Rockland Electric Company

Joshua A. Konecni
Associate Counsel
Rockland Electric Company
4 Irving Place, Room 1815-S, New York, NY 10003
Tel.: 212-460-3593
Email: konecnij@coned.com

January 26, 2017

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

Re: Rockland Electric Company, Docket No. ER17-856-000

Dear Ms. Bose:

Pursuant to Sections 205 and 219 of the Federal Power Act,[1] Part 35 of the Commission's Regulations,[2] and Order No. 679,[3] Rockland Electric Company ("RECO") respectfully requests that the Commission approve: (1) the attached Tariff sheets updating RECO's stated annual transmission revenue requirement, transmission rates, and rate for Schedule 1A services;[4] (2) a new RECO base return on equity ("ROE") of 10.2 percent; and (3) a 50 basis point ROE adder for RECO's continued participation in PJM Interconnection L.L.C. ("PJM"), a Regional Transmission Organization ("RTO") ("RTO Participation Incentive").[5] RECO is thus seeking a new total ROE of 10.7 percent, which is less than its current ROE of 11.11 percent.

In support of this filing, RECO submits the testimony and associated exhibits of: (1) Francis Peverly, Vice President - Operations, Orange and Rockland Utilities, Inc. ("O&R"); (2) the accounting panel of John de la Bastide, Jack Deem, and Wenqi Wang, ("Accounting Panel"); and (3) Adrian McKenzie. RECO also submits the cost of service

[1] 16 U.S.C. §§ 824d and 824s (2012).

[2] 18 C.F.R. §35.13 (2016).

[3] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007) (Order No. 679).

[4] Schedule 1A covers Scheduling, System Control and Dispatch Service.

[5] Pursuant to Order No. 714, this filing is submitted by PJM on behalf of RECO 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, RECO has requested that PJM submit its proposed updated Tariff Sheets in the eTariff system as part of PJM's electronic Intra PJM Tariff.

statements and other information required by the Commission's regulations, to the extent applicable.

RECO respectfully requests that the Commission approve the updated Tariff sheets, ROE, and RTO Participation Incentive, without suspension or hearing, effective April 3, 2017. However, in the event that the Commission decides to set this case for hearing and settlement judge procedures, RECO respectfully requests that in its order on this filing the Commission: (1) approve RECO's request for a 50 basis point ROE adder for continued participation in PJM; and (2) confirm that the basic methodology RECO used to calculate its updated annual revenue requirement—which the Commission has previously approved—remains just and reasonable, and as such, is not an issue set for hearing or settlement.

I. BACKGROUND

A. Description of RECO and its Affiliates

RECO is an electric-only utility that provides transmission, retail distribution, and provider of last resort service to approximately 73,000 customers in northern New Jersey. As a New Jersey utility, RECO is subject to the retail jurisdiction of the New Jersey Board of Public Utilities. RECO's service territory includes parts of three counties that border New York—Bergen, Passaic, and Sussex— but the majority of its customers (more than 59,000) reside in Bergen County. RECO classifies its Bergen County service territory as its "Eastern Division," its Passaic County service territory as its "Central Division," and its Sussex County service territory as its "Western Division." As discussed below, RECO is a PJM transmission owner because it has turned over operational control of its Eastern Division transmission assets to PJM. RECO's Central and Western Divisions, which are not geographically contiguous to its PJM service area, along with O&R, are members of the New York Independent System Operator, Inc. ("NYISO"). In 2015, RECO's peak load for its Eastern Division was 396 MW.[6]

RECO is a wholly owned subsidiary of O&R,[7] which in turn is a wholly owned subsidiary of Consolidated Edison, Inc. ("CEI"), the parent company of Consolidated Edison Company of New York, Inc. ("Con Edison").[8] O&R is an electric and gas utility

[6] In the remainder of this letter, references to "RECO" are to RECO's Eastern Division, which is the Division in PJM.

[7] O&R also owned Pike County Light & Power Company, an electric and gas utility located in Pennsylvania until 2016.

[8] Con Edison is a regulated public utility that provides electric service in New York City and most of Westchester County, gas service in parts of New York City, and steam service within the borough of Manhattan. Con Edison serves approximately 3.3 million electric customers, 1.1 million gas customers, and 1,700 steam customers. Con Edison is a transmission owner in the NYISO's control area, a load serving entity, and a distribution provider in New York City and parts of Westchester County.

and a transmission owner in the NYISO's control area. O&R serves more than 225,000 electric customers and more than 130,000 gas customers in three New York counties: Rockland, Orange, and Sullivan. Two of these counties, Rockland and Orange, border RECO's service territory. In 2015, O&R's peak load was 1009 MW.

RECO has no operating employees; O&R provides all of RECO's administrative and operating services. Legal and other corporate services are provided to RECO by Con Edison. In addition, since the RECO and O&R transmission systems have historically been operated as a single system, O&R continues to design and operate them as a single integrated system ("Integrated Transmission System") from its control center in Spring Valley, New York. In 2015, the peak load of the Integrated Transmission System was 1405 MW.

B. RECO's Move to PJM And Approval of Current Rates

RECO joined PJM by transferring operational control of its Eastern Division transmission facilities from the NYISO to PJM in 2001 ("PJM Transfer"). RECO requested the PJM Transfer to facilitate its participation in New Jersey's restructuring of the retail market.[9] Before that, RECO did not have its own annual revenue requirement or transmission rates. Instead, its costs were factored into O&R's transmission revenue requirement which is a rate under the NYISO Tariff.

The Commission approved RECO's current annual revenue requirement and transmission rates at the same time it approved the PJM Transfer.[10] Because, as noted above, the RECO and O&R transmission systems are designed and operated as a single integrated system, RECO proposed to establish its annual revenue requirement in PJM by segregating and assigning costs to the PJM part of its load. RECO accomplished this by multiplying the annual revenue requirement for the Integrated Transmission System by the ratio of the RECO system peak load to the system peak load for the Integrated Transmission System:

> Rockland started with the overall O&R 1994 system-wide annual TRR of $32,820,759, which resulted from the settlement approved by the Commission in Docket No. OA96-210-000.[] In order to allocate an appropriate amount of transmission costs to the Rockland pricing zone, Rockland determined that the Rockland single system peak load in 1994 was 367 MW of the total 1994 O&R system-wide peak load of 1,022 MW. Using the ratio of 367/1022 and applying it to the overall O&R TRR, Rockland calculated a TRR for the Rockland pricing zone of

9 *Rockland Elec. Co,* 97 FERC ¶ 61,357 at P 9 (2001) ("RECO Order").

10 *Id.* P 9.

> $11,785,928. The resulting annual transmission rate is $32.114 per kW/year based on the prior Commission-approved TRR.[11]

The Commission approved RECO's proposed rates and proposed method without comment. [12]

C. Investment in the Integrated Transmission System

As explained by Company witness Peverly, and as set forth in Exhibit No. RECO-4, there has been significant investment in the Integrated Transmission System since 2001 that justifies RECO updating its transmission rates. For example, in 2003, RECO completed the South Mahwah-Upper Saddle River Project, which entailed replacement of approximately 0.70 miles of 69kV direct buried transmission cable between the South Mahwah and Upper Saddle River Substations in Bergen County with new cable in a manhole and duct system. Placing this project in service improved reliability for customers. In 2004, RECO completed construction of two new 138kV transmission line terminals for the underground cables required to feed its Darlington Substation. This project improved reliability and service to residential and commercial customers in Bergen County. In 2006, RECO completed the Closter to Cresskill Project, which included the upgrade of a double circuit 34.5kV wood pole transmission line to 69kV, as well as an upgrade of the Cresskill Substation. Construction of new double circuit transmission Lines 61 and 751 provided two 69kV transmission sources to the Cresskill Substation. In 2011, the Integrated Transmission System was enhanced by the Corporate Drive Project, which entailed construction of an underground extension to 138kV Lines 702 and 703 and the construction of an overhead to underground transition structure in Orangeburg, New York. Finally, in 2016, the Integrated Transmission System was enhanced by the addition of a 175 MVA 138-69kV autotransformer bank, Bank 167, at the Sterling Forest Substation in Tuxedo, New York. As explained by the Accounting Panel, this transmission investment is a significant reason why RECO needs to update its rates.

II. SUMMARY OF REQUESTED ACTIONS

A. Updated Rates

RECO has not updated its stated annual revenue requirement or transmission rates since 2001. In this filing, RECO seeks to update its rates as follows:

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[11] *See* Rockland Electric Company and PJM, Joint Filing For Approval of Transfer of Operational Control Over Jurisdictional Facilities And Acceptance for Filing of Tariff Revisions, Executed Signature Pages, and Membership Agreement Under Sections 203 and 205 of the Federal Power Act, Docket Nos. EC02-7- & ER02-109-000 at 30 (filed Oct. 17, 2001) (RECO-PJM Filing) (citation omitted).

[12] *RECO Order*, 97 FERC ¶ 61,357.

CATEGORY	CURRENT RATE	PROPOSED RATE	TARIFF SECTION
Annual Revenue Requirement	$11,785,928	$19,661,232	Attachment H-12
Annual Rate for Network Integration Transmission Service	$32,114 per MW per year	$49,695 per MW per year	Attachment H-12
Annual Transmission Rate for Firm Service	$32.114/kW[13]	$49.695/kW	Schedule 7
Schedule 1A Rate	$0.2475/MWh	$0.5351/MWh	Schedule 1A

B. Updated ROE

RECO requests a total updated ROE of 10.7 percent, which reflects a new base ROE of 10.2 percent and a request for a new 50 basis point ROE incentive for RTO participation with PJM. RECO's current ROE is 11.11 percent.

III. RECO'S FILING IS JUST AND REASONABLE

A. RECO's Updated Transmission Rates

RECO proposes to update its transmission rates using the same methodology that the Commission approved in 2001. Specifically, RECO derived its updated annual revenue requirement by: (1) calculating the 2015 annual revenue requirement for the Integrated Transmission System ($69,841,504);[14] and (2) multiplying it by the ratio of the 2015 RECO system peak load to the 2015 Integrated Transmission System peak load (395.64 MW/1,405.41 MW). Applying this calculation, RECO arrived at an updated annual revenue requirement of $19,661,232.40 and an updated annual transmission rate of $49,695 per MW/year.[15]

As explained in more detail in the Accounting Panel Testimony, RECO calculated the first part of this equation—the 2015 annual revenue requirement for the Integrated Transmission System—in four steps. First, RECO used 2015 FERC Form 1 data to identify the Integrated Transmission System's Total Transmission Plant balance. Second,

[13] The proposed updated rates for monthly, weekly, daily, and hourly point-to-point service are set forth in the revised Schedules 7 and 8 included in this filing.

[14] Neither RECO nor O&R are proposing to make any changes to O&R's annual revenue requirement in the NYISO Tariff.

[15] The updated annual revenue requirement and updated annual transmission rate for network service will be set forth in Attachment H-12 of the PJM Tariff, and the corresponding rates for monthly, weekly, daily, and hourly point-to-point transmission service will be set forth in Schedules 7 and 8 of the PJM Tariff. *See* Appendix A herein.

RECO calculated a composite fixed charge percent by using the following cost factors: (1) O&M, (2) Other Taxes, (3) A&G, (4) Return, (5) Depreciation, (6) Composite Income Tax, (7) General Plant/Common Plant, (8) Cash Working Capital, and (9) Accumulated Deferred Income Tax Adjustment. Third, RECO multiplied the Total Transmission Plant balance by the fixed charge rate to arrive at the annual revenue requirement before line losses for the Integrated Transmission System. Fourth, RECO adjusted for line loss revenue (3.7 percent) to arrive at the updated revenue requirement for the Integrated Transmission System.

RECO's updated rates are just and reasonable because they: (1) are derived from a methodology the Commission has already approved; (2) rely on FERC Form 1 data; and, (3) as explained in the Accounting Panel Testimony, reflect a composite fixed charge rate composed of reasonable factors derived from reasonable calculations.

B. RECO's Updated Schedule 1A Rate

RECO is also seeking to update its Schedule 1A rate from $0.2475 per megawatt hour to $0.5351 per megawatt hour. As explained in the Accounting Panel Testimony, RECO calculated its updated Schedule 1A rate by: (1) calculating the total O&R Scheduling System Control and Dispatch Revenue Requirement; and (2) dividing it by the combined system's billing units (or total customer megawatt sales less sales for resale to other utilities). The new RECO PJM zone revenue requirement for Scheduling System Control and Dispatch of $786,001 was calculated by multiplying this rate by the RECO PJM zone billing units of 1,468,886 megawatt hours.

Historically, RECO's Schedule 1A rate was calculated using a PJM Non-Zone Adjustment Factor of 0.9441425 to account for the rate's application to the PJM portion of RECO's service territory. This adjustment factor was based on the portion of peak day RECO load that was in the PJM zone. In this filing, RECO does not propose to use a PJM Non-Zone Adjustment Factor because the updated Schedule 1A rate was calculated using the megawatt hours specific to the RECO PJM zone, making a Non-Zone Adjustment Factor unnecessary.

C. RECO's Updated ROE

i. Base ROE

RECO proposes a new base ROE of 10.2 percent based on the recommendation of Mr. Adrien McKenzie. Mr. McKenzie performed a two-step Discounted Cash Flow ("DCF") analysis that is consistent with the Commission's latest guidance in Opinion No. 531.[16] Overall, a number of factors support the conclusion that the base ROE of 10.2

[16] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234, *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), *appeals docketed sub nom. Emera Maine v. FERC*, Nos. 15-1118, *et al.* (D.C. Cir. Apr. 30, 2015).;

percent is just and reasonable. First, the base ROE is within the zone of reasonableness when applying the two-step DCF model and using Institutional Brokers Estimate System ("IBES") based data. Second, as the Commission recognized in Order No. 531, the results of the two-step DCF model do not fully account for current capital market conditions. Accordingly, in order to ensure that RECO's base ROE is just and reasonable, Mr. McKenzie "consider[ed] the results of other ROE models and benchmarks, which are widely employed in regulatory proceedings and utilized in the financial community."[17] Mr. McKenzie used other specific Commission-approved benchmarks that are recognized in Opinion Nos. 531 and 551[18] to justify his resultant base ROE, which appropriately falls within the upper ranges of the collective zones of reasonableness. These additional benchmarks include a risk premium analysis, a capital asset pricing model analysis, and an expected earnings analysis.

Moreover, Mr. McKenzie expanded the proxy group to include utilities rated one notch below RECO's A-/A3 credit rating in order to achieve a group of sufficient size, consistent with the Commission's "comparable risk band" approach approved in prior proceedings.[19] As Mr. McKenzie explains, this adaptation provides an appropriate proxy group because the utilities included represent the highest-rated and most risk-comparable utilities to RECO. Mr. McKenzie concludes that RECO's requested total ROE of 10.7 percent (including the 50 basis point RTO Participation Incentive) is sufficient to support RECO's need to attract capital and earn a competitive return.

ii. RTO Participation Incentive

Consistent with section 219(c) of the Federal Power Act, Order No. 679, and Commission precedent, RECO requests a 50 basis point adder to its base ROE for its continued participation in PJM, a Commission approved RTO.

The Commission determined in Order No. 679 that it will approve ROE incentives "for public utilities that join and/or continue to be a member of an [independent system operator ("ISO")], RTO, or other Commission-approved

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Coakley, Mass. Atty. Gen. v. Bangor Hydro-Elec. Co., Opinion No. 531, 147 FERC ¶ 61,234, order on paper hearing, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015).

[17] Exhibit No. RECO-5 at 5.

[18] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 (2016), *reh'g pending*.

[19] *See, e.g.*, *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 53 (2010), *pet. for review granted in part and denied in part*, 717 F.3d 177 (D.C. Cir. 2013); *Tallgrass Transmission LLC*, 125 FERC ¶ 61,248 at P 77 (2008), *reh'g denied*, 150 FERC ¶ 61,224 (2015).

Transmission Organization."[20] The Commission has found that this incentive recognizes the benefits that flow from RTO/ISO membership, and that a "utility is presumed eligible for an RTO incentive 'if it can demonstrate that it has joined an RTO, ISO, or other Commission-approved Transmission Organization, and that its membership is on-going' and need not provide additional justification as to the necessity or benefits of the incentive."[21] The Commission has thus emphasized 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."[22] Accordingly, the Commission has routinely approved the RTO Participation Incentive as long as the resultant ROE after application of the RTO Participation Incentive is within the ROE zone of reasonableness.[23]

As described above, RECO is a member of PJM and has turned over operational control of its transmission facilities to PJM and will do the same for any future transmission projects. RECO's requested total ROE of 10.7 percent is within the upper end of the zone of reasonableness determined using the IBES-based DCF zone of reasonableness analysis.

IV. <u>REQUIRED INFORMATION AND CONTENTS OF FILING</u>

Pursuant to Section 35.13(a)(1) of the Commission's regulations, RECO provides the following information:

[20] Order No. 679 at P 326 (emphasis added); 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) ("Tariff Equity Coal.") ("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.").

[21] *New York Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,004 ("NY Transco Order") at P 90 (quoting Order No. 679 at P 327); *see also Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,004 at PP 41-44 (2015); *Pacific Gas & Elec. Co.*, 141 FERC ¶ 61,168 at P 25 (2012) (determining that granting incentive ROE for "participation in the CAISO is consistent with the stated purpose of FPA section 219 . . . and is intended to encourage [transmission owner's] continued involvement in the CAISO," despite arguments that such incentive is no longer necessary) (footnotes omitted); *Niagara Mohawk Power Corp.*, 124 FERC ¶ 61,106 at P 35 (2008) (We will grant up to 50 basis points of incentive ROE for Niagara Mohawk's continued participation in NYISO . . . . Our decision to grant Niagara Mohawk an incentive for participation in the NYISO is consistent with the stated purpose of section 219 of the FPA—that the incentive applies to all utilities joining the transmission organization— and is intended to encourage Niagara Mohawk's continued involvement with NYISO.") (footnotes omitted).

[22] *Tariff Equity Coal.*, 149 FERC ¶ 61,049 at P 200.

[23] *See id.*; *see also* NY Transco Order at P 91.

A. Information Required by § 35.13(b)

i. List of Documents Submitted (18 C.F.R. § 35.13(b)(1))

In addition to this filing letter, this filing consists of:

Appendix A: Red-lined Tariff Sheets

Appendix B: Clean Tariff Sheets

Appendix C: Direct Accounting Panel Testimony and Exhibits of John de la Bastide, Jack Deem, and Wenqi Wang (Exhibit Nos. RECO-1 and RECO 2)

Appendix D: Direct Testimony and Exhibits of Francis Peverly (Exhibit Nos. RECO-3 and RECO 4)

Appendix E: Direct Testimony and Exhibits of Adrian McKenzie (Exhibit Nos. RECO-5 through RECO-17)

Appendix F: Attestation required by 18 C.F.R. §35.13(d)(6)

Appendix G: Period I and Period II Cost of Service Statements and Schedules

ii. Proposed Effective Date (18 C.F.R. § 35.13(b)(2))

RECO proposes an effective date of April 3, 2017.

iii. Persons Receiving Notice (18 C.F.R. § 35.13(b)(3))

See Section VII herein.

iv. Brief Description of Rate Change (18 C.F.R. § 35.13(b)(4))

See Sections II and III herein.

v. Reasons for Rate Change (18 C.F.R. § 35.13(b)(5))

See Sections II and III herein, and Exhibit Nos. RECO-1 through RECO 4 (Accounting Panel and Peverly Testimonies and associated Exhibits)

vi. Agreement to Rate Change (18 C.F.R. § 35.13(b)(6))

Not applicable.

vii. Statement as to Expenses or Costs (18 C.F.R. § 35.13(b)(7))

No RECO expenses or costs that have been used to support RECO's proposed rates "have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices."[24]

B. Additional Information Required by § 35.13(b)

i. Information Relating to the Effect of the Rate Change (18 C.F.R. § 35.13(c))

Information relating to the effect of the rate change is provided in the testimony of the Accounting Panel and associated Exhibit. See Exhibit Nos. RECO-1 and RECO 2.

ii. Cost of Service Information (18 C.F.R. §§ 35.13(d), (e)(1)(i), & (h))

See Appendix F.

iii. Testimony and Exhibits (18 C.F.R. §§ 35.13(e)(1)(ii) & (e)(2))

Testimony supporting RECO's updated rate is provided by (1) the Accounting Panel and (2) Francis Peverly. Testimony supporting RECO's updated ROE is provided by Adrian McKenzie. In the event that this matter is set for hearing, the material submitted as part of this filing shall comprise RECO's case in chief, subject to the Presiding Judge permitting the submission of amended or additional materials.

V. REQUEST FOR WAIVERS

RECO requests that the Commission waive the requirements of 18 C.F.R. § 35.13 to the extent necessary to accept this filing. Several of the cost of service statements required by section 35.13 are not applicable to RECO. In addition, with respect to Statements BB, BD, and BE, RECO requests waiver to the extent that RECO's response does not include information not applicable to RECO. Finally, RECO requests a waiver

[24] 18 C.F.R. § 35.13(b)(7).

of any other Commission rule or regulation as may be necessary to permit the proposed Tariff revisions to be accepted by the Commission and made effective as requested.

VI. EFFECTIVE DATE

RECO requests that its updated rates and ROE become effective, without hearing or suspension, on April 3, 2017, which is more than 60 days from the date of filing. In the event that the Commission sets RECO's filing for hearing, however, RECO respectfully requests that the Commission: (1) approve in its order RECO's request for a 50 basis point ROE adder for RTO participation; and (2) confirm in its order that the basic methodology RECO used to calculate its updated annual revenue requirement—multiplying the updated annual revenue requirement for the Integrated Transmission System by the updated ratio of the RECO system peak load to the Integrated Transmission System peak load—remains acceptable, and as such, is not an issue set for hearing.

VII. SERVICE

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,[25] 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[26] 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 document 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.

