (5) days in which to respond to any pleading filed with a Presiding Judge, the Chief Judge, or the Commission requesting disclosure of Privileged Material. Should such Presiding Judge, the Chief Judge, or the Commission, as appropriate, determine that the information should be made public, such Presiding Judge, the Chief Judge, or the Commission will provide notice to the designator no less than five (5) days prior to the date on which the material will become public. This Agreement shall automatically cease to apply to such material on the sixth (6th) calendar day after the notification is made unless the designator files a motion with such Presiding Judge, the Chief Judge, or the Commission, as appropriate, with supporting affidavits, demonstrating why the material should continue to be privileged. Should such a motion be filed, the material will remain confidential until such time as the

interlocutory appeal or certified question has been addressed by the Motions Commissioner or Commission, as provided in the Commission's regulations, 18 C.F.R. §§ 385.714, 385.715. No Party waives its rights to seek additional administrative or judicial remedies after a Presiding Judge or Chief Judge decision regarding Privileged Material or the Commission's denial of any appeal thereof or determination in response to any certified question. The provisions of 18 C.F.R. §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act (5 U.S.C. § 552) for Privileged Material and/or CEII in the files of the Commission.

19. Privileged Material and/or CEII shall remain available to Parties until the later of 1) the date an order terminating this proceeding no longer is subject to judicial review, or 2) the date any other Commission proceeding relating to the Privileged Material and/or CEII is concluded and no longer subject to judicial review. After this time, the Party that produced the Privileged Material and/or CEII may request (in writing) that all other Parties return or destroy the Privileged Material and/or CEII. This request must be satisfied with within fifteen (15) days of the date the request is made. However, copies of filings, official transcripts and exhibits in this proceeding containing Privileged Material, or Notes of Privileged Material, may be retained if they are maintained in accordance with Paragraph 5 of this Agreement. If requested, each Party also must submit to the Party making the request an affidavit stating that to the best of its knowledge it has satisfied the request to return or destroy the Privileged Material and/or CEII. To the extent Privileged Material and/or CEII are not returned or destroyed, they shall remain subject to this Agreement.

20. Nothing in this Agreement shall be deemed to preclude either Party from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Agreement. Neither Party waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Privileged Material and/or CEII.

IN WITNESS WHEREOF, the Parties each have caused this Agreement to be signed by their respective duly authorized representatives as of the date first set forth above.

By: ____________________________	By: ____________________________
Name: __________________________	Name: __________________________
Title: ___________________________	Title: ___________________________
Representing Applicant	Representing Intervenor

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Privileged Material and/or Critical Energy/Electric Infrastructure Information (CEII) is provided to me pursuant to the terms and restrictions of the Agreement dated _____________, 20__ by and between [Applicant] and [Intervenor] concerning materials in Federal Energy Regulatory Commission Docket No. ________ (the "Agreement"), that I have been given a copy of and have read the Agreement, and that I agree to be bound by it.

I understand that the contents of Privileged Material and/or CEII, any notes or other memoranda, or any other form of information that copies or discloses such materials, shall not be disclosed to anyone other than in accordance with the Agreement. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: ____________________________________

Printed Name: __________________________

Title: __________________________________

Representing: __________________________

Date: __________________________________