VIII. CORRESPONDENCE AND COMMUNICATIONS

RECO requests that all correspondence and communications with respect to this filing be sent to, and the Secretary include on the official service list, the following persons:

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

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

Francis W. Peverly
Vice President, Operations
Orange and Rockland Utilities, Inc.
390 West Route 59
Spring Valley, NY 10977
(845)-577-3697
peverlyf@oru.com

Joshua A. Konecni
Kyle J. Hayes
Law Department
Consolidated Edison
Company of New York, Inc.
(212) 460-3593
konecnij@coned.com
hayesk@coned.com

IX. CONCLUSION

For the reasons discussed above and in the attached testimony, RECO respectfully requests that the Commission approve RECO's updated rates, ROE, and RTO Participation Incentive, effective April 3, 2017.

Dated: January 26, 2017
New York, New York

Respectfully submitted,

ROCKLAND ELECTRIC COMPANY

/s/ Joshua A. Konecni
Joshua A. Konecni
Associate Counsel
Kyle J. Hayes
Senior Attorney
Rockland Electric Company
4 Irving Place, Room 1815-S
New York, N.Y. 10003
Phone: 212-460-3593
konecnij@coned.com
hayesk@coned.com

/s/ Francis W. Peverly
Francis W. Peverly
Vice President, Operations
Rockland Electric Company
390 West Route 59
Spring Valley, New York 10977
Phone (845) 577-3697
Fax (718) 923-7011
Email: peverlyf@oru.com

Appendix A

Redlined Tariff Sheets

SCHEDULE 1A
Transmission Owner Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

Zone	Rate ($/MWh)
Atlantic City Electric Company	0.0781
Baltimore Gas and Electric Company	0.0430
Delmarva Power & Light Company	0.0743
PECO Energy Company	0.1189
PP&L, Inc. Group	0.0618
Potomac Electric Power Company	0.0186
Public Service Electric and Gas Company	0.1030
Jersey Central Power & Light Company	*Rate updated annually Per Attachment H-4*
Metropolitan Edison Company	*Rate updated annually Per Attachment H-28*
Pennsylvania Electric Company	*Rate updated annually Per Attachment H-28*
Rockland Electric Company	~~0.2475~~0.5351
Commonwealth Edison Company	0.2223
AEP East Operating Companies	Rate updated annually Per Attachment H-14
The Dayton Power and Light Company[1]	0.0797
Duquesne Light Company	0.0520
American Transmission Systems, Incorporated ("ATSI")	Rate updated annually Per Attachment H-21

[1] Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	Rate updated annually Per Attachment H-22
East Kentucky Power Cooperative, Inc. ("EKPC")	Per Attachment H-24

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region):

$.0912//MWh

Each month, PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

Transmission Owner	**Share (%)**
Atlantic City Electric Company	1.41
Baltimore Gas and Electric Company	2.28
Delmarva Power & Light Company	2.17
PECO Energy Company	7.57
PP&L, Inc. Group	3.88
Potomac Electric Power Company	0.92
Public Service Electric and Gas Company	7.55
Jersey Central Power & Light Company	3.71
Mid-Atlantic Interstate Transmission, LLC	*3.12*
Rockland Electric Company	0.57
Commonwealth Edison Company	41.42
AEP East Operating Companies	14.56
The Dayton Power and Light Company	2.41
Duquesne Light Company	1.20
American Transmission Systems, Incorporated ("ATSI")	3.05
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	4.17[2]
East Kentucky Power Cooperative, Inc. ("EKPC")	0.0

[2] Any change to this share must be made as a tariff filing under Section 205 of the Federal Power Act.

SCHEDULE 7
Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	**Yearly Charge**	**Monthly Charge**	**Weekly Charge**	**Daily On-Peak[1] Charge**	**Daily Off-Peak[2/] Charge**
Border of PJM	18.888	1.574	0.3632	0.0726	0.0519
AE Zone	23.809	1.984	0.4580	0.0920	0.0650
BG&E Zone	15.675	1.306	0.3010	0.0600	0.0430
Delmarva Zone	19.378	1.615	0.3730	0.0750	0.0530
JCPL Zone	15.112	1.259	0.2906	0.0581	0.0414
MetEd Zone	15.112	1.259	0.2906	0.0581	0.0414
Penelec Zone	15.112	1.259	0.2906	0.0581	0.0414
PECO Zone	26.264	2.189	0.5051	0.1010	0.0722
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.463 UGI: *	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *
Pepco Zone	20.999	1.750	0.4040	0.0810	0.0580
PSE&G Zone	23.696	1.975	0.4557	0.0911	0.0651
AP Zone	20.847	1.737	0.4009	0.0802	0.0573
Rockland Zone	49.695 ~~32.114~~	4.141 ~~2.676~~	0.9557 ~~0.6176~~	0.1911 ~~0.1235~~	0.1365 ~~0.0882~~

ComEd Zone[3/]	[4/]				

* PPL Electric Utilities Corporation’s and UGI Utilities’ respective component of the total charge is posted on the PJM Internet website.

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
AEP East Zone[5/]	Monthly Charge X 12	Rate Pursuant to Attachment H-14	Yearly Charge / 52	Weekly Charge / 5	Weekly Charge / 7
Dayton Zone	15.674	1.306	0.3014	0.0603	0.0431
Duquesne Zone	14.17	1.18	0.27	0.0540	0.0386
Dominion Zone[6/]					
ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22
EKPC Zone	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

1/ Monday – Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ Each month, revenue credits will be applied to the gross charge in accordance with section 8 below to determine the actual charge to the Transmission Customer.

4/ The charges for the ComEd zone are posted on PJM's website. In addition to other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

5/ The rates for firm point-to-point transmission service in the AEP Zone will be charged at the yearly, monthly, weekly or daily rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

6/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Yearly Charge - $/kW/year = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 1000 kW/MW

Monthly Charge - $/kW/month. = Yearly Charge divided by 12;

Weekly Charge - $/kW/week = Yearly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7.

On a monthly basis, revenue credits shall be calculated based on the sum of VEPCO's share of revenues collected during the month from Schedule 7 and Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A. The sum of these revenue credits will appear as an adjustment to the to the gross monthly service period charges produced by the above formula.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery, or Daily Off-Peak Delivery shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion, Losses and Capacity Export:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, shall pay any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse PJMSettlement for any amounts payable as 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.

6) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in section (1) of this schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the PJM Region a non-discountable charge of $3.60/kw/year, $0.30/kw/mo., $0.0692/kw/week, $0.0099/kw/day-off-peak, or $0.0138/kw/day-on-peak. PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (6) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 8, and the Transitional Market Expansion Charge under Schedule 11 equal $84,993,360.

7) **Transmission Enhancement Charges.** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 8
Non-Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges

Point of Delivery	Monthly Charge ($/kW)	Weekly Charge ($/kW)	Daily On-Peak[1/] Charge ($/kW)	Daily Off-Peak[2/] Charge ($/kW)	Hourly On-Peak[3/] Charge ($/MWh)	Hourly Off-Peak[4/] Charge ($/MWh)
Border of PJM	1.574	0.3632	0.0726	0.0519	4.54	2.16
AE Zone	1.984	0.4580	0.0920	0.0650	5.7	2.72
BG&E Zone	1.306	0.3010	0.0600	0.0430	3.8	1.80
Delmarva Zone	1.615	0.3730	0.0750	0.0530	4.6	2.21
JCPL Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
MetEd Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
Penelec Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
PECO Zone	2.189	0.5051	0.1010	0.0722	6.3	3.01
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *	PPL: * AEC: 0.11 UGI: *	PPL: * AEC: 0.05 UGI: *
Pepco Zone	1.750	0.4040	0.0810	0.0580	5.0	2.40
PSE&G Zone	1.975	0.4557	0.0911	0.0651	5.7	2.71
AP Zone	1.737	0.4009	0.0802	0.0573	5.0	2.39
Rockland Zone	4.141 ~~2.676~~	0.9557 ~~0.6176~~	0.1911 ~~0.1235~~	0.1365 ~~0.0882~~	11.9 ~~7.7~~	5.69 ~~3.67~~
ComEd Zone[5/]	[6/]					

* PPL Electric Utilities Corporation's and UGI Utilities' respective component of the total charge is posted on the PJM Internet website.

AEP East Zone[7/] Nov. 1, 2005 SECA Ended W-JF Line In	AEP East Zone[7/]	Rate Pursuant to Attachment H-14	Monthly Charge X 12 / 52 ~~0.249 48~~	Weekly Charge / 5	Weekly Charge / 7	Daily On-Peak Charge / 16
Dayton Zone	Dayton Zone	1.306	0.3014	0.060 3	0.0431	3.77
Duquesne Zone	Duquesne Zone	1.18	0.27	0.054 0	0.0386	3.38
Dominion Zone[8/]	Dominion Zone[8/]					
ATSI Zone	ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22
EKPC Zone	EKPC Zone	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24

1/ Monday - Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ 7:00 a.m. up to the hour ending 11:00 p.m.

4/ 11:00 p.m. up to the hour ending 7:00 a.m.

5/ Each month, revenue credits will be applied to the gross charge in accordance with Paragraph 9 below to determine the actual charge to the Transmission Customer.

6/ The charges for the ComEd zone are posted on PJM's website. In addition to the other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:
Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;
Monthly Rate - $/kW/month. = Annual Rate divided by 12;
Weekly Rate - $/kW/week = Annual Rate divided by 52;
Daily rate - $/kW/day = Weekly Rate divided by 5.
In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be

needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

7/ The rates for non-firm point-to-point transmission service in the AEP Zone will be charged at the monthly, weekly, daily or hourly rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount, ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 8 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

8/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Monthly Charge - $/kW/month = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 12 divided by 1000 kW/MW;

Weekly Charge - $/kW/week = 12 times Monthly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7;

Hourly On-Peak Charge - $/MWh = Daily On-Peak Charge / 16 hours *1000 kW/ MW;

Hourly Off-Peak Charge - $/ MWh = Daily Off-Peak Charge / 24 hours *1000 kW/ MW.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery or Daily Off-Peak Delivery, shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the amounts set forth above for a Point of Delivery.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (1) above for daily service times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

4) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

5) **Congestion, Losses and Capacity Export:** A Transmission Customer desiring Non-Firm Point-to-Point Transmission Service may elect to pay transmission congestion charges. If the Transmission Customer so elects, it shall either (a) if the applicable Transmission Congestion Charge as calculated pursuant to Attachment K is positive, pay the higher of the applicable Transmission Congestion Charge or the applicable rate under section (1) above, or (b) if the

applicable Transmission Congestion Charge as calculated pursuant to Attachment K is negative, pay or be credited the sum of the applicable Transmission Congestion Charge and the rate under section (1) above. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, shall pay for any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

6) **Other Supporting Facilities and Taxes:** In addition to the charges set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as 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.

7) **Transmission Enhancement Charges:** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

ATTACHMENT H-12

Annual Transmission Rates -- Rockland Electric Company for Network Integration Transmission Service

1. The annual transmission revenue requirement is $~~11,785,928~~19,661,232 and the rate for Network Integration Transmission Service is $~~32,114~~49,695 per megawatt per year.

2. The rate stated in section 1 above shall be effective until amended by the Regional Transmission Owner(s) within the Zone or modified by the Commission.

3. In addition to the rate set forth in section 1 above, the 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 the Regional Transmission Owners for any amounts payable by them as 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.

Appendix B

Clean Tariff Sheets

SCHEDULE 1A
Transmission Owner Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service is provided directly by the Transmission Provider under Schedule 1. The Transmission Customer must purchase this service from the Transmission Provider. Certain control center facilities of the Transmission Owners also are required to provide this service. This Schedule 1A sets forth the charges for Scheduling, System Control and Dispatch Service based on the cost of operating the control centers of the Transmission Owners. The Transmission Provider shall administer the provision of Transmission Owner Scheduling, System Control and Dispatch Service. PJMSettlement shall be the Counterparty to the purchases of Transmission Owner Scheduling, System Control and Dispatch Service.

The charges for operation of the control centers of the Transmission Owners shall be determined by multiplying the applicable rate as follows times the Transmission Customer's use of the Transmission System (including losses) on a megawatt hour basis:

(A) For a Transmission Customer serving Zone Load in:

<u>Zone</u>	<u>Rate ($/MWh)</u>
Atlantic City Electric Company	0.0781
Baltimore Gas and Electric Company	0.0430
Delmarva Power & Light Company	0.0743
PECO Energy Company	0.1189
PP&L, Inc. Group	0.0618
Potomac Electric Power Company	0.0186
Public Service Electric and Gas Company	0.1030
Jersey Central Power & Light Company	*Rate updated annually Per Attachment H-4*
Metropolitan Edison Company	*Rate updated annually Per Attachment H-28*
Pennsylvania Electric Company	*Rate updated annually Per Attachment H-28*
Rockland Electric Company	0.5351
Commonwealth Edison Company	0.2223
AEP East Operating Companies	Rate updated annually Per Attachment H-14
The Dayton Power and Light Company[1]	0.0797
Duquesne Light Company	0.0520
American Transmission Systems, Incorporated ("ATSI")	Rate updated annually Per Attachment H-21

1 Charges for service under this schedule to customers of The Dayton Power and Light Company that are subject to the provisions of the October 14, 2003 Stipulation and Agreement of Settlement approved in FERC Docket No. EL03-56-000 shall be governed by such settlement.

Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	Rate updated annually Per Attachment H-22
East Kentucky Power Cooperative, Inc. ("EKPC")	Per Attachment H-24

(B) For a Transmission Customer serving Non-Zone Load (a Network Customer serving Non-Zone Network Load or a Transmission Customer taking Point-to-Point service where the Point of Delivery is at the boundary of the PJM Region):

$.0912//MWh

Each month, PJMSettlement shall pay to each Transmission Owner an amount equal to the charges billed for that Transmission Owner's zone pursuant to (A) above, plus that Transmission Owner's share as stated below of the charges billed to Transmission Customers serving Non-Zone Network Load pursuant to (B) above:

Transmission Owner	**Share (%)**
Atlantic City Electric Company	1.41
Baltimore Gas and Electric Company	2.28
Delmarva Power & Light Company	2.17
PECO Energy Company	7.57
PP&L, Inc. Group	3.88
Potomac Electric Power Company	0.92
Public Service Electric and Gas Company	7.55
Jersey Central Power & Light Company	3.71
Mid-Atlantic Interstate Transmission, LLC	*3.12*
Rockland Electric Company	0.57
Commonwealth Edison Company	41.42
AEP East Operating Companies	14.56
The Dayton Power and Light Company	2.41
Duquesne Light Company	1.20
American Transmission Systems, Incorporated ("ATSI")	3.05
Duke Energy Ohio, Inc., and Duke Energy Kentucky, Inc. ("DEOK")	4.17[2]
East Kentucky Power Cooperative, Inc. ("EKPC")	0.0

[2] Any change to this share must be made as a tariff filing under Section 205 of the Federal Power Act.

SCHEDULE 7
Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay each month for Reserved Capacity at the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges
(in $/kW)

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak [1] Charge	Daily Off-Peak[2/] Charge
Border of PJM	18.888	1.574	0.3632	0.0726	0.0519
AE Zone	23.809	1.984	0.4580	0.0920	0.0650
BG&E Zone	15.675	1.306	0.3010	0.0600	0.0430
Delmarva Zone	19.378	1.615	0.3730	0.0750	0.0530
JCPL Zone	15.112	1.259	0.2906	0.0581	0.0414
MetEd Zone	15.112	1.259	0.2906	0.0581	0.0414
Penelec Zone	15.112	1.259	0.2906	0.0581	0.0414
PECO Zone	26.264	2.189	0.5051	0.1010	0.0722
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.463 UGI: *	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *
Pepco Zone	20.999	1.750	0.4040	0.0810	0.0580
PSE&G Zone	23.696	1.975	0.4557	0.0911	0.0651
AP Zone	20.847	1.737	0.4009	0.0802	0.0573
Rockland Zone	49.695	4.141	0.9557	0.1911	0.1365

ComEd Zone[3/]	[4/]				

* PPL Electric Utilities Corporation’s and UGI Utilities’ respective component of the total charge is posted on the PJM Internet website.

Point of Delivery	Yearly Charge	Monthly Charge	Weekly Charge	Daily On-Peak[1] Charge	Daily Off-Peak[2/] Charge
AEP East Zone[5/]	Monthly Charge X 12	Rate Pursuant to Attachment H-14	Yearly Charge / 52	Weekly Charge / 5	Weekly Charge / 7
Dayton Zone	15.674	1.306	0.3014	0.0603	0.0431
Duquesne Zone	14.17	1.18	0.27	0.0540	0.0386
Dominion Zone[6/]					
ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22
EKPC Zone	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

1/ Monday – Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ Each month, revenue credits will be applied to the gross charge in accordance with section 8 below to determine the actual charge to the Transmission Customer.

4/ The charges for the ComEd zone are posted on PJM's website. In addition to other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

5/ The rates for firm point-to-point transmission service in the AEP Zone will be charged at the yearly, monthly, weekly or daily rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

6/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Yearly Charge - $/kW/year = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 1000 kW/MW

Monthly Charge - $/kW/month. = Yearly Charge divided by 12;

Weekly Charge - $/kW/week = Yearly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7.

On a monthly basis, revenue credits shall be calculated based on the sum of VEPCO's share of revenues collected during the month from Schedule 7 and Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A. The sum of these revenue credits will appear as an adjustment to the to the gross monthly service period charges produced by the above formula.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery, or Daily Off-Peak Delivery shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

4) **Congestion, Losses and Capacity Export:** In addition to any payment under this Schedule, the Transmission Customer shall pay Redispatch Costs as specified in Section 27 of the Tariff. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, shall pay any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

5) **Other Supporting Facilities and Taxes:** In addition to the rates set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse PJMSettlement for any amounts payable as 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.

6) **Transitional Revenue Neutrality Charge:** In addition to the rates set forth in section (1) of this schedule and any other applicable charges, the Transmission Customer shall also pay for Reserved Capacity for delivery at the border of the PJM Region a non-discountable charge of \$3.60/kw/year, \$0.30/kw/mo., \$0.0692/kw/week, \$0.0099/kw/day-off-peak, or \$0.0138/kw/day-on-peak. PJM shall distribute all revenues from the Transitional Revenue Neutrality Charge to Allegheny Power. The charge provided for under this section (6) shall terminate effective as of the day on which the sum total of the revenues collected by this charge, the Transitional Revenue Neutrality Charge under Schedule 8, and the Transitional Market Expansion Charge under Schedule 11 equal \$84,993,360.

7) **Transmission Enhancement Charges.** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEP's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

10) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 8
Non-Firm Point-To-Point Transmission Service

1) The Transmission Customer shall pay for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below for the Point of Delivery:

Summary of Charges

Point of Delivery	Monthly Charge ($/kW)	Weekly Charge ($/kW)	Daily On-Peak[1/] Charge ($/kW)	Daily Off-Peak[2/] Charge ($/kW)	Hourly On-Peak[3/] Charge ($/MWh)	Hourly Off-Peak[4/] Charge ($/MWh)
Border of PJM	1.574	0.3632	0.0726	0.0519	4.54	2.16
AE Zone	1.984	0.4580	0.0920	0.0650	5.7	2.72
BG&E Zone	1.306	0.3010	0.0600	0.0430	3.8	1.80
Delmarva Zone	1.615	0.3730	0.0750	0.0530	4.6	2.21
JCPL Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
MetEd Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
Penelec Zone	1.259	0.2906	0.0581	0.0414	3.6	1.73
PECO Zone	2.189	0.5051	0.1010	0.0722	6.3	3.01
PPL Zone: Total charge is the sum of the components	PPL: * AEC: 0.039 UGI: *	PPL: * AEC: 0.0089 UGI: *	PPL: * AEC: 0.0018 UGI: *	PPL: * AEC: 0.0013 UGI: *	PPL: * AEC: 0.11 UGI: *	PPL: * AEC: 0.05 UGI: *
Pepco Zone	1.750	0.4040	0.0810	0.0580	5.0	2.40
PSE&G Zone	1.975	0.4557	0.0911	0.0651	5.7	2.71
AP Zone	1.737	0.4009	0.0802	0.0573	5.0	2.39
Rockland Zone	4.141	0.9557	0.1911	0.1365	11.9	5.69
ComEd Zone[5/]	[6/]					

* PPL Electric Utilities Corporation's and UGI Utilities' respective component of the total charge is posted on the PJM Internet website.

AEP East Zone[7/] Nov. 1, 2005 SECA Ended W-JF Line In	AEP East Zone[7/]	Rate Pursuant to Attachment H-14	Monthly Charge X 12 / 52 ~~0.249 48~~	Weekly Charge / 5	Weekly Charge / 7	Daily On-Peak Charge / 16
Dayton Zone	Dayton Zone	1.306	0.3014	0.060 3	0.0431	3.77
Duquesne Zone	Duquesne Zone	1.18	0.27	0.054 0	0.0386	3.38
Dominion Zone[8/]	Dominion Zone[8/]					
ATSI Zone	ATSI Zone	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21	Rate Pursuant to Attachment H-21
DEOK Zone	DEOK Zone	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22	Rate Pursuant to Attachment H-22
EKPC Zone	EKPC Zone	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24	Rate Pursuant to Attachment H-24

1/ Monday - Friday except the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

2/ Saturday and Sunday and the following holidays: New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

3/ 7:00 a.m. up to the hour ending 11:00 p.m.

4/ 11:00 p.m. up to the hour ending 7:00 a.m.

5/ Each month, revenue credits will be applied to the gross charge in accordance with Paragraph 9 below to determine the actual charge to the Transmission Customer.

6/ The charges for the ComEd zone are posted on PJM's website. In addition to the other rates set forth in this schedule, customers within the ComEd zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:
Annual Rate - $/kW/year = $1,523,039, divided by the 1 CP demand for the ComEd zone for the prior calendar year;
Monthly Rate - $/kW/month. = Annual Rate divided by 12;
Weekly Rate - $/kW/week = Annual Rate divided by 52;
Daily rate - $/kW/day = Weekly Rate divided by 5.
In order to ensure that the charge does not result in either an over-recovery or under-recovery of ComEd's start-up costs, PJM will institute an annual true-up mechanism in the month of May of each of the years 2008-2014. In May of each of those years, PJM will compare the amount collected under this charge for the previous 12 months with the target annual amount of $1,523,039 and calculate any credits or surcharges that would be

needed to ensure that $1,523,039 is collected for each year. Any credit or surcharge will be assessed in the June bills for years 2008-2014, consistent with the above methodology.

7/ The rates for non-firm point-to-point transmission service in the AEP Zone will be charged at the monthly, weekly, daily or hourly rate equivalent to the rate effective in such period under Attachment H-14. In addition to other rates set forth in this schedule, customers within the AEP East Zone shall be charged for recovery of RTO start-up costs at the following rates, each computed to four decimal places:

Annual Rate - $/kW/year = $2,362,185, plus any applicable true-up adjustment, divided by the 1 CP demand for the AEP East Zone for the prior calendar year;

Monthly Rate - $/kW/month. = Annual Rate divided by 12;

Weekly Rate - $/kW/week = Annual Rate divided by 52;

Daily Rate - $/kW/day = Weekly Rate divided by 5.

For the period November 1, 2005 through March 31, 2006, the rate shall be $8.94/MW-month; for the period April 1 through December 31, 2006, the rate shall be $8.60/MW-month, thereafter, the rate will be subject to the following true-up:

In order to ensure that the charge does not result in either over-recovery or under-recovery of AEP's start-up costs, PJM will institute an annual true-up mechanism and implement revised charges as of January 1st of each of the years 2007-2019. In January of each of those years, PJM will compare the amount collected under this charge for the previous year or part thereof with the target annual amount of $2,362,185 and calculate the rates that would be needed, given the expected billing demands, to collect $2,362,185, adjusted for any prior year over-collection or under-collection. In the final year that the rate is collected, PJM will calculate the rate to collect five-twelfths of the annual amount, ($984,244), plus or minus any prior year true up amount, by May 31 of that year, and shall charge such rate until that amount is collected, whether that date be before or after May 31, 2020.

Effective December 1, 2004, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 8 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc. obtained pursuant to requests submitted on or after November 17, 2003, for service commencing on or after April 1, 2004. Effective April 1, 2006, the charge for Points of Delivery at the Border of PJM and the Transitional Revenue Neutrality Charge under this Schedule 7 shall not apply to any Reserved Capacity with a Point of Delivery of the Midwest Independent Transmission System Operator, Inc.

8/ The service period charges rounded to four decimal places for the Dominion Zone are as follows:

Monthly Charge - $/kW/month = the formula rate for Network Integration Transmission Service as described in Attachment H-16 and Attachment H-16A divided by 12 divided by 1000 kW/MW;

Weekly Charge - $/kW/week = 12 times Monthly Charge divided by 52;

Daily On-Peak Charge - $/kW/day = Weekly Charge divided by 5;

Daily Off-Peak Charge - $/kW/day = Weekly Charge divided by 7;

Hourly On-Peak Charge - $/MWh = Daily On-Peak Charge / 16 hours *1000 kW/ MW;

Hourly Off-Peak Charge - $/ MWh = Daily Off-Peak Charge / 24 hours *1000 kW/ MW.

2) The total demand charge in any week, pursuant to a reservation for Daily On-Peak Delivery or Daily Off-Peak Delivery, shall not exceed the Weekly Delivery rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity and any additional transmission service, if any, in any day during such week.

3) **Hourly delivery:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the amounts set forth above for a Point of Delivery.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (1) above for daily service times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (1) above for weekly service times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

4) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

5) **Congestion, Losses and Capacity Export:** A Transmission Customer desiring Non-Firm Point-to-Point Transmission Service may elect to pay transmission congestion charges. If the Transmission Customer so elects, it shall either (a) if the applicable Transmission Congestion Charge as calculated pursuant to Attachment K is positive, pay the higher of the applicable Transmission Congestion Charge or the applicable rate under section (1) above, or (b) if the

applicable Transmission Congestion Charge as calculated pursuant to Attachment K is negative, pay or be credited the sum of the applicable Transmission Congestion Charge and the rate under section (1) above. The Transmission Customer shall be responsible for losses as specified in the Tariff. Any Transmission Customer that is a Capacity Export Transmission Customer, shall pay for any applicable charges, and receive any applicable credits, for such a customer pursuant to Attachment DD.

6) **Other Supporting Facilities and Taxes:** In addition to the charges set forth in section (1) of this schedule, the Transmission Customer shall pay charges determined on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H for the applicable Zone(s) and any amounts necessary to reimburse the Transmission Provider for any amounts payable as 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.

7) **Transmission Enhancement Charges:** In addition to the rates set forth in Section (1) of this Schedule and any other applicable charges, the Transmission Customer shall also pay any Transmission Enhancement Charges for which it is designated as a Responsible Customer under Schedule 12 appended to the Tariff.

8) **Determination of monthly charges for ComEd Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of ComEd's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; (iii) Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") revenues allocable to ComEd under the Tariff; and (iv) any Point-To-Point Transmission Service where the Point of Receipt and the Point of Delivery are both internal to the ComEd Zone. On this basis, the sum of these revenues will appear as a reduction to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.

9) **Resales:** The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

ATTACHMENT H-12

Annual Transmission Rates -- Rockland Electric Company
for Network Integration Transmission Service

1. The annual transmission revenue requirement is $19,661,232 and the rate for Network Integration Transmission Service is $49,695 per megawatt per year.

2. The rate stated in section 1 above shall be effective until amended by the Regional Transmission Owner(s) within the Zone or modified by the Commission.

3. In addition to the rate set forth in section 1 above, the 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 the Regional Transmission Owners for any amounts payable by them as 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.

Appendix C

Direct Accounting Panel Testimony and Exhibits of John de la Bastide, Jack Deem, and Wenqi Wang

(Exhibit Nos. RECO-1 and RECO 2)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Rockland Electric Company	)))	**Docket No. ER17-__-000**

PREPARED DIRECT ACCOUNTING PANEL TESTIMONY ON BEHALF OF ROCKLAND ELECTRIC COMPANY

BACKGROUND AND QUALIFICATIONS

Q. Would the members of the Accounting Panel please state your names and business addresses?

A. John de la Bastide, One Blue Hill Plaza, Pearl River, New York 10965. Jack C. Deem, 4 Irving Place, New York, New York 10003. Wenqi Wang, 4 Irving Place, New York, New York, 10003.

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

A. **(de la Bastide)** I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland" or "O&R") where I hold the position of Director – Financial Services.

(Deem) I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison"). I hold the position of Department Manager - Regulatory Policy.

(Wang) I am also employed by Con Edison. I hold the position of Department Manager - Regulatory Accounting and Revenue Requirements.

Q. Please explain your educational background, work experience, and current general responsibilities.

A. **(de la Bastide)** I graduated from Hofstra University in l985 with a Bachelor of Business Administration in Accounting. I was employed by Con Edison for 30 years. Between l986 and l996, I was promoted to various supervisory positions in Corporate Accounting. In 1998, I was promoted to the position of Section Manager, Employee Benefits. In 2001, I was promoted to Department Manager, Financial Forecasting, in Corporate Accounting and have held various positions as Department Manager in Corporate Accounting and Electric Operations. I became Department Manager, Benefits and Compensation, in March 2007. In June 2011, I was promoted to Director of Compensation. In November 2016, I became an employee of O&R and assumed the role of Director of Financial Services.

(Deem) In December 1990, I received a Bachelor of Science Degree in Policy & Management from Carnegie Mellon University in Pittsburgh, Pennsylvania. I earned a Masters of Business Administration degree from Carnegie Mellon in June 1996. Before returning to Carnegie Mellon for my MBA, I worked as an analyst with Barakat & Chamberlin, Inc., where I was responsible for planning and evaluating demand-side management (“DSM”) programs for various utilities. In that role, I performed cost effectiveness screening and market penetration analysis of DSM measures and programs, prepared testimony entered on behalf of utilities during DSM cost recovery hearings, and implemented DSM tracking systems. After receiving my MBA, I worked as a consultant with Deloitte Consulting for 14 years. With Deloitte, I assisted companies in improving operations by leading the implementation of finance process, system, control, and organizational improvements. I joined Con Edison in June 2010 as Business & Solution Architect for the implementation of the Oracle Finance and Supply Chain system. I transitioned to my current role of Department Manager for Regulatory Policy in May 2014.

(Wang) In June 1999, I received a Bachelor of Science Degree in Accounting from the University at Albany, State University of New York. I began my employment with Con Edison in July 1999 as a Management Intern. I worked in the Corporate Accounting Department from July 2000 until April 2014. At first, I worked primarily in the General Accounts section as a Staff Accountant, then became a Supervisor, and ultimately the Department Manager. In May 2014, I assumed my current position as Department Manager of Regulatory Accounting and Revenue Requirements.

Q. Have any members of the Accounting Panel previously testified before the Federal Energy Regulatory Commission ("FERC" or the "Commission")?

A. No.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. Our testimony covers the following topics:

- An overview of the costs driving the need for electric transmission rate relief for Orange and Rockland's wholly owned subsidiary corporation, Rockland Electric Company ("RECO" or the "Company");
- The calculation of the electric transmission revenue requirement and new Schedule 1A charge requested by RECO in this filing; and

- A comparison of the requested revenue requirement to the revenues produced pursuant to RECO's current electric transmission rates.

Q. Please identify any exhibits to your testimony.

A. We are presenting Exhibit No. RECO-2, Electric Transmission Revenue Requirement, which contains the calculations supporting the Company's requested transmission revenue requirement. All of the schedules in this Exhibit were prepared under our supervision and direction. As indicated in the schedules, various other Company witnesses provided data contained in the schedules.

THE NEED FOR RATE RELIEF

Q. Please explain why the Company is filing to increase its electric transmission rates.

A. As noted by Company witness Peverly, O&R and RECO operate a single fully integrated electric transmission system (the "Integrated Transmission System"). For a description of the Company's investment across the Integrated Transmission System, please refer to Mr. Peverly's testimony. Because RECO has no operating employees, O&R and Con Edison provide all of RECO's administrative, corporate, and operating services. The Company has not increased its electric transmission rates since they were approved by the Commission in 2001. Furthermore, the rates approved in 2001 for RECO were apportioned from rates established in 1994, which means that it has been over two decades since RECO's transmission rates were updated. In the intervening years, O&R and RECO, on behalf of the Integrated Transmission System, have continued to invest in transmission infrastructure that is critical to providing safe and reliable electric service to RECO customers. In addition, O&R and RECO have worked to reduce costs and increase efficiencies. For example, O&R, in conjunction with Con Edison, has restructured organizations to institute standardized processes and to improve the management oversight of major capital projects. O&R, in conjunction with Con Edison, has also invested in new technology to move financial accounting reporting, forecasting and planning, and supply chain and payroll to a common platform. In addition, O&R and Con Edison continue to proactively manage employee benefit costs to offer market-competitive benefits and compensation packages designed to attract and retain the employees required to provide customers with safe and reliable service. O&R and Con Edison have migrated from defined benefit plans to defined contribution plans and introduced new health care options designed to make employees more aware of health care costs and encourage wellness.

Q. What change to the charges contained in Schedule 1A and Attachment H-12 is the Company's requesting?

A. The Company is requesting an increase in: (a) the Attachment H-12 transmission revenue requirement ("TRR") from $11,785,928 to $19,661,232; (b) the Network Integration Transmission Service rate from $32,114 per megawatt per year to $49,695 per megawatt per year; and (c) the Schedule 1A Transmission Owner Scheduling, System Control and Dispatch Service rate to $0.5351/MWh. RECO's current Network Integration Transmission Service rate and Transmission Owner Scheduling, System Control and Dispatch Service rate produce annual PJM transmission revenues of approximately

$12.3 million; therefore, the total increase in the Company revenues will be approximately $8.1 million. Currently, transmission revenues make up a small portion of customers' bills (approximately 6% of RECO's total revenues are PJM transmission revenues); therefore, the resulting estimated overall impact on customers' bills is approximately 3.4%.

Q. What are the specific drivers of the requested rate increases?

A. The most significant driver of the requested rate increase is the 121% increase in plant investment in the Integrated Transmission System since 1994. The increases in transmission plant are offset by a 9% lower fixed charge rate, a lower ROE, and a 22% lower RECO peak factor relative to the Integrated Transmission System-wide peak. How each of these elements is factored into the revenue requirement calculation is discussed next.

CALCULATION OF RECO'S TRANSMISSON REVENUE REQUIREMENT

Q. How did you determine the RECO electric transmission revenue requirement?

A. We started with the overall 2015 Integrated Transmission System-wide annual TRR of $69,841,504 which we calculated using the same model as the current TRR that resulted from the settlement approved by the Commission in Docket No. OA96-210-000. RECO's single system peak load in 2015 was 396 MW of the total 2015 Integrated Transmission System-wide peak load of 1,405 MW. In order to allocate an appropriate amount of transmission costs to the RECO pricing zone, we applied the ratio of 396 MW/1,405 MW to the overall Integrated Transmission System TRR. Using this methodology, we calculated a TRR for the RECO pricing zone of $19,661,232, which equates to

$49,694.75 per MW per year. The resulting annual transmission rate is $49.695 per kW. The TRR and annual transmission rate for network service will be set forth in Attachment H-12 of the PJM Tariff, and the rates for monthly, weekly, daily, and hourly point-to-point transmission service will be set forth in Schedules 7 and 8 of the PJM Tariff. Revised Tariff sheets are included with this filing.

Q. Why did you apply this method to calculate the TRR?

A. This is the method the Company used and the Commission approved in 2001 when establishing RECO's current rates.

Q. How did you calculate the 2015 Integrated Transmission System TRR?

A. We first took the 2015 Integrated Transmission System plant investment amount ($293,186,280) and multiplied it by a fixed charge rate (22.94%) to come up with the revenue requirement before line loss ($67,257,368). We then added the line loss revenue (3.7% based on billed sales and sendout data) to arrive at the revenue requirement for Integrated Transmission System plant investment ($69,841,504).

Q. How did the Company determine the 2015 Integrated Transmission System plant investment amount?

A. We took the Total Transmission Plant balance reported in Orange and Rockland Utilities, Inc., Rockland Electric Company and Pike County Light & Power Company's ("PCL&P") (collectively, the Companies) 2015 FERC Form No. 1 filing on page 206, Line 58, totaling $293,186,280. We would note that although the Companies FERC Form No. 1 does contain certain PCL&P information, PCL&P does not own any transmission facilities.

Q. How does the 2015 Integrated Transmission System plant investment amount compare to the equivalent amount embedded in current transmission rates?

A. The Integrated Transmission System plant investment amount embedded in current transmission rates uses the Integrated Transmission System plant balance on the books as of December 31, 1994 of $132,783,929. In comparison, the 2015 Integrated Transmission System plant balance on the books totals $293,186,280. That is a growth of $160,402,351 over the past 21 years.

Q. How did you calculate the appropriate fixed charge rate to apply to the 2015 Integrated Transmission System plant investment?

A. The fixed charge rate is a composite rate that includes the following cost factors: (1) O&M, (2) Other Taxes, (3) A&G, (4) Return, (5) Depreciation, (6) Composite Income Tax, (7) General Plant/Common Plant, (8) Cash Working Capital, and (9) Accumulated Deferred Income Tax Adjustment.

Q. What does the O&M component of the fixed charge rate represent and how was it calculated?

A: The O&M component of the fixed charge rate represents the percentage of transmission O&M incurred as it relates to the transmission plant investment. It was calculated by dividing the total Integrated Transmission System expense by the total Integrated Transmission System plant investment.

Q. What does the Other Taxes component of the fixed charge rate represent and how was it calculated?

A: The Other Taxes component of the fixed charge rate represents the percentage of Electric Taxes Other than Income Taxes incurred as it relates to the Total Electric Plant. We calculated it by dividing the Companies' Total Electric Taxes Other than Income Taxes by the Companies' Total Electric Plant-in-Service balance.

Q. What does the A&G component of the fixed charge rate represent and how was it calculated?

A: We calculated the A&G component by using the formula below for the Companies:

$$\frac{\text{Transmission Wages Expense}}{(\text{Total Wages Expense} - \text{A\&G Wages Expense})} \times \frac{\text{Total A\&G related O\&M}}{\text{Total Transmission Plant Investment}}$$

Q. What does the Return component of the fixed charge rate represent and how was it calculated?

A: The Return component of the fixed charge represents the Rate of Return that RECO is requesting. The Return component is comprised of the sum of the following two components: (1) weighted long-term debt cost, and (2) weighted common stock equity cost. We calculated the weighted long-term debt cost by using the formula below for the Companies:

$$\frac{\text{Long-Term Debt Payable}}{\text{Total Capitalization}} \times \frac{\text{Long-Term Debt Interest + Amortization of Debt Discount and}}{\text{Long-Term Debt}}$$

We calculated the weighted common stock equity cost by using the formula below for the Companies:

$$\frac{\text{Common Stock Equity}}{\text{Total Capitalization}} \times \text{Return on Equity}$$

Q. What does the Depreciation component of the fixed charge rate represent

and how was it calculated?

A: We calculated the Depreciation component of the fixed charge rate by first dividing the Transmission depreciation expense by total Integrated Transmission System plant investment to obtain the Transmission Depreciation ratio. Then we calculated the Depreciation component using this formula:

$$\frac{\text{Return Component}}{(1+\text{Return Component})^{\wedge}\text{Transmission Depreciation Ratio}-1}$$

Q. What does the Composite Income Tax component of the fixed charge rate represent and how was it calculated?

A: We calculated the Composite Income Tax component of the fixed charge rate by using the formula below for the Companies:

$$\frac{(35/65) + \text{State Tax Rate}}{1 - \text{State Tax Rate}} \times \begin{matrix}\text{Return component} \\ + \\ \text{Depreciation component} \\ - \\ \text{Transmission Depreciation Ratio}\end{matrix} \times \left[1- \frac{\text{Weighted Long-Term Debt Cost}}{\text{Return component}} \right]$$

Q. What does the General Plant / Common Plant component of the fixed charge rate represent and how was it calculated?

A: We calculated the General Plant / Common Plant component of the fixed charge rate by using the formula below for the Companies:

$$\frac{\text{Transmission Wages Expense}}{(\text{Total Wages Expense} - \text{A\&G Wages Expense})} \times \begin{matrix}\text{General Plant} \\ + \\ \text{Electric Plant-in-Service}\end{matrix}$$

multiplied by

$$\frac{\text{Other Taxes component} + \text{Return component} + \text{Depreciation component} + \text{Composite Income Tax component} - \text{Accumulated Deferred Income Tax Adjustment component}}{\text{Total Transmission Plant Investment}}$$

Q. What does the Cash Working Capital component of the fixed charge rate represent and how was it calculated?

A: We calculated the Cash Working Capital component of the fixed charge rate by using the formula below for the Companies:

$$\frac{(\text{Total Transmission Expense} * .125) * (\text{Return component} + \text{Composite Income Tax component})}{\text{Total Transmission Plant Investment}}$$

Q. What does the Accumulated Deferred Income Tax component of the fixed charge rate represent and how was it calculated?

A: We calculated the Accumulated Deferred Income Tax component of the fixed charge rate by adjusting the fixed charge rate to reflect the Companies' Accumulated Provision for Deferred Income Taxes. Since ratepayers have already paid these monies to the Companies, the Companies are not allowed to earn a return or an allowance for taxes on the amount. Accordingly, the Accumulated Deferred Income Tax component removes the return on taxes associated with the typical balance of the Companies' Accumulated Provision for Deferred Income Taxes. We calculated this adjustment by multiplying -0.1 by the sum of the Return Component and the Composite Income Tax Component.

COMPARISON OF THE REQUESTED REVENUE REQUIREMENT TO THE REVENUES PRODUCED PURSUANT TO RECO'S CURRENT ELECTRIC TRANSMISSION RATES

Q. What impact does the return on equity ("ROE") have in this rate request?

A. The ROE reflected in RECO's current electric transmission rates is 11.11 %. As set forth in the testimony of RECO witness MacKenzie, in this filing RECO is seeking an overall ROE of 10.7%.

Q. How does the fixed charge rate included in this rate filing compare to the fixed charge rate embedded in the current TRR?

A. The fixed charge rate embedded in current TRR is 25%, as compared with the fixed charge rate of 23% that is reflected in this rate filing.

Q. How did the Company determine the peak load factors for the total Integrated Transmission System and for the RECO portion of the Integrated Transmission System?

A. We looked at the monthly peak demands for the calendar year 2015 as reported in the Companies' 2015 FERC Form No. 1 filings on page 401, Lines 29d-40d. The highest monthly peak demands for O&R and RECO were then selected to become the peak load factors for the overall O&R transmission system, as compared with the highest monthly peak demands for RECO.

Q. How do the Integrated Transmission System and RECO-specific peak load factors in this rate filing compare to the equivalent factors embedded in RECO's current electric transmission rates?

A. The Integrated Transmission System and RECO-specific peak load factors in this case are 1,405 MW and 396 MW, respectively. Meanwhile, the Integrated Transmission System and RECO specific peak load factors embedded in current electric transmission rates are 1,022 MW and 367 MW, respectively.

Q. Please summarize the revenue requirement components of the current rates and RECO's proposed rates.

A. Please see the table below.

	1994*	2015
Integrated Transmission System plant investment	$ 132,783,929	$ 293,186,280
Fixed Charge Rate Components		
(1) O&M	6%	4%
(2) Other Taxes	4%	3%
(3) A&G	4%	5%
(4) Return	10%	8%
(5) Depreciation	0%	0%
(6) Composite Inc. Tax	2%	2%
(7) General Plant/Common Plant	0%	2%
(8) Cash Working Capital	0%	0%
(9) ADIT Adjustment	-1%	-1%
Fixed Charge Rate	25%	23%
Revenue Requirement Before Line Loss	33,578,482	67,257,368
Line Loss Factor	3.00%	3.70%
Line Loss Revenue	1,038,510	2,584,136
Integrated Transmission System-wide annual transmission revenue requirement	34,616,992	69,841,504
Integrated Transmission System-Wide Peak Load	1,022	1,405
Revenue Requirement per MW (Transmission Rate)	33,872	49,695
RECO Single System Peak Load (MW)	367	396
RECO Transmission Revenue Requirement	$ 12,430,955	$ 19,661,232

* RECO's current authorized TRR is $11,785,928. In preparing this line item level calculation for comparison to RECO's requested TRR using 1994 input data, the comparative calculation displayed is $12,430,955.

Q. Do any of your exhibits address in further detail the elements of the TRR you have summarized?

A. Yes, Exhibit No. RECO-2 does so.

Q. Are you updating any other rates?

A. Yes, we are also updating the rate for Schedule 1A, Transmission Owner Scheduling, System Control and Dispatch Service.

Q. What is the 2015 Schedule 1A rate and how does it compare to the current rate?

A. The 2015 Schedule 1A rate is calculated to be $0.5351 per megawatt hour, compared to $0.2475 per megawatt hour in current rates.

Q. How did you calculate the 2015 Schedule 1A rate?

A. The 2015 Schedule 1A rate calculation is shown in the summary page of Exhibit No. RECO-2, Electric Transmission Revenue Requirement. We started out with the O&R Scheduling System Control and Dispatch Revenue Requirement, which is a cumulation of 2015 O&M costs from our cost center 2780, Control Center Operations - OR ECC. This amounted to $3,052,183. We then divided this amount by the Companies' System Billing Units (or total customer megawatt sales less sales for resale to other utilities: RECO and PCL&P) of 5,703,541 to arrive at a rate of $0.5351 per megawatt hour. The new RECO PJM zone revenue requirement for Scheduling System Control and Dispatch of $786,001 was calculated by multiplying this rate by the RECO PJM zone billing units of 1,468,886 megawatt hours. Please note that the current overall RECO Scheduling System Control and Dispatch rate of $0.2621 per megawatt hour was calculated using a similar approach as described above. However, historically we also applied a PJM Non-Zone Adjustment Factor of 0.9441425 to account for the rate's application to the PJM portion of RECO's service territory for an applied rate of $0.2475 per megawatt hour. This adjustment factor was based on the portion of peak day RECO load that was in the PJM zone. In this filing, we started with megawatt hours specific to the RECO PJM zone so no adjustment factor was necessary.

Q. Does this filing include the cost of service statements required by the Commission?

A. Yes, please see Statements AA through BM as required by the Commission's regulations, for Period I and Period II. These statements consist of the following:

Statement AA consists of balance sheets as of the end of both Period I, *i.e.*, December 31, 2015, and Period II, *i.e.*, June 30, 2017.

Statement AB consists of income statements for both Period I and Period II.

Statement AC consists of retained earnings statements for Period I and Period II.

Statement AD consists of statements of the cost of plant in service.

Statement AE consists of statements of accumulated depreciation and amortization of RECO's plant for Periods I and II.

Statement AF consists of statements of RECO's accumulated deferred income taxes.

Statement AG consists of RECO's electric plant held for future use, construction work in progress, and deferred income taxes.

Statement AH consists of statements for Period I and Period II of RECO's operation and maintenance expenses.

Statement AI consists of statements for Periods I and II of total wages and salaries paid.

Statement AJ consists of statements for Periods I and II of RECO's depreciation and amortization expenses.

Statement AK consists of statements for Periods I and II of taxes other than income taxes.

Statement AL consists of statements for Period I and II of working capital.

Statement AM consists of statements for Periods I and II of construction work-in-progress.

Statement AN is inapplicable because RECO did not have a notes payable balance at the end of Period I and is not projected to have a notes payable balance at the end of Period II.

Statement AO: We will be seeking a waiver for this statement for Periods I and II.

Statement AP consists of statements for Periods I and II of the interest charges taken as federal income tax deductions.

Statement AQ consists of statements for Periods I and II of federal income tax deductions for items other than interest.

Statement AR is inapplicable because RECO did not have any federal income tax deductions or adjustments for Period I and is not projected to have any federal income tax deductions or adjustments for Period II.

Statement AS consists of statements for Periods I and II of additional state income tax deductions.

Statement AT consists of statements for Periods I and II of state tax adjustments.

Statement AU consists of statements for Periods I and II of miscellaneous service revenues, rent from electric property and other electric revenues.

Statement AV consists of statements for Period I and Period II addressing rate of return.

Statement AW is inapplicable, as RECO does not have any debt on its books.

Statement AX is inapplicable, as there are no other pending matters seeking a rate change for RECO.

Statement AY consists of statements for Periods I and II of income and revenue tax rate data.

Statement BA describes RECO's four service categories.

Statement BB requests information about assigning costs to various customer classes.

Statement BC: We will be seeking a waiver for these statements for Periods I and II.

Statement BD: Please see Statement BB.

Statement BE: Please see Statement BB.

Statement BF: We will be seeking a waiver for these statements for Periods I and II.

Statement BG reflects the proposed revenue requirement.

Statement BH reflects the present revenue requirement.

Statement BI is inapplicable to RECO.

Statement BJ-BK: We will be seeking a waiver for these statements for Periods I and II.

Statement BL consists of rate design information for Periods I and II.

Statement BM is inapplicable because RECO is not seeking a return on construction work in progress.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF NEW YORK	)
	) **ss**
COUNTY OF New York	)

I, JACK C. DEEM, being first duly sworn on oath depose and say as follows:

The foregoing "Prepared Direct Accounting Testimony on Behalf of Rockland Electric Company" was prepared by me and the other witnesses listed therein, or under the supervision of one or more of such witnesses, and the factual statements contained in such testimony are true and correct to the best of my knowledge, information and belief.

Further affiant saith not.

Jack C. Deem

Jack C. Deem

On this 19th day of JAN, 2017, before me, the undersigned notary public, personally appeared Jack C. Deem and acknowledged to me that he signed the forgoing document voluntarily for its stated purposes. I identified Jack C. Deem to be the person whose name is signed on the forgoing document by means of the following satisfactory evidence of identity (check one):

✓ Identification based on my personal knowledge of his/her identity, or

___ Current government-issued identification bearing his/her photographic image and signature.

Marietta De Luca

Notary Public
My commission expires:

MARIETTA DE LUCA
Notary Public, State of New York
No. 01DE4702217
Qualified in Kings County
Cert. Filed in New York County
Commission Expires March 30, 2019

STATE OF NEW YORK)
) **ss**
COUNTY OF NEW YORK)

I, WENQI WANG, being first duly sworn on oath depose and say as follows:

The foregoing "Prepared Direct Accounting Testimony on Behalf of Rockland Electric Company" was prepared by me and the other witnesses listed therein, or under the supervision of one or more of such witnesses, and the factual statements contained in such testimony are true and correct to the best of my knowledge, information and belief.

Further affiant saith not.

Wenqi Wang

On this 19th day of JAN, 2017, before me, the undersigned notary public, personally appeared Wenqi Wang and acknowledged to me that he signed the forgoing document voluntarily for its stated purposes. I identified Wenqi Wang to be the person whose name is signed on the forgoing document by means of the following satisfactory evidence of identity (check one):

√ Identification based on my personal knowledge of his/her identity, or

___ Current government-issued identification bearing his/her photographic image and signature.

Marietta DeLuca
Notary Public
My commission expires:

MARIETTA DE LUCA
Notary Public, State of New York
No. 01DE4702217
Qualified in Kings County
Cert. Filed in New York County
Commission Expires March 30, 2019

STATE OF NEW YORK)
) ss
COUNTY OF Rockland)

I, JOHN DE LA BASTIDE, being first duly sworn on oath depose and say as follows:

The foregoing "Prepared Direct Accounting Testimony on Behalf of Rockland Electric Company" was prepared by me and the other witnesses listed therein, or under the supervision of one or more of such witnesses, and the factual statements contained in such testimony are true and correct to the best of my knowledge, information and belief.

Further affiant saith not.

John de la Bastide

John de la Bastide

On this 20 day of Jan, 2017, before me, the undersigned notary public, personally appeared John de la Bastide and acknowledged to me that he signed the forgoing document voluntarily for its stated purposes. I identified John de la Bastide to be the person whose name is signed on the forgoing document by means of the following satisfactory evidence of identity (check one):

✓ Identification based on my personal knowledge of his/her identity, or

___ Current government-issued identification bearing his/her photographic image and signature.

Denise A. Collins

Notary Public
My commission expires: May 27, 2019

DENISE A. COLLINS
Notary Public, State of New York
Registration #01CO5078588
Qualified In Rockland County
Commission Expires May 27, 20 19

Rockland Electric Company

Comparison of Transmission Billing Rates

Current Rates in Effect (1994 Filing)

RECO Zone - Current Rate (1994 Filing)		
Transmission Rev Req	$	11,785,928
Annual Peak (MW)		367
Transmission Rate ($/MW-Year)	$	32,114.25

PJM Scheduling System Control and Dispatch Rate ($/MWH)		
O&R System Revenue Requirement	$	1,288,426
System Billing Units (MWH)		4,915,358
Rate ($/MWH)	$	0.2621
RECO Billing Units (MWH)		1,319,411
RECO Share of Revenue Requirement	$	345,818
RECO Rate ($/MWH)	$	0.2621
PJM Non-Zone Adjustment Factor		0.9441425
Final RECO Rate ($/MWH)	$	0.2475

New Rates Asked For (2015 Filing)

See EXHIBIT RECO-2, Schedules 1 and 2

RECO PJM Zone - 2015 Consolidated Rate		
Transmission Rev Req	$	19,661,232
Annual Peak (MW)		395.64
Transmission Rate ($/MW-Year)	$	49,694.75

Consolidated Revenues		
Transmission Rev Req	$	69,841,504
Annual Peak (MW)		1,405.41
Transmission Rate ($/MW-Year)	$	49,694.75

PJM Scheduling System Control and Dispatch Rate ($/MWH)		
O&R System Revenue Requirement (See EXHIBIT RECO-2, Schedule 3)	$	3,052,183
System Billing Units (MWH)		5,703,541
Rate ($/MWH)	$	0.5351
RECO Billing Units (MWH)		1,468,886
RECO Share of Revenue Requirement	$	786,001
RECO Rate ($/MWH)	$	0.5351

FILE NAME: O&R 2015 Transmission Rate

FIXED CHARGE WORKSHEET

DATA BASED ON INDICATED FERC SOURCE WIT
CERTAIN ADJUSTMENTS. DETAIL ATTACHED

Company:	Orange & Rockland
	Consolidated System Data
Docket No.:	RM95-8-000 (FERC NOPR)
Form No.1:	2015 DATA

O&M Expense:

(Note: This section should only be completed if sales are based on system average energy cost)

Production

A. Total Power Production Expenses (p321.80b)			>	218,945,902
B. Purchased Power Expenses (p321.76b)			>	217,140,033
C. Energy Related O&M				
(p320.5b)	>	N/A		
(p320.7b)	>	N/A		
(p320.8b) Cred	>	N/A		
(p320.15b)	>	N/A		
(p320.17b)	>	N/A		
(p320.18b)	>	N/A		
(p320.25b)	>	N/A		
(p320.35b)	>	N/A		
(p320.37b)	>	N/A		
(p320.38b)	>	N/A		
(p320.56b)	>	N/A		
(p320.63b)	>	N/A		
		=	N/A	
D. Total Production Plant Investment (p.206.42g) Average or End-of-Year			>	N/A

$$\frac{A-B-C}{D} = \text{N/A}$$

Transmission:

A. Total Transmission Expenses (p321.100b)	>	$12,444,476
B. Transmission by Others (p321.88b)	>	$0
C. Total Transmission Plant Investment (p206.53g) Average or End-of-Year	>	$293,186,280

$$\frac{A-B}{C} = 0.0424$$

OTHER TAXES EXPENSE

X. Other Taxes (Electric Only) (p.114.13e)	>	43,934,737
Y. Electric Plant in Service (p.207.88g) Average or End-of-Year	>	1,690,149,297

X/Y = 0.0260

A&G EXPENSE

A. Production Wages Expense (p.354.18b)	>	0
B. Transmission Wages Expense (p.354.19b)	>	8,058,739
C. A&G Wages Expense (p.354.24b)	>	7,657,211
D. Total Wages Expense (p.354.25b)	>	62,051,330
E. Total A&G related O&M (p.323.168b)	>	95,849,092
P. Total Production Plant Investment (p.206.42g)	N/A	
T. Total Transmission Plant Investment (p.206.53g)		293,186,280

Production A&G Expense:

$$\frac{A}{(D-C)} \times \frac{E}{P} = \text{N/A}$$

Transmission A&G Expense:

$$\frac{B}{(D-C)} \times \frac{E}{T} = 0.0484$$

DEPRECIATION EXPENSE

DEp =	Production Depreciation Expense (Sum of p. 336.2b through p. 336.6b)	>	N/A
DEt =	Transmission Depreciation Expense (p. 336.7b)	>	7,758,874
P =	Total Production Plant Investment (p. 206.42g)		N/A
T =	Total Transmission Plant Investment (p. 206.53g)		293,186,280

Production Depreciation

$$SLDp = \frac{DEp}{P} = \text{N/A}$$

n = N/A

$$SFDp = \frac{R}{(1+R)n-1} = \text{N/A}$$

Transmission Depreciation

$$SLDt = \frac{DEt}{T} = 0.0265$$

n = 38

$$SFDt = \frac{R}{(1+R)n-1} = 0.0050$$

COMPOSITE INCOME TAX EXPENSE

State Tx > 7.25%

Production CIT= N/A Formula: (35/65+State Tx)/(1-State Tx)*(ROR+SFD-SLD)*(1-Wtd.LTD/ROR)

Transmission CIT= 0.0244 Formula: (35/65+State Tx)/(1-State Tx)*(ROR+SFD-SLD)*(1-Wtd.LTD/ROR)

General Plant/Common Plant : 218,116,033
(p.206.83g/p.356)

PRODUCTION G.P. = N/A

TRANS. G.P. = 0.1482

RATE OF RETURN WORKSHEET
--------------- -------------- ------

1. Common Stock Calculation

	Proprietary Capital (p.112.14d)	>	629,346,197
Less:	Preferred Stock (p.112.3d)	>	0
Less:	Account No. 216.1 (p.112.12d)	>	15,420,517
	Common Stock =		613,925,680

2. Rate of Return Calculation

LTD = Long Term Debt (Total) (p.112, sum of 16d thru 19d) (details on pp. 256-257)	>	663,200,000
PF = Preferred Stock (Total) (p.112.3d)		0
Common Stock (See Above)		613,925,680
Total Capital =		1,277,125,680
i = LTD interest (p.117, sum of 56c thru 60c) (details on p.257)	>	32,681,795
d(pf) = Preferred Dividends (p.118.29c)	>	0

LTD/CAP	0.5193	Cost:	0.0493	Weighted LTD Cost	0.0256
Pf/CAP	0.0000	Cost:	0.0000	Weighted Pf Cost	0.0000
COM/CAP	0.4807	Cost:	0.1070	Weighted Common Cost	0.0514

rate of return on common equity > 10.70%

OVERALL RATE OF RETURN = 0.0770

Source: Consultant at 10.2% + adder for being part of PJM

SUMMARY

	Production	Transmission
(1) O&M	N/A	0.0424
(2) Other Taxes	N/A	0.0260
(3) A&G	N/A	0.0484
(4) Return	N/A	0.0770
(5) Depreciation	N/A	0.0050
(6) Composite Inc. Tax	N/A	0.0244
(7) General Plant/Common Plant	N/A	0.0157
(8) Cash Wkg. Cap.	N/A	0.0005
(9) ADIT Adjustment*	N/A	-0.0101
FIXED CHARGE RATE (Use for system avg. fuel sales)	N/A	0.2294
FIXED CHARGE RATE LESS O&M** (Use for all other sales)	N/A	

NAMEPLATE CAPACITY (MW) (Sum of 402.5 thru 407.5 > +410c)	N/A	ANNUAL PEAK (MW) (p.401.29d-40d) >	1,405

Losses > 3.70%
From: GA (Line Loss)

For system sales the annual production cost equals:***	N/A
For system sales the annual transmission cost equals:	$49.695

Scheduling System Control and Dispatch

Revenue Requirement	$	3,052,183
Annual Billing Units		5,703,541
Rate ($/MWh)	$	0.5351

Load Dispatching Rate
For Network Integration Service, the annual transmission cost equals: $67,257,368

The hourly cost is based on the 5-day--16-hour convention with a daily and weekly caps of:

HOURLY COS	0.0000	HOURLY COST	0.01195
Daily Cap	0.0000	Daily Cap	0.1911
Weekly Cap	0.0000	Weekly Cap	0.9557

NOTE: 1 MW = 1000 KW

* Item 9 is an adjustment to the fixed charge rate to reflect the utility's Accumulated Provision for Deferred Income Taxes. Since the ratepayers have already paid these monies to the utility, the utility is not allowed a return or an allowance for taxes on the amount. Accordingly, Item 7 removes the return on taxes associated with the typical balance of the utility's Accumulated Provision for Deferred Income Taxes.

** Use the FCR without O & M in the stacking sheet.

*** Annual cost includes General Plant and 3% losses.

File Name: O&R 2015 Transmission Rates

Includes adjustments to FERC Data
To breakout Energy Control Center
Costs and Consolidation Entries

ORANGE AND ROCKLAND UTILITIES, INC.
CONSOLIDATED, INTEGRATED SYSTEM
INPUT DATA FOR FERC FIXED CHARGES WORKSHEET
2015 DATA

TARIFF INPUT ITEM	ORU	RECO	PIKE (A)	ADJ'S	NOTE	TOTAL SYSTEM
(All page, line and column references are to FERC Form 1)						
Total Power Production Exp						
(p321.80b)	136,787,020	102,042,399	3,432,044	(23,315,561)	A	218,945,902
Purchased Power Expense						
(p321.76b)	136,369,527	102,042,306	3,432,044	(23,315,561)	A	
				(1,388,283)	B	217,140,033
Energy Relate O&M items						
(p320.5b)	-	-	-	-		-
(p320.7b)	-	-	-	-		-
(p320.8b)	-	-	-	-		-
(p320.15b)	-	-	-	-		-
(p320.17b)	-	-	-	-		-
(p320.18b)	-	-	-	-		-
(p320.25b)	-	-	-	-		-
(p320.35b)	-	-	-	-		-
(p320.37b)	-	-	-	-		-
(p320.38b)	-	-	-	-		-
(p320.56b)	-	-	-	-		-
(p320.63b)	-	-	-	-		-
Total Production Plant Investment						
(p206.42g)	-	-	-	-		-

ORANGE AND ROCKLAND UTILITIES, INC.
CONSOLIDATED, INTEGRATED SYSTEM
INPUT DATA FOR FERC FIXED CHARGES WORKSHEET
2015 DATA

TARIFF INPUT ITEM	ORU	RECO	PIKE (A)	ADJ'S	NOTE	TOTAL SYSTEM
Total Transmission Expense						
(p321.112b)	13,950,118	2,125,414	44,355	(625,002)	C	12,444,476
				(3,050,409)	F	
Transmission by Others						
(p321.96b)	-	-	-	-		-
Total Transmission Plant Investment						
(p206.58g)	261,986,524	31,199,756	-	-		293,186,280
Other Taxes (Electric Only)						
(p114.14)						
Total	41,522,281	1,849,570	562,886	-		43,934,737
						43,934,737
Electric Plant in Service						
(p207.104g)	1,203,006,520	316,197,530	21,666,230	-		1,540,870,280
Common plant allocated to						
electric operations (p356 * 70.75%)	149,279,017	-	-	-		149,279,017
						1,690,149,297
Electric Production Wages Expense						
(p354.20b)	500	32	-	(532)	D	-
Electric Transmission Wages Expense						
(p354.21b)	7,271,875	775,183	11,681	-		8,058,739
Electric A&G Wages Expense						
(p354.27b)	5,791,520	1,786,559	79,132	-		7,657,211

ORANGE AND ROCKLAND UTILITIES, INC.
CONSOLIDATED, INTEGRATED SYSTEM
INPUT DATA FOR FERC FIXED CHARGES WORKSHEET
2015 DATA

TARIFF INPUT ITEM	ORU	RECO	PIKE (A)	ADJ'S	NOTE	TOTAL SYSTEM
Total Electric Wages Expense						
(p354.28b)	51,089,038	10,100,080	862,212	-		62,051,330
Total A&G Related O&M						
(p323.197b)	77,737,431	20,296,250	1,126,042	(3,308,922)	C	
				(1,709)	F	95,849,092
Exclude DSM and HIECA costs inluded in Acct. 930.2	-	-	-	-		-
						95,849,092
Production Depreciation Expense						
(Sum of p336.2b through p336.6b)	-	-	(16,000)	16,000	D	-
Transmission Depreciation Expense						
(pp336.7b)	6,691,368	1,067,506	-	-		7,758,874
General Plant						
(p207.99g)	59,264,206	7,009,426	2,563,384	-		68,837,016
Proprietary Capital						
(p112.16c minus 15c) - excl OCI	629,346,197	247,604,603	5,777,270	(253,381,873)	C	
						629,346,197
Preferred Stock						
(p112.3c)	-	-	-	-		-
Unappropriated Undistributed Subsidiary Earnings (216.1)						
(p112.12c)	292,208,259	-	-	292,208,259	E	
				(15,420,517)	E	15,420,517
Long Term Debt (Total)						
(p112, sum of 18c through 21c)	660,000,000	-	3,200,000	-		663,200,000
LTD interest						
(p117, sum of 52c through 66c)	32,442,166		239,629	-		32,681,795

ORANGE AND ROCKLAND UTILITIES, INC.
CONSOLIDATED, INTEGRATED SYSTEM
INPUT DATA FOR FERC FIXED CHARGES WORKSHEET
2015 DATA

TARIFF INPUT ITEM		ORU	RECO	PIKE (A)	ADJ'S	NOTE	TOTAL SYSTEM
Preferred Dividends (p118.29c)		-	-	-	-		-
Monthly Peak Demands (p401.29d-40d)	Jan	668.02	230.62	12.64			911.28
	Feb	661.52	216.53	12.61			890.67
	Mar	608.01	208.64	11.65			828.30
	Apr	518.99	176.36	9.37			704.72
	May	818.29	321.82	12.97			1,153.08
	Jun	903.82	351.20	14.83			1,269.85
	Jul	994.21	395.64	15.56			1,405.41
	Aug	981.82	379.03	15.51			1,376.36
	Sep	993.05	389.16	15.41			1,397.63
	Oct	549.64	181.49	9.96			741.09
	Nov	576.84	198.57	10.72			786.14
	Dec	599.56	205.37	10.89			815.82
Annual Peak Demand		994.21	395.64	15.56	-	-	1,405.41

NOTES:

(A) Eliminate sales for resale from ORU to RECO and PIKE
(B) Exclude deferred fuel of subsidiaries
(C) Consolidating elimination (Joint Use Rents)
(D) To eliminate production expenses
(E) Exclude Undistributed Earnings of Utility Subsidiaries. Net amount reported for the consolidated system is the Undistributed Earnings of the Non-regulated subsidiaries.
(F) Exclude costs which will be recovered through ancillary service charge rate.(ECC Load Dispatching Costs recovered as part of a separate transmission rate) - Source BI Query Section 2780 2015 O&M Costs

Scheduling System Control and Dispatch	O&R	RECO	Pike	O&R System
Revenue Requirement	$ 2,224,976	$ 786,057	$ 41,150	$ 3,052,183
Annual Billing Units (kwh)	4,157,759	1,468,886	76,896	5,703,541
Rate ($/MWh)	0.5351	0.5351	0.5351	0.5351

ECC 2015 O&M Costs (Cost Center 2780)

Sum of Transaction Amount				
GL Ferc Account Code2	**GL Ferc Account Code**	**GL Ferc Account Name**	**GL Activity Name**	**Total**
Power S	**5560**	SYSTEM CONTROL AND LOAD DISPATCHING	PERFORM SYSTEM CONTROL AND LOAD DISPATCH	65.00
		SYSTEM CONTROL AND LOAD DISPATCHING Total		65.00
Power Supply Total				**65.00**
Transmi	**5600**	OPERATION SUPERVISION AND ENGINEERING	PROVIDE TRANSMISSION OPS SUPERVISION AND ENGINEERING	3,484.02
			PROVIDE TRANSMISSION OPS SUPERVISION AND ENGINEERING NERC	33,957.23
		OPERATION SUPERVISION AND ENGINEERING Total		37,441.25
	5611	LOAD DISPATCH RELIABILITY	PROVIDE DISPATCHING RELIABILITY	402,287.69
		LOAD DISPATCH RELIABILITY Total		402,287.69
	5612	LOAD DISPATCH MONITOR & OPERATE TRANSM SYS	PERFORM SYSTEM CONTROL AND LOAD DISPATCH	(1,431.66)
			PROVIDE LOAD DISPATCHING TRANSMISSION	400,843.99
			PROVIDE OPERATIONAL AND ADMIN SUPPORT OTHER	513,930.45
		LOAD DISPATCH MONITOR & OPERATE TRANSM SYS Total		913,342.78
	5613	LOAD DISPATCH TRANSMISSION SERVICE AND SCHEDULING	CONTROL SYSTEM VOLTAGE	805,812.88
			PERFORM TRANSMISSION SCHEDULING	401,605.57
		LOAD DISPATCH TRANSMISSION SERVICE AND SCHEDULING Total		1,207,418.45
	5614	SCHEDULING,SYSTEM CONTROL & DISPATCHING SERVICES	PERFORM TRANSMISSION SCHEDULING	0.00
		SCHEDULING,SYSTEM CONTROL & DISPATCHING SERVICES Total		0.00
	5615	LT RELIAB PLANN& STANDARDS DEVELOPMT	PERFORM LONG TERM RELIAB AND PLANNING STANDARDS DEVELOPMENT	402,384.12
			PROVIDE SYSTEM CERTIFICATION SUPPORT	88,503.76
		LT RELIAB PLANN& STANDARDS DEVELOPMT Total		490,887.88
	5618	LT RELIAB PLANN & STANDARDS DEVEL SVCS	PROVIDE SYSTEM CERTIFICATION SUPPORT	0.00
		LT RELIAB PLANN & STANDARDS DEVEL SVCS Total		0.00
	5660	MISCELLANEOUS TRANSMISSION EXPENSES	PROVIDE INTERNAL COMPLIANCE PROGRAM	(301.86)
			PROVIDE TRANSMISSION OPS SUPPORT	(505.75)
		MISCELLANEOUS TRANSMISSION EXPENSES Total		(807.61)
	5690	MAINTENANCE OF STRUCTURES TRANSMISSION	MAINTAIN COMMUNICATION EQUIP	(23.29)
			MAINTAIN COMPUTER HARDWARE	(69.02)
			MAINTAIN COMPUTER SOFTWARE	(69.02)
		MAINTENANCE OF STRUCTURES TRANSMISSION Total		(161.33)
Transmission Total				**3,050,409.11**
Admin	**9260**	OTHER EMPLOYEE BENEFITS EXPENSES	PROVIDE SAFETY EQUIP	2,962.79
		OTHER EMPLOYEE BENEFITS EXPENSES Total		2,962.79
	9302	MISCELLANEOUS GENERAL EXPENSES	PROVIDE EMPLOYEE WELLNESS REIMBURSEMENT	150.00
		MISCELLANEOUS GENERAL EXPENSES Total		150.00
	9310	GENERAL RENTS	PROVIDE OPERATING FACIL MTCE	(1,403.76)
		GENERAL RENTS Total		(1,403.76)
Admin Total				**1,709.03**
Grand Total				**3,052,183.14**

Joint Use Rents

	Pike Electric		RECO	
	A&G	Transmission	A&G	Transmission
JAN-15	17,576	2,990	259,915	54,853
FEB-15	17,576	2,990	259,915	54,853
MAR-15	17,576	2,990	259,915	54,853
APR-15	17,576	2,990	259,915	54,853
MAY-15	17,576	2,990	259,915	54,853
JUN-15	17,576	2,990	259,915	54,853
JUL-15	17,588	2,521	256,408	43,803
AUG-15	17,588	2,521	256,408	43,803
SEP-15	17,588	2,521	256,408	43,803
OCT-15	17,588	2,521	256,408	43,803
NOV-15	17,588	2,521	256,408	43,803
DEC-15	17,588	2,521	256,408	43,803
	210,984	33,066	3,097,938	591,936

Appendix D

Direct Testimony and Exhibits of Francis Peverly

(Exhibit Nos. RECO-3 and RECO-4)

EXHIBIT NO. RECO-3

UNITED STATES OF AMERICA
BEFORE
THE FEDERAL ENERGY REGULATORY COMMISSION

	)	
Rockland Electric Company	**)**	**Docket No. ER17-___-000**
	)	

PREPARED DIRECT TESTIMONY OF
FRANCIS W. PEVERLY
ON BEHALF OF ROCKLAND ELECTRIC COMPANY

UNITED STATES OF AMERICA
BEFORE
THE FEDERAL ENERGY REGULATORY COMMISSION

Rockland Electric Company	)))	**Docket No. ER17-___-000**

PREPARED DIRECT TESTIMONY OF
FRANCIS W. PEVERLY
ON BEHALF OF ROCKLAND ELECTRIC COMPANY

I. Background and Qualifications

Q. Please state your name and business address.

A. My name is Francis W. Peverly. My business address is 390 West Route 59, Spring Valley, New York 10977.

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

A. I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland"), the parent company of Rockland Electric Company ("RECO" or the "Company"), where I hold the position of Vice President – Operations.

Q. Please describe your educational background, work experience and current responsibilities.

A. I graduated from Clarkson University in 1985 with a Bachelor of Science, Industrial Distribution. In 1992, I received a Masters of Business Administration degree from Marist College. I also am a Project Management Professional. As the Vice President – Operations for Orange and Rockland, I am responsible for providing administrative, operational, and management leadership for the operating and engineering organizations in the company. Over my 30 years in the utility business, I have held a number of management and engineering assignments in Electric Operations, Gas Operations, and Construction Management. I joined Orange and Rockland from Central Hudson Gas and Electric Corporation as an electric operations division line supervisor in 1989, and steadily rose through the ranks, serving in positions of increasing responsibility, including division engineer, general distribution supervisor, assistant manager of Gas Operations, manager of Gas Operations, and general manager of Electric Operations. I then joined Consolidated Edison Company of New York, Inc. ("Con Edison"), an affiliate of both Orange and Rockland and RECO, as general manager, Bronx/Westchester Electric Operations. I also served as general manager of Construction Management in Central Operations at Con Edison. I sit on the Executive Committee of the Edison Electric Institute's ("EEI") Transmission, Distribution, and Metering Committee, vice-chair EEI's Asset Management Subcommittee, sit on the board of directors of the Northeast Gas Association, sit on the PJM Transmission Owner's Designated Officer Committee, and sit on the National Advisory Board for Grid Engineering for Accelerated Renewable Energy Deployment.

Q. Have you previously submitted testimony before the Federal Energy Regulatory Commission ("FERC" or the "Commission") in any other proceeding?

A. No. However, I have submitted testimony to the Pennsylvania Public Utility Commission.

II. <u>Purpose and Summary of Testimony</u>

Q. What is the purpose of your testimony in this proceeding?

A. My testimony will address the following issues. <u>First</u>, I will provide a general overview of RECO, its transmission system, and its relationship with its parent company, Orange and Rockland. As part of this discussion, I will also explain how this filing will affect RECO's collection of its PJM related transmission revenue requirement ("TRR"). Second, I will briefly review, here and in Exhibit No. RECO-4, RECO's capital expenditures since 2001, when the Commission approved its current TRR. Third, I will state why RECO is entitled to a 50 basis point ("BP") return on equity ("ROE") adder for participating in the PJM Interconnection ("PJM") Regional Transmission Organization ("RTO").

Q. Was the information in your direct testimony prepared by you or under your supervision?

A. Yes. This testimony was prepared by me or under my supervision. The information presented in my direct testimony represents the work of numerous personnel from various departments of the Company. I have reviewed the data and results and found them to be based on valid assumptions and representative of the Company's financial performance.

Q. Please summarize what RECO is requesting in this filing.

A. As set forth in the direct testimony of the Company's Accounting Panel, RECO is seeking to increase its TRR from its currently stated rate of $11,785,928 to $19,661,232. RECO is also seeking to increase its Schedule 1A charge from $0.2475 per megawatt hour to $0.5351 per megawatt hour.

III. Background of RECO and its Transmission System

Q. Please provide an overview of RECO.

A. RECO, a New Jersey corporation, is an electric only utility that provides electric transmission, distribution, and provider of last resort commodity service to approximately 73,000 customers in an area that extends from eastern Bergen County at the Hudson

River to western Passaic County and small communities in Sussex County, New Jersey. Its service territory consists of the Eastern Division in northeastern and northwestern Bergen County ("Eastern Division"); a Central Division in northern Passaic County ("Central Division"); and a Western Division in northwestern Sussex County ("Western Division"). The Eastern Division is the largest part of RECO's service territory, covering approximately 104 square miles and containing more than 59,000 customers who consume a peak load of approximately 396 MW, or about 90 percent of RECO's total peak load. The peak loads of the Central and Western Divisions represent only approximately 43 MW, or about 10 percent of RECO's total peak load. RECO's retail activities are regulated by the New Jersey Board of Public Utilities ("NJBPU"). RECO's parent, Orange and Rockland, serves more than 225,000 electric and 130,000 gas customers in New York in all of Rockland County, most of Orange County, and part of Sullivan County. Orange and Rockland's retail operations are regulated by the New York Public Service Commission ("NYPSC"). Orange and Rockland and RECO own no electric generating facilities. Orange and Rockland is a subsidiary of Consolidated Edison, Inc. ("CEI"), a New York corporation and exempt public utility holding company under Section 3(a)(1) of the Public Utilities Holding Company Act. CEI is the parent of Con Edison.

Q. Please provide an overview of RECO's transmission system.

A. Collectively, RECO and Orange and Rockland own 547 circuit miles of transmission lines, 77 substations, 86,914 in-service line transformers, 3,840 pole miles of overhead distribution lines, and 2,410 miles of underground distribution lines. Their transmission and distribution facilities are all located in the New York and New Jersey service territories of Orange and Rockland and RECO, respectively.

The transmission lines serving RECO's service territory are a combination of lines that cross the New York and New Jersey border and transmission lines located solely in New Jersey. In 2001, RECO transferred its Eastern Division load from the jurisdiction of the New York Independent System Operator ("NYISO") to that of PJM. The load of the Central and Western Divisions, which are not geographically contiguous to PJM, continue under the jurisdiction of the NYISO. Due to the transfer of the Eastern Division to PJM, several 138 kV, 69 kV, and 34.5 kV feeder elements were added to the PJM-NYISO Tie list, as well as the NYISO Total East Tie list. All RECO facilities deemed transmission pursuant to the FERC Seven Factor Test are considered joint use with Orange and Rockland.

Q. How is the RECO transmission system operated and maintained?

A. Because the RECO and Orange and Rockland transmission systems are interconnected, Orange and Rockland designs and operates them as a single fully integrated system ("Integrated Transmission System") from its control center in Spring Valley, New York. RECO's transmission facilities are operated in accordance with the applicable North American Electric Reliability Corporation ("NERC"), PJM, and Reliability First ("RF") standards. I would note that RECO does not have any operating employees. The transmission lines are maintained by Orange and Rockland's Electric Operations department, including line inspections via bi-monthly aerial patrols and annual ground based foot patrols. Any identified deficiencies and/or damages are repaired according to the priority assigned to the noted issue.

Q. How will this filing affect RECO's transmission rates and the collection of its transmission revenue requirement?

A. As noted above, RECO transferred control of its Eastern Division to PJM in 2001. As part of that transfer, RECO established a separate FERC-approved PJM transmission rate for its Eastern Division, which allows RECO to collect the TRR associated with its Eastern Division from its customers in its Eastern Division. In contrast, RECO's Central and Western Divisions remain part of the NYISO and RECO collects the TRR associated with such Divisions through Orange and Rockland's FERC-approved NYISO transmission rates. By this filing, RECO seeks to update only the PJM transmission rate for its Eastern Division, thereby allowing it to recover the updated TRR associated with its Eastern Division.

Q. Why is RECO seeking to update its TRR and transmission rates?

A. The Company's TRR has not been updated since it was established in 2001. As explained in the next section, since 2001, the Company has continued to invest in transmission infrastructure that is necessary for the provision of safe and reliable electric service to RECO customers. Notwithstanding RECO's and Orange and Rockland's productivity efforts, as described in the testimony of the Company's Accounting Panel, the net increases in costs cannot be absorbed without significantly curtailing or eliminating necessary programs and impairing the Company's ability to cover its cost of capital. Accordingly, the Company is seeking a $7.9 million increase in its TRR and a $0.2876 per megawatt hour increase in its Schedule 1A charge.

IV. RECO's Past System Improvements

Q. Please provide a brief overview of RECO's capital expenditures or capital expenditures on the Integrated Transmission System that benefit RECO since 2001.

A. Since 2001, RECO and Orange and Rockland have implemented a variety of transmission projects to expand and improve the safety, reliability, and capacity of the Integrated Transmission System. Exhibit No. RECO-4 sets forth a list of RECO and Orange and Rockland plant additions over $176.1 million during the period of 2001 through 2016, of which $6.7 million was specific to RECO. The RECO additions enhance the security and reliability of the transmission system while addressing increased operating flexibility in managing the system loading and capacity. RECO will continue to make investments in its transmission system to maintain reliability and in keeping the transmission system operating to RECO's design standard, which requires consideration for the loss of specific transmission elements.

Q. Please briefly describe some of the major transmission projects to expand and improve the safety, reliability, and capacity of the Integrated Transmission System.

A. Some of the projects include:

TRANSMISSION LINE 703 U/G 138kV CORPORATE DRIVE SUBSTATION

The construction of the underground extension to 138kV Lines 702 and 703 provided a transmission source to the Corporate Drive Substation located in Orangeburg, Rockland County, New York. This project also required the construction of an overhead to underground transition structure in Orangeburg. The underground portion of Lines 702 and 703 intercepted original overhead 138kV Transmission Line 702 which ran between the West Nyack Substation, located in West Nyack, Rockland County, New York and the

Harings Corner Substation located in Old Tappan, Bergen County, New Jersey. Approximately 1.86 miles of double circuit 138kV, 3500 KCM, underground transmission conductor was installed. These underground transmission facilities, as well as the Corporate Drive Substation were energized in June 2011. The construction of these transmission and substation facilities allows for improved reliability and service to the residential and commercial customers, including data centers, in the southern Rockland County and northern Bergan County areas.

STERLING FOREST SUBSTATION #67

This project involved the addition of a 175 MVA 138-69kV autotransformer bank, Bank 167, at the Sterling Forest Substation located on Long Meadow Road in the Town of Tuxedo, New York. The new autobank, which was energized in December 2016, is fed from a new 138kV substation yard addition to the original 69 kV Sterling Forest Substation. The new 138kV yard tapped 138kV Transmission Line 26 which originally ran between the Ramapo Substation, located in Rockland County, New York and the Sugarloaf Substation located in Orange County, New York. Line 26 (Ramapo to Sterling Forest) and new Line 261 (Sterling Forest to Sugarloaf) were established with the construction of this new yard at Sterling Forest providing alternate 138kV feeds to the substation. The installation of Bank 167 established a new source into the middle of a long 69kV loop of transmission lines and substations that are between the Sugarloaf and Hillburn Substations. The Wisner, Hunt, Sterling Forest, Lake Road, Blue Lake, Ringwood and West Milford Substations will benefit from improved reliability and voltage support with the installation of Bank 167 and the associated equipment at Sterling Forest.

TL 652 SOUTH MAHWAH - UPPER SADDLE RIVER

The scope of this project was to replace approximately 0.70 miles of 69kV direct buried 1000 KCM aluminum transmission cable between the South Mahwah and Upper Saddle River Substations in Bergen County with new cable in a manhole and duct system. The original direct buried cable, which was installed in 1968, had been damaged by several excavation contractors. In addition, based upon the experience of other utilities the Company concluded that this cable was nearing the end of its anticipated service life. The manhole and duct system for the new 2000 KCM copper cable is concrete encased and is located primarily in public roads. The original direct buried cable was installed primarily on private easements, in residential communities, increasing its exposure to potential dig-ins by landscape and pool contractors. The new cable installation was completed and placed into service in 2003. Placing this project in service improved the reliability of the transmission facilities feeding the Upper Saddle River and Summit Avenue, Substations served by this transmission loop.

SOUTH MAHWAH SUB NEW 138kV TERMINAL

This project included the construction of two new 138kV transmission line terminals for the underground cables required to feed the Darlington Substation. The scope of work included the extension of the existing 138kV bus, the installation of circuit breakers, protective relays, and the associated steel structures to facilitate the required connections to the South Mahwah bus. These facilities, as well as the new Darlington Substation were energized in June 2004. The construction of these transmission and substation facilities allows for improved reliability and service to the residential and commercial customers in the Bergen County areas of Darlington, Mahwah and Ramsey.

TL 61/751 CLOSTER TO CRESSKILL

The Transmission Line 61/751 project included the upgrade of a double circuit 34.5kV wood pole transmission line to 69kV, between the Closter and Cresskill Substations located in Bergen County, as well as an upgrade of the Cresskill Substation. Construction of new double circuit transmission Lines 61 and 751 provided two 69kV transmission sources to the Cresskill Substation. The Company installed approximately 2.3 miles of double circuit 795 ACSR conductor, and an optical ground wire, on new common wood pole structures between these substations. These new transmission facilities, as well as the new Cresskill Substation, were energized in June 2006. The construction of these transmission and substation facilities allows for improved reliability and service to the residential and commercial customers in the Bergen County areas of Cresskill, Closter, and Demarest.

V. Request for ROE Adder For RTO Participation

Q. What transmission incentive is RECO requesting in this filing?

A. RECO is requesting a 50 BP adder for participating in PJM.

Q. Why is RECO entitled to a 50 BP adder for participating in PJM?

A. I am advised by counsel that, pursuant to section 219 of the Federal Power Act and Order No. 679, the Commission has established a 50 BP adder for transmission owners that join, or continue to participate in, an RTO and that have turned over operational control of their transmission facilities to that RTO. The Eastern Division of RECO is a transmission owning member of PJM and has turned over operational control of its transmission assets to PJM. This means that PJM is responsible for transmission access and service, tariff administration, scheduling, and the operation and billing of RECO’s transmission assets. It is my understanding that the Commission has consistently awarded this incentive to all transmission-owning entities that either join, or continue to participate in, an ISO or RTO, including PJM. Accordingly, it is appropriate that RECO receive this incentive.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF NEW YORK)
) **ss**
COUNTY OF ROCKLAND)

I, FRANCIS W. PEVERLY, being first duly sworn on oath depose and say as follows:

The foregoing "Prepared Direct Testimony of Francis W. Peverly on Behalf of Rockland Electric Company" was prepared by me and the other witnesses listed therein, or under the supervision of one or more of such witnesses, and the factual statements contained in such testimony are true and correct to the best of my knowledge, information and belief.

Further affiant saith not.

FW Peverly
Francis W. Peverly

On this 19th day of January 19, 2017, before me, the undersigned notary public, personally appeared Francis W. Peverly and acknowledged to me that he signed the forgoing document voluntarily for its stated purposes. I identified Frank Peverly to be the person whose name is signed on the forgoing document by means of the following satisfactory evidence of identity (check one):

X Identification based on my personal knowledge of his/her identity, or

___ Current government-issued identification bearing his/her photographic image and signature.

JoAnn E. Dagele
Notary Public
My commission expires:

JOANN E. DAGELE
Notary Public, State of New York
No. 01DA6005650
Qualified in Orange County
Commission Expires 4/20/ 2018

EXHIBIT NO. RECO-4

TRANSMISSION SYSTEM
PLANT ADDITIONS GREATER THAN $1.5 MILLION (YEARS 2001-2016)
($millions)

Location	Brief Description	Year in Service	Amount
Orange and Rockland Utilities, Inc.			
MIDDLETOWN TAP SUBSTATION #14	New 345kV-138kV substation	2001	$ 8.1
SHOEMAKER SUBSTATION #11	New transmission 138kV line terminal	2001	5.5
ORANGEBURG SUBSTATION #54	New Transformer Bank 254 and switchgear	2002	2.0
SHOEMAKER SUBSTATION #11	New 138kV-69kV Transformer Bank 811	2005	1.5
TL 11/14 SHOEMAKER - WESTOWN SUB/PORT JERVIS SUB	New double circuit 69kV transmssion line	2006	15.0
TL 531/541 W HAVERSTRAW/N HEMPSTEAD-BURNS	Underground 1.16 miles of 138kV transmission lines	2006	4.4
T/L 601 MONSEY TO BURNS	Upgrade 138kV transmission line to 400 MW capacity	2007	2.1
TL 60 RAMAPO TO TALLMAN	Upgrade 138kV transmission line to 400 MW capacity	2007	3.5
TL 602 TALLMAN TO MONSEY	Upgrade 138kV transmission line to 400 MW capacity	2007	2.9
TL 111 & 14 WESTOWN/SHOEMAKER - PORT JERVIS SUB	New double circuit 69kV transmssion line	2008	13.1
TL 703 U/G 138kV CORPORATE DRIVE SUB	New 138 kV underground transmission line extension	2011	15.1
SUGARLOAF SUBSTATION #110	New 138kV switching station	2011	9.3
RAMAPO SUB #300 & #500	Install new 138kV terminal	2011	4.8
LOVETT SUBSTATION #47	Spare 400/448 MVA Autotransformer	2011	4.2
TL 31/89 HILLBURN - SLOATSBURG	Upgrade transmission line	2011	6.5
TL 26 RAMAPO(300)-SUGARLOAF	Transmission line terminal reconfiguration	2011	2.2
WEST NYACK SUBSTATION #21	Spare 175/196 MVA Autotransformer	2011	2.2
TL 18 RIO - PORT JERVIS SUB	Upgrade transmission line	2011	1.9
TL 702 W NYACK-NY/NJ STATE LINE	New overhead to underground transition yard	2012	7.1
TL 94/Y88 COMMON POLES	Tower modifications	2012	2.0
SUGARLOAF SUBSTATION #108	Transmission modifications	2013	1.9
TL 28 RAMAPO(300)-SUGARLOAF	New 138kV transmission line	2014	24.4
TL 311 HARRIMAN - SLOATSBURG	Upgrade transmission line	2014	4.3
TL 551/562 COMMON POLES	Replace double circuit transmission line structures	2014	3.6
TL 28 RAMAPO(300)-SUGARLOAF	New 345kV transmission line	2015	3.0
STERLING FOREST SUBSTATION #67	138kV transmission line terminals and autobank addition	2016	11.4
SPARE 175MVA TRANSFORMER	Spare 175/196 MVA Autotransformer	2016	1.8
SPARE 400MVA TRANSFORMER	Spare 400/448 MVA Autotransformer	2016	5.6
			$ 169.4
Rockland Electric Company			
TL 652 S MAHWAH) - UPPER SADDLE RIVER	Upgrade 0.70 miles of underground transmission cable	2003	$ 2.0
SOUTH MAHWAH SUB 52,58,59	New 138kV Terminal	2004	3.2
TL 61/751 CLOSTER TO CRESSKILL	Upgrade transmission line from 34.5kV to 69kv	2006	1.5
			$ 6.7

Appendix E

Direct Testimony and Exhibits of Adrian McKenzie

(Exhibit Nos. RECO-5 through RECO-17)

EXHIBIT NO. RECO-5

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Rockland Electric Company	)	**Docket No. ER17-____-000**
	)	

DIRECT TESTIMONY AND EXHIBITS

OF

ADRIEN M. MCKENZIE, CFA

ON BEHALF OF

ROCKLAND ELECTRIC COMPANY

DIRECT TESTIMONY OF ADRIEN M. MCKENZIE, CFA

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

DIRECT TESTIMONY OF
<u>ADRIEN M. MCKENZIE, CFA</u>

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 Street, Austin, Texas, 78751. I am a principal in FINCAP, Inc.

Q2. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A2. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit No. RECO-6.

Q3. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A3. The purpose of my testimony is to present to the Federal Energy Regulatory Commission ("FERC" or "Commission") my independent analysis of a fair return on equity ("ROE") for Rockland Electric Company ("RECO" or the "Company").

Q4. HOW IS YOUR TESTIMONY ORGANIZED?

A4. I first summarize my conclusions and recommendations regarding a fair ROE for RECO. I then present my application of the Commission's two-step Discounted Cash Flow ("DCF") model set forth in Opinion Nos. 531 and 551 to estimate the current cost of equity for a comparable-risk group of other electric utilities.[1]

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[1] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234, *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), *appeals docketed sub nom. Emera Maine v. FERC*, Nos. 15-1118, *et al.* (D.C. Cir. Apr. 30, 2015); *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 (2016), *reh'g pending*.

Consistent with Opinion Nos. 531 and 551, I also examine the cost of equity utilizing a risk premium approach based on Commission-authorized ROEs for electric utilities, the Capital Asset Pricing Model ("CAPM"), and the expected earnings approach. Along with reference to state-allowed ROEs, these three alternative benchmark methodologies were relied on by the Commission in evaluating the placement of the base ROE from within the zone of reasonableness implied by the two-step DCF model,[2] and my evaluation relies on these same factors as well.

Next, I supplement these benchmarks by reference to additional quantitative analyses. While the Commission noted in Opinion No. 551 that Institutional Brokers Estimate System ("IBES") is "the preferred data source for computing the short-term growth rate" for use in its DCF approach,[3] my testimony documents the relevance of growth rates from The Value Line Investment Survey ("Value Line") and presents alternative DCF results as an additional reference point in evaluating a just and reasonable ROE from within the IBES-based DCF zone. In addition, I present the results of a risk premium approach based on Commission-approved ROEs for natural gas pipelines; an application of the empirical CAPM ("ECAPM"), an examination of projected bond yields, as applied to the risk premium, CAPM, and ECAPM approaches; and a DCF analysis based on a select group of low risk non-utility firms.

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[2] Opinion No. 531 at P 146; Opinion No. 551 at P 265.

[3] *Id.* at P 62 (citations omitted).

II. RETURN ON EQUITY FOR RECO

Q5. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A5. This section of my testimony presents my conclusions regarding a fair ROE for RECO. In this regard I discuss the relationship between ROE and the preservation of a utility's ability to attract capital. Next, I summarize my analyses and my recommendation that the base ROE for RECO be set at 10.2%. I then address how an ROE at this level meets the Commission's policy goal of supporting investment in electric transmission infrastructure. Finally, I explain that including an incentive adder to reflect RECO's membership in a regional transmission organization ("RTO') is consistent with Commission policy and precedent.

A. Importance of Regulatory Standards

Q6. WHAT IS THE ROLE OF ROE IN SETTING A UTILITY'S RATES?

A6. 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*[4] and *Hope*,[5] 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.

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[4] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923).
[5] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Q7. WHAT ULTIMATELY GOVERNS THE SELECTION OF A FAIR ROE?

A7. The Commission has recognized that a reasonable point-estimate ROE should be determined based on the facts specific to each proceeding.[6] That point-estimate must also meet the standards mandated by the U.S. Supreme Court.[7] As the Commission reaffirmed in Opinion No. 531: "The Commission's ultimate task is to ensure that the resulting ROE satisfies the requirements of *Hope* and *Bluefield*."[8] This determination requires the Commission to consider all of the available evidence and identify an ROE that is just, reasonable, and sufficient to support RECO'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.

Q8. PLEASE DESCRIBE YOUR UNDERSTANDING OF OPINION NO. 531.

A8. In Opinion No. 531, the Commission adopted a two-step DCF methodology for use in evaluating a just and reasonable ROE for electric utilities.[9] The Commission also recognized that the results of its two-step DCF model were affected by unrepresentative financial inputs related to capital market conditions that were anomalous when compared to the historical record.[10] Considering the potential for DCF results to be distorted and in light of prevailing conditions in

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[6] *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).

[7] *See, e.g.*, *id.* 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).

[8] Opinion No. 531 at P 144.

[9] *Id.* at P 8.

[10] *Id.* at P 145.

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 more recently in Opinion No. 551.[13]

In 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,[14] which are widely employed in regulatory proceedings and utilized in the financial community. These other ROE models and benchmarks are used to gain insight into the effects of anomalous capital market conditions on a point-estimate ROE from within the DCF range of returns.[15]

The alternative benchmarks the Commission considered were (1) a risk premium analysis, (2) a capital asset pricing model ("CAPM") analysis, and (3) an expected earnings analysis.[16] 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.[17] The Commission explained that setting an ROE at a level below the ROEs set by state commissions "would put interstate transmission [investments] at a competitive disadvantage in the capital market in contrast with more conventional electric utility activities."[18]

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[11] *Id.*
[12] Opinion No. 531-B at P 84.
[13] Opinion No. 551 at P 122.
[14] Opinion No. 531 at P 145; Opinion No. 551 at P 122.
[15] *Id*.
[16] Opinion No. 531 at P 147.
[17] *Id.* at P 148.
[18] *Id*. at P 150 (citation omitted).

Q9. DO CUSTOMERS BENEFIT WHEN INVESTORS HAVE CONFIDENCE THAT THE REGULATORY ENVIRONMENT IS STABLE AND CONSTRUCTIVE?

A9. 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 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 to gauge the financial impact of regulatory actions and to advise investors where to put their money. 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.

Q10. WHAT DO YOU MEAN BY "REGULATORY CERTAINTY?"

A10. Regulatory certainty simply means that investors have confidence that prior regulatory actions 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."[19] The Commission's policy efforts focus on constructive and predictable rate regulation and have attracted large commitments

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[19] FERC, *About FERC*, www.ferc.gov/about/about.asp (updated Sept. 30, 2016).

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 in determining a fair ROE.

B. Summary and Conclusions

Q11. WHAT IS YOUR CONCLUSION REGARDING A FAIR ROE FOR RECO?

A11. Based on the results of my evaluation, I recommend a base ROE for RECO of 10.2%. After including a 50 basis point adder to recognize the Company's membership in PJM, the total ROE would be 10.7%.

Q12. PLEASE SUMMARIZE THE RESULTS OF THE COMMISSION'S TWO-STEP DCF ANALYSIS.

A12. The results of my analyses are summarized in Exhibit No. RECO-7. Page 1 of Exhibit No. RECO-7 displays the results of the primary methods relied on by the Commission in Opinion Nos. 531 and 551. In addition to referencing published earnings per share ("EPS") growth estimates from IBES,[20] I also applied the Commission's two-step method using comparable, projected consensus EPS growth rates from Zacks Investment Research ("Zacks"). With respect to the DCF method, I conclude that:

- Application of the two-step DCF methodology based on EPS growth estimates from IBES results in an adjusted ROE zone of reasonableness of 6.28% to 11.19%.
  - The median of the IBES-based DCF results is 8.52%, while the midpoint of the DCF range is 8.74%.

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[20] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters. I obtained these IBES growth rates from http://finance.yahoo.com, which is the recognized source of IBES data used to apply the Commission's DCF method.

    - The midpoint of the upper end of the IBES-based DCF range is 9.85% when the median is used as the measure of central tendency, or 9.96% when central tendency is based on the midpoint.

- Application of the two-step DCF methodology based on Zacks' EPS growth rates in an adjusted ROE zone of reasonableness of 7.05% to 11.19%.
    - The median of the Zacks-based DCF results is 8.65%, while the midpoint of the DCF range is 9.12%.
    - The midpoint of the upper end of the Zacks-based DCF range is 9.92% when the median is used as the measure of central tendency, or 10.15% when central tendency is based on the midpoint.

Q13. WHAT CONCLUSIONS DO YOU REACH REGARDING THE RESULTS OF THE DCF MODEL?

A13. As my testimony explains, the capital market conditions that prompted the Commission to approve an ROE at the middle of the top end of the DCF zone in Opinion Nos. 531 and 551 have continued and impart a downward bias to the results. The Commission has recognized that determining a point-estimate ROE from within the DCF zone is not a mechanical, arithmetic exercise; but instead requires critical evaluation of DCF estimates in light of current capital market conditions and against the results of other methods. My analysis therefore replicates the Commission's use of alternative ROE methodologies to test the results of the DCF model and to inform the determination of a just and reasonable ROE from within the DCF zone. Notably, while the Commission adopted the midpoint of the upper half of the DCF zone in Opinion Nos. 531 and 551, it stated that "The Commission maintains discretion to use its judgment in weighing factors specific to a given proceeding to determine where within the zone of reasonableness the final base ROE should be placed."[21] An ROE from the upper end of the DCF range is consistent with the Commission's recent findings and is warranted in light of a continuation of the capital market conditions characterizing the record periods considered in Opinion Nos. 531 and 551.

Q14. IS THIS CONCLUSION REINFORCED BY YOUR EVALUATION OF ALTERNATIVE ROE METHODS?

A14. Yes. My application of the risk premium, CAPM, and expected earnings methods demonstrates that the median and midpoint values resulting from the Commission's two-step DCF method are far below investors' required return. As summarized on page 1 of Exhibit No. RECO-7:

- Application of the utility risk premium approach based on Commission-approved ROEs for electric utilities implies an ROE point estimate of 10.14%.
- The forward-looking CAPM estimates produce ROE ranges of 7.52% to 11.38% with a median of 8.89% and a midpoint of 9.45%.
- Earned returns for all electric utilities covered by Value Line are expected to average 10.54%; earned returns for the utilities in the proxy group fall in a range of 8.59% to 15.71%, with a median of 11.19% and a midpoint of 12.15%.
- All of these results demonstrate that the median and midpoint values resulting from the Commission's IBES-based two-step DCF method are far too low to be considered reasonable.

Consistent with Opinion Nos. 531 and 551, these alternative methodologies show that the central tendency of the DCF estimates would not produce a just and reasonable end-result, and support an ROE from the upper end of the DCF range of reasonableness.

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[21] Opinion No. 551 at P 277.

Q15. DO STATE-APPROVED ROES ALSO SUPPORT AN ROE FOR RECO WELL ABOVE THE MEDIAN OR MIDPOINT VALUES IMPLIED BY THE COMMISSION'S TWO-STEP DCF MODEL?

A15. Yes. The DCF median and midpoint results fall far short of the median of state-allowed ROEs for integrated utilities authorized during the past 24 months. Meanwhile, data reported to investors by Value Line indicates that the authorized retail service ROEs for the firms in the proxy group range from 9.10% to 10.90%, with a median of 10.28% and a midpoint of 10.00%.

Just as in Opinion Nos. 531 and 551, the significant discrepancy between these state-approved ROEs and the central tendency of the DCF zone "serves as an indicator that an upward adjustment . . . is necessary to satisfy *Hope* and *Bluefield*."[22] This conclusion is reinforced by the Commission's determination that investors in electric transmission infrastructure face increased risks that distinguish these investments from state-regulated companies,[23] and in light of the Commission's policy goal of attracting capital to support expanded investment in interstate electric utility infrastructure.

Q16. WHAT DID YOU CONCLUDE AS TO A FAIR AND REASONABLE BASE ROE FOR RECO?

A16. Based on the results of my analyses, I recommend a base ROE of 10.2% for RECO. The weight of empirical evidence in this case demonstrates the inadequacy of a base ROE equal to the median of the IBES-based or Zacks-based DCF results, which would not conform to the Commission's findings in Opinion

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[22] Opinion No. 531 at P 148.
[23] *Id.* at P 149.

Nos. 531 or 551 or satisfy the *Hope* and *Bluefield* standards.[24] An ROE for RECO from the upper end of the DCF range is supported by consideration of the results of the alternative ROE benchmarks referenced in Opinion Nos. 531 and 551, and is consistent with the continuation of the aberrational capital market conditions recognized by the Commission. An ROE of 10.2% is framed by the results of these alternative benchmarks, and is also warranted in light of 10.32% and 10.57% base ROEs adopted by the Commission in Opinion Nos. 531 and 551. As explained in my testimony, the Company must compete for capital with utilities throughout the nation, including transmission owning members of the ISO New England Inc. ("NETOs") and the Midcontinent Independent System Operator, Inc. ("MISO TOs").

Q17. IS A 10.2% BASE ROE FOR RECO SUPPORTED BY OTHER BENCHMARKS?

A17. Yes. Alternative tests not applied by the Commission in Opinion Nos. 531 and 551 consistently support an ROE in the upper half of the DCF zone, and confirm the reasonableness of a 10.2% base ROE for RECO. The results of these analyses are summarized below, and on page 2 of Exhibit No. RECO-7:

- Application of the two-step DCF methodology based on EPS growth rates from Value Line results in an adjusted ROE zone of reasonableness of 6.52% to 12.81%, a median of 9.66%, and a midpoint of the upper end of the range of 10.64%.
- Reference to the ROEs approved by the Commission for natural gas pipelines implies a current base cost of equity for an electric utility of approximately 10.36%.
- Application of the ECAPM approach results in a zone of reasonableness of 8.40% to 11.60%, with a median of 9.66% and a midpoint of 10.00%.

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[24] The 8.52% and 8.65% medians of my DCF studies are insufficient for the same reasons the Commission rejected DCF midpoints of 9.39% and 9.29% as inadequate in Opinion Nos. 531 and 551, respectively.

- After incorporating projected bond yields, the risk premium, CAPM, and ECAPM methods resulted in median cost of equity estimates ranging from 9.28% to 10.61%.
- DCF estimates for a low-risk group of non-utility firms suggest a cost of equity in the range of 6.24% to 13.46%, with a median of 10.68% and a midpoint of 9.85%.

C. Consistency with Commission Policy Goals

Q18. IS A 10.2% BASE ROE FOR RECO CONSISTENT WITH ESTABLISHED COMMISSION POLICY TO SUPPORT INVESTMENT IN ELECTRIC TRANSMISSION INFRASTRUCTURE?

A18. Yes. The Commission's regulatory actions have been successful in supporting much needed investment in the wholesale transmission grid. Unresponsive, mechanical decision-making that leads to inadequate returns will 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.[25]

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

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[25] Wolfe Research, Utils. & Power, "*FERConomics: Risk to transmission base ROEs in focus*" at 11 (June 11, 2013), http//www.wolferesearch.com/email/x20130610_SF_Trans_ROE.pdf.

certainty in supporting transmission infrastructure investment is as relevant today as ever.

Q19. IF THE COMMISSION WERE TO SET ROES BELOW THE LEVEL INDICATED BY APPROPRIATE BENCHMARKS, WOULD THIS UNDERMINE TRANSMISSION INVESTMENT?

A19. Yes. That risk is very real. As the investment community has recognized, setting the ROE for FERC-jurisdictional transmission operations 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.[26]

More recently, 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."[27] My recommended 10.2% base ROE is appropriate in light of RECO's need to attract capital to transmission infrastructure and the imperative of meeting the *Hope* and *Bluefield* standards.

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[26] *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, U.S. Electric"* at 1 (May 3, 2012)).

[27] Wolfe Research, Utils. & Power, *"Don't you FERCed about ROE, Don't Don't Don't Don't!"* (Apr. 6, 2015).

Q20. HAS THE COMMISSION RECOGNIZED THE IMPORTANCE OF REGULATORY CERTAINTY AND CONSISTENCY IN FOSTERING TRANSMISSION DEVELOPMENT?

A20. Yes. Transparency and stability are important tenets of utility ratemaking and as the Commission has stated, it "strives to provide regulatory certainty through consistent approaches and actions."[28] 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 fair ROE. In Opinion No. 679-A the Commission concluded that "our 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.[29]

D. RECO's Requested ROE Adder is Reasonable

Q21. HAS THE COMMISSION RECOGNIZED THAT AN ROE ADDER FOR PARTICIPATION IN AN RTO IS APPROPRIATE?

A21. Yes. The Commission has repeatedly affirmed its policy of allowing an ROE adder to recognize the consumer benefits provided through membership in an RTO, and noted that a 50 basis point incentive was consistent with the level

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[28] About FERC, *supra* note 19.

[29] *Promoting Transmission Inv. through Pricing Reform*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 69 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,062 (2007).

approved in other proceedings.[30] I support increasing the base ROE by a 50 basis point incentive adder to recognize that RECO will continue to be a member of PJM and its transmission facilities are under the operational control of PJM.

Q22. WHAT ROE IS INDICATED FOR RECO AFTER INCORPORATING THIS INCENTIVE ADDER?

A22. Combining the 50 basis point RTO participation adder with my recommended base ROE of 10.2% produces a total ROE of 10.7%. Because this result falls below the 11.19% upper bound of the DCF range, I concluded that it meets the Commission's policy guidance governing incentive-based ROEs.[31] The upper bounds of the ranges produced by the CAPM and expected earnings analyses also confirm that a total ROE of 10.7% for RECO is within a reasonable range.

III. TWO-STEP DCF ESTIMATES

Q23. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A23. This section presents my application of the Commission's two-step DCF model to estimate the cost of equity. I initially address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe the results of the Commission's two-step DCF model applied to a benchmark group of comparable risk firms.

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[30] *See, e.g., Pepco Holdings, Inc.*, 121 FERC ¶ 61,169 at PP 15-16 (2007); Order No. 679 at P 326 (emphasis added); 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) ("Tariff Equity Coal.") ("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.").

[31] Commission policy requires that the total ROE of a utility including the impact of an incentive must fall within the zone of reasonableness. *See, e.g., Promoting Transmission Inv. through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 93 (2006).

While my recommended base ROE is within the range based on the results of the two-step DCF model approved by the Commission in Opinion Nos. 531 and 551, the alternative benchmarks presented in my testimony provide critical guidance in determining whether an ROE is just and reasonable, and in evaluating a point estimate from within the zone of reasonableness. No single approach provides a fail-safe means to estimate investors' required ROE and it is important to consider the results of alternative methods.

A. Economic Standards

Q24. WHAT ROLE DOES ROE PLAY IN A UTILITY'S RATES?

A24. The ROE compensates investors for the use of their capital to finance the utility's physical plant and assets necessary to provide service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. They will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

Q25. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THIS COST OF EQUITY CONCEPT?

A25. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets; and (2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q26. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A26. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be inferred directly from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on corporate bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q27. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A27. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets—including common stock—required rates of return cannot be directly observed. Yet, there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q28. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A28. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. Following first mortgage bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as subordinated debentures. The last investors in line are common shareholders. They receive only the net revenues, if any, that remain after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q29. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY?

A29. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. Development and Selection of a Proxy Group

Q30. HOW DID YOU IMPLEMENT THE DCF METHOD TO ESTIMATE THE COST OF COMMON EQUITY FOR RECO?

A30. Application of the DCF method, as well as the risk premium and CAPM approaches requires observable capital market data, such as stock prices and beta values. Even for a firm 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 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.

Q31. WHAT SPECIFIC CRITERIA DID YOU RELY ON TO IDENTIFY A PROXY GROUP?

A31. Consistent with the approach adopted by the Commission in Opinion Nos. 531 and 551, I applied 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;
4. Electric utilities that have been assigned corporate credit ratings of BBB+, A-, or A by Standard & Poor's ("S&P"); and
5. Electric utilities that have been assigned long-term issuer ratings of Baa1, A3, or A2 by Moody's Investors Service ("Moody's").

Q32. WHAT WAS THE BASIS FOR THE RANGE OF CREDIT RATINGS USED TO IDENTIFY THE PROXY GROUP?

A32. 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.[32] 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.[33]

RECO has been assigned an S&P corporate credit rating of A-. The BBB+ to A range of S&P credit ratings used to identify the Electric Group is consistent with the one notch higher or lower band under the Commission's guidelines. Meanwhile, Moody's currently rates the Company at A3. Applying the one notch higher or lower band results in a screening criterion based on Moody's long-term issuer ratings of Baa1 to A2. As shown in Exhibit No. RECO-8, application of these screening criteria resulted in a proxy group of eighteen utilities, which I refer to as the "Electric Group."

C. DCF Model

Q33. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF EQUITY?

A33. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on

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[32] Opinion No. 531 at P 107.

[33] *See, e.g., S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 53 (2010), *pet. for review granted in part and denied in part*, 717 F.3d 177 (D.C. Cir. 2013); *Tallgrass Transmission LLC*, 125 FERC ¶ 61,248 at P 77 (2008), *reh'g denied*, 150 FERC ¶ 61,224 (2015).

the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. Thus, the cash flows that investors expect from a stock are estimated, and given current market prices, we can back into the discount rate, or cost of equity, to what investors implicitly used in bidding the stock to that price.

Q34. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A34. 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.

Q35. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF EQUITY?

A35. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[34]

[34] 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.

$$P_0 = \frac{D_1}{k_e - g}$$

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.

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.

Q36. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF COMMON EQUITY?

A36. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

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, the two-step DCF method employs two separate growth rates for each firm, which are then weighted to arrive at a single value for the "*g*" component.

Q38. HOW DID YOU DETERMINE THE DIVIDEND YIELD FOR THE UTILITIES IN YOUR PROXY GROUPS?

A38. An average dividend yield was developed for each electric utility in the proxy group during the six months from July through December 2016. This calculation was 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 used the dividend declared in each month of the analysis period to determine the indicated annual dividend.[35]

Q39. WHAT GROWTH RATE DID YOU USE TO ADJUST THIS CURRENT DIVIDEND YIELD?

A39. Consistency with the assumptions of the Commission's two-step method dictates that the short-term growth rate alone should be used to reflect growth over the coming year, corresponding to the $(1 + 0.5g)$ dividend yield adjustment. The Commission subsequently confirmed that the projected growth rate in nominal Gross Domestic Product ("GDP") should not be considered in adjusting the dividend yield, observing that "the short-term IBES growth rate is far more representative of the growth investors expect over the coming year than is the two-stage growth rate," and concluded that "investors would be unlikely to place

[35] 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.

much weight on a long-term GDP estimate for this purpose."[36] Accordingly, I have adjusted the dividend yield using only the analysts' EPS growth estimate.

Q40. WHAT GROWTH RATES ARE USED IN THE COMMISSION'S TWO-STEP DCF METHOD FOR ELECTRIC UTILITIES?

A40. The first growth rate, which is intended to represent expectations over the short-term, is represented by analysts' EPS growth projections specific to each individual utility in the proxy group. As noted above, the second growth rate is based on long-term forecasts of growth in nominal GDP.

Q41. WHAT WAS THE SOURCE OF THE IBES GROWTH RATES USED IN YOUR APPLICATION OF THE COMMISSION'S TWO-STEP DCF METHOD?

A41. I obtained the IBES earnings growth rates for the utilities in the Electric Group from *Yahoo! Finance*, which has long been accepted and relied on by the Commission in applying the DCF approach. As noted in Opinion No. 531, "the Commission has consistently used IBES growth rate estimates published by *Yahoo! Finance* as the source of analysts' consensus growth rates."[37]

Q42. HOW DID YOU ARRIVE AT YOUR PROJECTED GROWTH RATE IN NOMINAL GDP, REPRESENTING THE SECOND STAGE OF THE COMMISSION'S DCF MODEL?

A42. The Commission has a long history of relying on three independent sources for GDP growth projections in applying the two-step DCF approach in natural gas pipeline proceedings.[38] More recently, the Commission has relied on the long-

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[36] *Seaway Crude Pipeline Co.*, 154 FERC ¶ 61,070 at P 198 (2016).

[37] Opinion No. 531 at P 89.

[38] *See, e.g.*, *Kern River Gas Transmission Co.*, Opinion No. 486-B, 126 FERC ¶ 61,034 at P 130, *order on reh'g*, Opinion No. 486-C, 129 FERC ¶ 61,240 (2009), *order on reh'g*, Opinion No. 486-D, 133 FERC ¶ 61,162 (2010).

term projections of nominal GDP published by IHS Global Insight, the Energy Information Administration ("EIA"), and the Social Security Administration ("SSA"). The Commission affirmed the use of these sources in Opinion No. 531-A.[39]

The calculation of the long-term growth rate in nominal GDP used in my application of the Commission's two-step DCF model is presented on page 3 of Exhibit No. RECO-9. Consistent with the Commission's guidance, I relied on the most recent long-term projections published by IHS Global Insight and the EIA, as well as the SSA forecast over the next 50 years. As shown there, this resulted in an average GDP growth rate of 4.31%.

Q43. WHAT WEIGHTING DID YOU ASSIGN THESE RESPECTIVE GROWTH RATES TO ARRIVE AT THE SINGLE *"G"* COMPONENT OF THE TWO-STEP DCF MODEL?

A43. Following the practice adopted in Opinion No. 531, I weighted the individual analysts' EPS growth rates by two-thirds and the GDP growth projection by one-third to compute a single two-step growth rate for each of the utilities in the proxy groups.

Q44. WHAT WERE THE RESULTS OF YOUR IBES-BASED DCF ANALYSES?

A44. After combining the dividend yields and the weighted average of the IBES and GDP growth projections for each utility, the resulting cost of common equity estimates for the Electric Group are shown on page 1 of Exhibit No. RECO-9. As shown there, these individual DCF estimates ranged from 5.54% to 11.19%.

[39] Opinion No. 531-A at PP 6, 10.

Q45. HOW ELSE DID YOU APPLY THE COMMISSION'S TWO-STEP DCF MODEL TO THE ELECTRIC GROUP?

A45. As shown on page 2 of Exhibit No. RECO-9, I also applied the Commission's two-step DCF model using the projected EPS growth rates published by Zacks.

Q46. IS YOUR REFERENCE TO ZACKS GROWTH DATA CONSISTENT WITH OPINION NOS. 531 AND 551?

A46. Yes. Opinion No. 531 observed that "there may be more than one valid source of growth rate estimates,"[40] and the Commission specifically allowed for "a comparable source" to IBES projections.[41] Opinion No. 531-B further made clear that the Commission had relied on IBES simply because it was the only source of EPS growth rates available for all proxy companies that was presented in that particular record.[42] Opinion No. 551 reiterated the Commission's willingness "to use short-term growth data published by a source comparable to IBES," but clarified its position that "only data sources that publish analysts' consensus growth rates estimates . . . can be considered comparable to IBES."[43] Zacks is a well-recognized source of analysts' estimates that is widely cited in applying the DCF model in regulatory proceedings, and the EPS growth estimates published by Zacks reflect a consensus forecast.

Q47. WHAT WERE THE RESULTS OF YOUR ZACKS-BASED DCF APPLICATION?

A47. After combining the dividend yields and the weighted average of the Zacks and GDP growth projections for each utility, the resulting cost of common equity

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[40] Opinion No. 531 at P 90.
[41] Opinion 531 at P 39.
[42] Opinion No. 531-B at P 76.
[43] Opinion No. 551 at P 64.

estimates are shown on page 2 of Exhibit No. RECO-9. As shown there, these individual DCF estimates ranged from 7.05% to 11.19%.

D. Evaluation of DCF Results

Q48. IN EVALUATING THE RESULTS OF THE DCF MODEL, IS IT APPROPRIATE TO ELIMINATE COST OF EQUITY ESTIMATES THAT ARE UNREASONABLY LOW?

A48. Yes. Consistent with Opinion Nos. 531 and 551, which eliminated reliance on certain low-end outliers, in applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low should be eliminated when evaluating the results of this method.

Q49. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A49. 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 a result, the rate of return that investors require from a utility's common stock, the most junior and risky of a firm'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."[44] The Commission has used 100 basis points above the six-month

[44] Opinion No. 531 at P 122.

average Baa public utility bond yield as an approximation of this threshold, but has also recognized that this is a flexible test.[45]

Q50. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A50. As discussed subsequently, while utility bond yields have declined substantially in response to the Federal Reserve's stimulus policies, widely-referenced forecasts available to investors during the study period support the general expectation for long-term interest rates to rise as the economy and monetary policy return to more normal patterns. As shown in Table RECO-2 below, the most recent forecasts of IHS Global Insight and the EIA imply an average Baa bond yield of 5.82% over the period 2017-2021:

TABLE RECO-2
IMPLIED UTILITY BOND YIELDS

	2017-21
Projected Aa Utility Yield	
IHS Global Insight (a)	4.62%
EIA (b)	5.50%
Average	5.06%
Current Baa - Aa Yield Spread (c)	0.76%
Implied Baa Utility Yield	**5.82%**

(a) IHS Global Insight (Jan. 3, 2017).
(b) Energy Information Administration, Annual Energy Outlook 2016 (Sep. 15, 2016).
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Jul. - Dec. 2016.

[45] *Id*.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip forecast, which projects that yields on corporate bonds will climb on the order of 215 basis points through 2021.[46]

The Commission references a 100 basis point spread over public utility bond as a starting place in evaluating low-end values, but that approach is affected when, as here, anomalously low bond yields do not reflect expectations for the future. As a result, adding a margin of approximately 100 basis points to a six-month historical bond yield average produces a threshold that is too low to reflect investors' required returns going forward. This conclusion is further supported by economic studies that show that risk premiums are higher when interest rates are at very low levels. Under these conditions, the low end of the DCF range is skewed downward, and falls far below what investors require to accept the risks of an equity investment in electric transmission.

Q51. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR THE ELECTRIC GROUP?

A51. Monthly yields on Baa bonds reported by Moody's averaged 4.40% over the six months ended December 2016.[47] As indicated on page 1 of Exhibit No. RECO-9, I eliminated a low-end DCF estimate of 5.54% in evaluating the results of my IBES-based DCF analysis. This DCF values exceeds the historical average yield on Baa-rated utility bonds by only 114 basis points, and falls below the 5.82% Baa yield based on near-term projections. In light of the risk-return tradeoff principle and the test of economic logic applied by the Commission, it is inconceivable that investors are not requiring a substantially higher rate of return

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[46] Wolters Kluwer, *Blue Chip Financial Forecasts*, Vol. 35, No. 12 (Dec. 1, 2016).

[47] Moody's Investors Service, *CreditTrends*.

for holding common stock, which is the riskiest of a utility's securities. As a result, considering that current capital market conditions are not representative and consistent with the upward trend expected for utility bond yields, these values impart a downward bias to the DCF results and should be excluded. Even after these eliminations, retention of a low-end value of 6.28%—which is only 46 basis points above the near-term projected bond yield—still imparts a pronounced downward bias to the DCF results. This is a factor that supports establishment of a base ROE in the upper half of the DCF zone of reasonableness.

Q52. DID YOU EXCLUDE DCF VALUES AT THE HIGH END OF THE RANGE?

A52. No. Under the Commission's two-step DCF model, long-term growth for all of the utilities in the proxy group is assumed to converge to that of the underlying economy. Because this assumption has the effect of significantly moderating the composite growth rate, the Commission noted that "it is unnecessary to screen the proxy group for unsustainable growth rates."[48] As a result, the Commission concluded that the issue of evaluating high-end values is now moot.

Moreover, the upper end of the DCF range was set by a cost of equity estimate of 11.19%. This high-end DCF estimate falls far below the 17.7% threshold formerly referenced by the Commission.[49] Similarly, the 6.77% growth rate underlying this cost of equity estimate is also well below the 13.3% growth rate benchmark that has been used by the Commission to evaluate values at the high end of the DCF range.[50] Accordingly, this cost-of-equity estimate is properly included.

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[48] Opinion No. 531 at P 118.

[49] *See, e.g.*, *ISO New England Inc. v. New England Power Pool*, 109 FERC ¶ 61,147 at P 205 (2004); *So. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 57.

[50] *Id.* at P 57.

Q53. WHAT WERE THE ADJUSTED RESULTS OF YOUR IBES-BASED DCF STUDY?

A53. As shown on page 1 of Exhibit No. RECO-9, after applying the Commission's test for unrepresentative low-end values, the adjusted range of my IBES-based DCF analysis for the Electric Group is 6.28% to 11.19%, with a median value of 8.52% and a midpoint of 8.74%. The upper end midpoint values are 9.85% and 9.96% based on the median and midpoint, respectively.

Q54. WHAT RETURNS WERE INDICATED BY YOUR ZACKS-BASED DCF STUDY?

A54. As shown on page 2 of Exhibit No. RECO-9, the range of Zacks-based DCF values is 7.05% to 11.19%, with a median value of 8.65% and a midpoint of 9.12%. The upper end midpoint values based on EPS growth rates from Zacks are 9.92% and 10.15% based on the median and midpoint, respectively.

IV. SELECTION OF AN ROE WITHIN THE DCF RANGE OF REASONABLENESS

Q55. PLEASE EXPLAIN HOW THE COMMISSION SELECTED AN ROE WITHIN THE RANGE OF REASONABLENESS IN OPINION NOS. 531 AND 551.

A55. In Opinion Nos. 531 and 551, the Commission recognized that the mechanical application of the two-step DCF model could undermine a utility's ability to attract capital for new investment, noting that in that case an ROE based on the measure of central tendency from the two-step DCF results would violate the *Hope* and *Bluefield* standards:[51]

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[51] Opinion No. 531 at P 142; Opinion No. 551 at P 136.

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns established by the two-step constant growth DCF methodology.[52]

The Commission considered a range of evidence, including comparing the results of alternative methods of estimating the cost of equity to those of the two-step DCF model, to determine whether it should apply its traditional policy of setting the ROE at the central tendency (median or midpoint, depending on the situation) of the range of DCF estimates produced for the proxy group. These alternative methodologies demonstrated that, due to the impact of anomalous market conditions on the DCF results, the Commission should depart from its traditional approach and set the ROE at the upper end of the DCF range. In that case, the Commission found that the correct point in the range was the midpoint of the upper end of the DCF range.

Q56. HAVE YOU APPLIED A SIMILAR APPROACH IN THIS CASE?

A56. Yes. I first describe the shortcomings associated with the two-step DCF approach and document the continuation of the capital market conditions cited by the Commission as undermining the ability of the two-step DCF approach to reflect investors' required return. I then apply the same alternative methodologies used by the Commission in Opinion Nos. 531 and 551, which demonstrate that the

[52] Opinion No. 531 at P 41. Application of the two-step DCF method without the midpoint of the upper half of the range adjustment would have resulted in an ROE for the ISO New England Transmission Owners of only 9.39%, a value the Commission found unreasonable. *Id.* at P 142. Similarly, in Opinion No. 551 the Commission concluded that a midpoint ROE of 9.29% was insufficient to satisfy the *Hope* and *Bluefield* standards and could put transmission investment at risk. Opinion No. 551 at PP 136, 263.

ROE should be set in the upper end of the ROE range determined using the DCF results.

A. Shortcomings of the Two-Step DCF Model

Q57. WHAT ARE THE CHALLENGES IN DETERMINING A JUST AND REASONABLE ROE FOR A REGULATED ENTERPRISE?

A57. The actual return investors require is unobservable. Different methodologies have been developed to estimate investors' expected and required return on capital, but all such methodologies are merely 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 meet the requirement to provide investors with compensation commensurate with returns on investments of comparable risk. The DCF method, which the Commission has primarily relied on in setting rates under the statutes it implements, is only one theoretical approach to gain insight into the return investors require; there are numerous other methodologies for estimating the cost of capital and the ranges (or zones) produced by the different approaches can vary widely.

Q58. HAS THE COMMISSION RECOGNIZED THE LIMITATIONS INHERENT IN ITS TWO-STEP DCF MODEL?

A58. Yes. As the Commission observed in Opinion No. 531:

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF

> analyses in determining where to set a public utility's ROE within the range of reasonable returns established by the two-step constant growth DCF methodology.[53]

As the Commission explained, when conditions associated with a model are outside of the 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.[54] In those circumstances, the Commission has "less confidence" that the point of central tendency of the proxy group zone of reasonableness satisfies the standards of *Hope* and *Bluefield*.[55] Accordingly, based on credible evidence in the record of abnormal capital market conditions, the Commission rejected a "mechanical application" of the DCF model and found it necessary to examine evidence of alternative benchmark methodologies and state commission-approved ROEs, "to gain insight into the potential impacts of these unusual capital market conditions."[56] The Commission recently confirmed these conclusions in Opinion No. 551.[57]

These findings were motivated by the Commission's recognition that the paramount consideration that must be reflected in the choice of a point estimate ROE is the need to ensure that the end result meets the standards mandated by the Supreme Court to ensure that a utility can attract capital.[58] This determination requires the Commission to consider the available evidence and identify an ROE that is just, reasonable, and sufficient to support RECO's ability to attract capital

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[53] *Id.* at P 41.

[54] *Id.* at P 145 n.286. Similarly, in Opinion No. 551 the Commission noted that "anomalous market conditions may skew the current outputs of the DCF methodology, such that the mechanical application of the DCF methodology could provide an unjust and unreasonable ROE." Opinion No. 531 at P 131.

[55] Opinion No. 531 at P 145.

[56] *Id.* at P 145.

[57] Opinion No. 551 at P 120.

[58] *Hope*, 320 U.S. at 603; *Bluefield*, 262 U.S. at 693.

and earn a competitive return while serving the policy goal of encouraging investment in transmission infrastructure.

Q59. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH REFERENCING GDP GROWTH IN APPLYING THE DCF MODEL?

A59. 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 firms converge to overall growth in the economy over the very long horizon does not guide investors' views, and growth rates for utilities can and do 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 far 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. While I reference GDP growth in deference to the Commission's decision in Opinion Nos. 531 and 551, there is very clear evidence that this two-step DCF model results in cost of equity estimates that fall far below investors' expectations and violate regulatory standards of fairness.

Q60. HAS THE COMMISSION RECOGNIZED THAT THE RESULTS OF THE TWO-STEP DCF APPROACH ARE NOT NECESSARILY INDICATIVE OF INVESTORS' COST OF EQUITY?

A60. 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.[59] As explained in language from *New Regulatory Finance* that was quoted by the Commission in Opinion Nos. 531-B and 551, "by relying solely on the DCF model at a time when the fundamental assumptions underlying the DCF model are tenuous, a regulatory body greatly limits its flexibility and increases the risk of authorizing unreasonable rates of return. The same is true for any one specific model."[60] The Commission's willingness to consider the results of alternative methods in evaluating where to place the just and reasonable ROE within the DCF-determined zone of reasonableness may ultimately result in a conclusion that satisfies the *Hope* and *Bluefield* standards, but this approach does not eliminate the weaknesses of the two-step DCF model.

Q61. IS THIS CONCLUSION REINFORCED BY YOUR EVALUATION OF ALTERNATIVE ROE METHODS?

A61. Yes. My applications of the risk premium, CAPM, and expected earnings methods demonstrate that the median value resulting from the Commission's two-

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[59] Opinion No. 531 at P 142.

[60] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 28 (2006). The Commission has recognized this as an authoritative source. *See, e.g.*, Opinion No. 531 at PP 145 n.287, 147 nn.289 & 294; Opinion 531-B at P 50 n.107; Opinion No. 551 at P 120.

step DCF method is far below investors' required return. As a result, a fair base ROE from the top end of the DCF zone of reasonableness is warranted.

B. Impact of Capital Market Conditions

Q62. HAS THE COMMISSION ACKNOWLEDGED THE INTER-RELATIONSHIP BETWEEN CAPITAL MARKET CONDITIONS AND A DETERMINATION OF A JUST AND REASONABLE ROE?

A62. Yes. In Opinion Nos. 531 and 551, the Commission determined that capital market conditions were anomalous and that the atypically low interest rates impacted the results of the DCF analysis and led to midpoint results that were too low to be just and reasonable. The Commission considered yields on 10-year constant maturity Treasury bonds as an indicator of a broad range of capital market conditions that affect utilities and the inputs to the DCF model.[61] The Commission explained that:

> Until the financial crisis of 2008, the yield on U.S. Treasury bonds had not fallen below 3 percent since the 1950s. U.S. Treasury bond yields are not an input in the DCF model, but they reflect current capital market conditions, which could have an indirect impact on the two inputs in the DCF model—dividend yield and growth rate.[62]

In addition, as the Commission noted in Opinion No. 531, the record in that proceeding included evidence concerning the implications of Federal Reserve monetary policies and expectations that interest rates would rise significantly over the near-term.[63] As SNL Financial reported to investors, then-Commission Chair LaFleur "stressed that FERC detailed in previous orders the many factors that led the commission to conclude anomalous economic conditions exist, and she

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[61] *See, e.g.,* Opinion No. 531-B at P 49.
[62] Opinion No. 531 at P 145 n.285 (citation omitted).
[63] *Id.* at P 130.

suggested that it would take something more than just a small change in interest rates to change that conclusion."[64]

Q63. HAS THE COMMISSION RECENTLY AFFIRMED THE ONGOING POTENTIAL FOR DCF RESULTS TO BE DISTORTED BY UNUSUAL CAPITAL MARKET CONDITIONS?

A63. Yes. In Opinion No. 551, which was issued in September 2016, the Commission noted that record evidence for the six-month study period ending June 2015 "reflect the type of unusual conditions that the Commission identified in Opinion No. 531."[65] The Commission observed that the yield on 10-year Treasury notes, which had been below two percent in the Docket No. EL11-66 record period, "was at 2.07% during the study period."[66] Opinion No. 551 also cited "unprecedented levels of U.S. Treasury bonds and mortgage-backed securities" on the Federal Reserve's balance sheet as an indicator of the ongoing anomaly, noting that "the Federal Reserve continues to hold approximately $4.25 trillion of those bonds, a level only slightly below record highs."[67] The Commission concluded that, "This record evidence is indicative of the same type of unusual capital market that the Commission found concerning in Opinion No. 531."[68]

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[64] Glen Boshart, *"FERC asked to lower ROE for Duke's Fla. Subsidiary; are more ROE challenges in the offing?"* SNL Financial (Aug. 13, 2014).

[65] Opinion No. 551 at P 122.

[66] *Id.* at P 121.

[67] *Id.*

[68] *Id.*

Q64. HAS THERE BEEN A FUNDAMENTAL SHIFT IN FEDERAL RESERVE MONETARY POLICIES SINCE THE COMMISSION'S DECISIONS IN OPINION NOS. 531 AND 551?

A64. No. The Federal Reserve continues to exert considerable influence over capital market conditions through its massive holdings of Treasuries and mortgage-backed securities. Prior to the initiation of the stimulus program in 2009, the Federal Reserve's holdings of U.S. Treasury bonds and notes amounted to approximately $400 - $500 billion. With the implementation of its asset purchase program, balances of Treasury securities and mortgage backed instruments climbed steadily, and their effect on capital market conditions became more pronounced.

Table RECO-1 below charts the course of the Federal Reserve's asset purchase program:

TABLE RECO-1
FEDERAL RESERVE BALANCES OF
TREASURY BONDS AND MORTGAGE-BACKED SECURITIES
(BILLION $)

2008	$ 458
2009	$ 1,668
2010	$ 1,993
2011	$ 2,501
2012	$ 2,598
2013	$ 3,702
2014	$ 4,211
2015	$ 4,215
2016	$ 4,217

Far from representing a return to normal, the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities continue to exceed $4.2 trillion. The Federal Reserve has announced its intention to maintain these balances by reinvesting principal payments from these securities "until normalization of the level of the federal funds rate is well under way."[69] The Commission recently cited both of these facts as support for its conclusion that mechanical application of the DCF model may produce results that are inconsistent with *Hope* and *Bluefield*.[70]

Q65. DOES THE FEDERAL RESERVE'S DECEMBER 14, 2016 DECISION TO RAISE THE TARGET RANGE FOR THE FEDERAL FUNDS RATE BY ONE-QUARTER PERCENTAGE POINT MARK A RETURN TO "NORMAL" IN THE CAPITAL MARKETS?

A65. No. The Federal Reserve's long-anticipated move to increase the federal funds rate represents its second, modest step towards implementing the process of monetary policy normalization outlined in its September 17, 2014 press release.[71] While the Federal Reserve's action marks a continuation of the normalization process that began with its initial 25 basis point rate rise in the federal funds rate a little more than a year ago, this second move does not result in a fundamental alteration of the anomalous capital market conditions recognized by the Commission in Opinion Nos. 531 and 551. Nor does it remove uncertainty over the trajectory of further interest rate increases or the overhanging implications of the Federal Reserve's enormous holdings of long-term securities. Uncertainties over just how the process of normalizing the Federal Reserve's unprecedented monetary policies will affect capital markets further support the imperative of considering the results of alternative DCF analyses and ROE benchmarks when evaluating a just and reasonable ROE for RECO.

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[69] Press Release, Fed. Reserve, FOMC Statement at 2 (Sept. 21, 2016), http://www.federalreserve.gov/newsevents/press/monetary/20160921a.htm.

[70] Opinion No. 551 at P 121.

[71] Press Release, Fed. Reserve, Policy Normalization Principles and Plans (Sept. 17, 2014), http://www.federalreserve.gov/newsevents/press/monetary/20140917c.htm.

For example, the corollary is that changes to the Federal Reserve's policy of reinvestment would further reduce stimulus measures and could place significant upward pressure on bond yields, especially considering the unprecedented magnitude of the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities. As a *Financial Analysts Journal* article noted:

> Because no precedent exists for the massive monetary easing that has been practiced over the past five years in the United States and Europe, the uncertainty surrounding the outcome of central bank policy is so vast. . . . Total assets on the balance sheets of most developed nations' central banks have grown massively since 2008, and the timing of when the banks will unwind those positions is uncertain.[72]

Similarly, a report from BlackRock cited the potential for yield spikes and the exposure of the utilities sector to rising yields, concluding that, "We are in uncharted territory," when it comes to the implications of unwinding the Federal Reserve's balance sheet holdings.[73] With expectations for higher interest rates, concerns about China's economy, fears over Brexit and the overhanging risk of a global economic slowdown, ongoing concerns over political uncertainty in Washington, and political and economic unrest in the Middle East, the potential for significant volatility and higher capital costs is clearly evident to investors.

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[72] William Poole, "*Prospects for and Ramifications of the Great Central Banking Unwind,*" Financial Analysts Journal (Nov./Dec. 2013).

[73] BlackRock, "When the Fed Yields," *BlackRock Investment Institute* (May 2015).

Q66. HAS THE OUTLOOK FOR INTEREST RATES CHANGED SIGNIFICANTLY SINCE THE COMMISSION FOUND ANOMALOUS CAPITAL MARKET CONDITIONS TO BE PRESENT IN OPINION NOS. 531 AND 551?

A66. No. One of the hallmarks of the anomalous capital market conditions recognized in Opinion Nos. 531 and 551 has been long-term bond yields that are artificially suppressed due to the Federal Reserve's unprecedented intervention in the capital markets. There have been only minor variations in long-term bond yields since the Commission made this determination. Table RECO-4 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 immediately prior to the date of the Commission's Opinion No. 531 and in September 2016:[74]

TABLE RECO-4
COMPARISON OF YIELD BENCHMARKS

	(a) Baa Utility		(b) 30-Yr Treasury		(b) 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
Dec. 2016	4.40%	-22	2.55%	-45	1.85%	2
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
Dec. 2016	4.40%	-25	2.55%	-17	1.85%	-22

(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.

[74] The changes referenced in Table RECO-4 are basis point changes relative to the values for the respective record periods corresponding to Opinion Nos. 531 and 551.

As illustrated above, these benchmarks indicate that conditions remain congruous with those prevailing during the evidentiary periods considered in Opinion Nos. 531 and 551. Yields on Treasury bonds are equal to or below those prevailing during the periods characterized by the Commission as anomalous. Average 10-year Treasury bond yields for the study period remain below the 2.00% threshold highlighted by the Commission,[75] and are hardly comparable to historical levels.[76] In late 2014, when 10-year Treasury bond yields were approximately 50 basis points higher than present levels, former Federal Reserve President Charles Plosser observed that U.S. interest rates were unprecedentedly low, and "outside historical norms."[77]

As the Commission recently concluded, "evidence in the record regarding historically low interest rates and Treasury bond yields as well as the Federal Reserve's large and persistent intervention in markets for debt securities are sufficient to find that current capital market conditions are anomalous."[78] My testimony demonstrates that these facts are unchanged, which supports a continuation of the Commission's findings regarding the need to consider the results of alternative benchmarks and fix an ROE in the upper end of the DCF zone of reasonableness.

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[75] Opinion No. 531 at P 145 n.285; Opinion No. 551 at P 121.

[76] For example, over the 1968-2015 period 10-year Treasury bond yields averaged 6.65%.

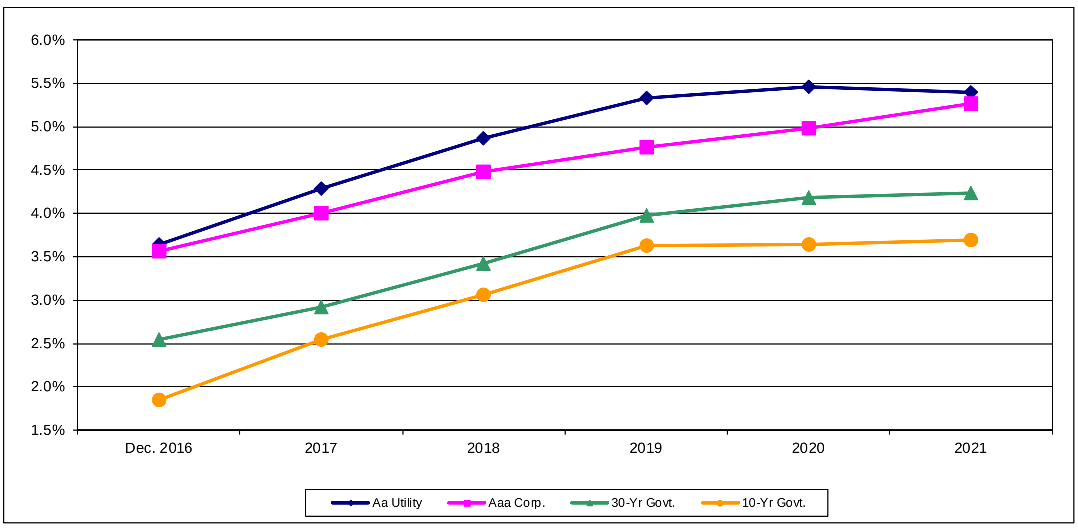
[77] Katy Barnato & Carolin Roth, *"Fed's Plosser: Low rates 'should make us nervous',"* CNBC (Nov. 11, 2014), http://www.cnbc.com/2014/11/11/feds-charles-plosser-there-are-many-indicators-that-tell-us-rates-are-too-low.html.

[78] Opinion No. 551 at P 124.

Q67. IS THERE EVIDENCE THAT INVESTORS CONTINUE TO ANTICIPATE SIGNIFICANTLY HIGHER INTEREST RATES IN THE FORESEEABLE FUTURE?

A67. Yes. Figure RECO-1 compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with the average of near-term projections from Value Line, IHS Global Insight, Blue Chip Financial Forecasts, and the Energy Information Administration ("EIA"):

FIGURE RECO-1
INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Dec. 2, 2016)
IHS Global Insight (Jan. 3, 2017)
Energy Information Administration, Annual Energy Outlook 2016 (Sep. 15, 2016)
Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 12 (Dec. 1, 2016)

These forecasting services are highly regarded and widely referenced, with the Commission incorporating forecasts from IHS Global Insight and the EIA in its two-step DCF model. The upward trajectory of projected interest rates over the near-term continues to confirm the Commission's determination that the current low interest rate environment is, indeed, abnormal.

Q68. DOES THE FACT THAT THESE PROJECTIONS HAVE NOT YET MATERIALIZED ALTER INVESTORS' GENERAL EXPECTATION

THAT INTEREST RATES WILL RISE SUBSTANTIALLY IN THE NEAR-TERM?

A68. No. The fact that past forecasts of higher interest rates have not come to fruition does not alter investors' general expectation that interest rates will rise substantially in the near-term future. Just as the Commission relies on the forecasts of IHS Global Insight and the EIA as a guide to long-term expectations for growth GDP, these same sources provide evidence of investors' expectations for the future course of bond yields. While the actual pattern of bond yields may not track precisely with these near-term forecasts, they provide an objective, well-recognized guidepost to investors' future expectations. As the Commission observed in Opinion No. 531, "the cost of common equity to a regulated enterprise depends upon what the market expects, not upon what ultimately happens."[79]

Q69. HOW MIGHT THE FACTORS YOU DESCRIBE TRANSLATE INTO DOWNWARD-BIASED DCF ESTIMATES?

A69. A collateral consequence of anomalous capital market conditions is their impact on the screening of DCF results. The Commission's policy is to eliminate low-end DCF estimates that do not exceed average Baa public utility bond yields by approximately 100 basis points or more. As discussed above, current low interest rates reflect the legacy of the Great Recession and the Federal Reserve's stimulus policies. As illustrated in Figure RECO-1, these low historical interest rates do not reflect expectations for the future, which is the only relevant consideration when evaluating investors' required return. As a result, adding a margin of approximately 100 basis points to historical bond yields produces a threshold that

[79] Opinion No. 531 at P 88.

is too low to reflect investors' required returns going forward. This conclusion is further supported by economic studies discussed later in my testimony that show that risk premiums are higher when interest rates are at very low levels. Under these conditions, this static test of low-end outliers based on historical public utility bond yields retains low-end DCF estimates that are far below what investors require to accept the risks of an equity investment in electric transmission facilities, including those of RECO.

To address the reality of current capital markets, it is imperative that the Commission consider current capital market conditions and near-term forecasts for public utility bond yields when testing low-end DCF estimates and evaluating a fair ROE for RECO from within the zone of reasonableness. Furthermore, interest rates are historically low because of Federal Reserve policies designed to address underlying uncertainties and risks in the economy. This, in turn, increases the importance of recognizing the expansion of the risk premium in the current low-rate environment.

Q70. WHAT OTHER EVIDENCE INDICATES THAT CURRENT CAPITAL MARKET CONDITIONS UNDERMINE THE RELIABILITY OF THE TWO-STEP DCF RESULTS?

A70. Apart from the direct effect on the evaluation of low-end values, empirical evidence also indicates that the results of the Commission's DCF model are distorted by current capital market conditions. The DCF method is only one theoretical approach to gain insight into the return investors require, which is unobservable. While the restrictive assumptions of the DCF model boils this determination down to the familiar dividend yield and growth rate components, this masks the underlying complexities that accompany any attempt to distill every facet of investors' expectations into a single growth estimate. Recognizing the frailties associated with a mechanical reliance on a rote application of the DCF method, the Commission has stressed the need to carefully evaluate DCF results against a number of well-accepted benchmarks to ensure that the *Hope* and *Bluefield* standards are met.

Q71. IS IT POSSIBLE TO PINPOINT THE EXACT MECHANISM BY WHICH CAPITAL MARKET CONDITIONS ARE TRANSLATED INTO UNREPRESENTATIVE INPUTS AND DOWNWARD-BIASED DCF ESTIMATES?

A71. No. Based on a series of very restrictive assumptions, DCF theory reduces the actions, opinions, and expectations of all investors down to a dividend yield and growth component, with the only observable parameter being the market price of the stock. There is no direct link between this model and bond yields (historical, current, or expected), Federal Reserve policies, relative risk perceptions, or any other data input from the capital markets or the economy. Similarly, the Commission concluded in Opinion No. 551 that "a direct causal analysis linking specific capital market conditions to particular inputs or assumptions of the DCF model is not necessary."[80] As a result, while we can observe the end-result of our best attempt to apply the DCF model in a way that mirrors investors' expectations, there are many exogenous factors that ultimately influence DCF estimates. But as the Commission has recognized, this does not absolve DCF values from critical evaluation, both against observable benchmarks such as bond yields and the results of other methods and approaches, and most importantly, the *Hope* and *Bluefield* standards.

[80] Opinion No. 551 at P 125.

In my opinion, the Commission should consider alternative methods and ROE benchmarks in all conditions and in all cases, because the DCF model—like any model—faces model risk and is not infallible. The Commission's reduced confidence in the central tendency of the DCF results is particularly appropriate, however, when unrepresentative capital market conditions undermine the ability of the DCF approach to reasonably reflect investor expectations.[81] To address the reality of current capital markets, it is imperative that the Commission consider current capital market anomalies and near-term forecasts for public utility bond yields when testing low-end DCF estimates and when evaluating a fair ROE for RECO from within the zone of reasonableness.

C. Risk Premium Approach – FERC ROEs

Q72. BRIEFLY DESCRIBE THE RISK PREMIUM APPROACH.

A72. The risk premium approach 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 current 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 observable bond yields.

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[81] *See, e.g.,* Opinion No. 551 at P 125; Opinion No. 531-B at P 71; Opinion No. 531 at P 39.

Q73. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A73. Yes. The risk premium approach 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 provides an important tool in estimating a fair ROE for RECO.

Q74. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE MERITS OF THIS RISK PREMIUM APPROACH?

A74. Yes. The Commission has previously considered evidence of alternative ROE benchmarks in evaluating a fair ROE, including the risk premium approach.[82] Most recently, 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.[83] I am recommending the same approach in this proceeding.

Q75. HOW DID YOU IMPLEMENT THE RISK PREMIUM APPROACH?

A75. As in Opinion Nos. 531 and 551, I based 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

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[82] *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 imputs [*sic*] and factors that the respective witnesses employed.").

[83] Opinion No. 531 at P 146; Opinion No. 551 at P 191.

costs. The Commission has also recognized the importance of considering state authorized returns in evaluating a fair ROE for FERC-jurisdictional transmission operations.[84] Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q76. HOW DID YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED ROES?

A76. I applied 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 which was relied on by the Commission in its evaluation of a fair ROE in Opinion Nos. 531 and 551.[85] On page 3 of Exhibit No. RECO-10, 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 2016. As shown there, these equity risk premiums for electric utilities averaged 4.84%, and the yield on public utility bonds averaged 5.71%.

Q77. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A77. 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

[84] Opinion No. 531 at PP 145, 150; Opinion No. 551 at P 250.
[85] Opinion No. 531 at PP 146-47; Opinion No. 551 at P 191.

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.

Q78. HAS THIS INVERSE RELATIONSHIP BEEN DOCUMENTED IN THE FINANCIAL RESEARCH?

A78. Yes. This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature.[86] For example, *New Regulatory Finance* documented this inverse relationship:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates—rising when rates fell and declining when rates rose.[87]

Other regulators have also recognized that the cost of equity does not move in tandem with interest rates.[88] 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."[89]

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[86] *See, e.g.*, E. F. Brigham, D.K. Shome & S.R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Fin. Mgmt.* (Spring 1985); R.S. Harris & F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Fin. Mgmt.* (Summer 1992).

[87] Morin, New Regulatory Finance, *supra* note 68, at 128.

[88] *See, e.g.*, *Application of Southern Cal. Edison Co. (U338E) for Authorized Cost of Capital for Util. Operations for 2008*, D. 08-05-035, 2008 Cal. PUC LEXIS 204 (CPUC May 29, 2008); Entergy Mississippi Inc., No. 2014-UN-132, Formula Rate Plan FRP-5 (revised Mar. 2010), http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf.

[89] Opinion No. 531 at P 147.

Q79. WHAT ARE THE IMPLICATIONS OF THIS RELATIONSHIP UNDER CURRENT CAPITAL MARKET CONDITIONS?

A79. Given that bond yields have remained uncharacteristically low and that equity risk premiums move inversely with interest rates, there is an implied sharp 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.

Q80. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM METHOD USED IN OPINION NO. 531?

A80. I conducted 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 6 of Exhibit No. RECO-10, the equity risk premium for electric utilities increased approximately 68 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. RECO-10, with an average six-month historical yield on Baa public utility bonds at December 2016 of 4.40%, this implied a current equity risk premium of 5.74% for electric utilities. Adding this equity risk premium to the average six-month historical yield on Baa utility bonds implies a current cost of equity of 10.14%.

D. Capital Asset Pricing Model

Q81. PLEASE DESCRIBE THE CAPM.

A81. The CAPM approach is generally considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM 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
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an ex-ante, or forward-looking, model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data. In contrast to applications of the CAPM using historical, realized rates of return (an approach that was explicitly rejected in Opinion No. 531), my CAPM analysis incorporates forward-looking expectations that are consistent with the assumptions of this approach.

Q82. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A82. I used the same approach considered by the Commission in establishing a fair ROE in Opinion Nos. 531 and 551.[90] This application of the CAPM to the Electric Group, based on a forward-looking estimate for investors' required rate of return from common stocks, is presented on Exhibit No. RECO-11. In order to

[90] Opinion No. 531 at P 146; Opinion No. 551 at PP 165-70.

capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

I obtained the dividend yield for each firm from Value Line. The growth rate is equal to the average of the earnings per share growth projections for each firm published by IBES, with each firm'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 8.9%. Combining this average growth rate with a year-ahead dividend yield of 2.5% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 11.4%. Subtracting a 2.6% risk-free rate based on the six-month average yield on 30-year Treasury bonds at December 2016 produces a market equity risk premium of 8.8%.

Q83. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A83. I relied 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 beta provides a good predictor of future stock price behavior relative to the market. As noted in *New Regulatory Finance*:

> 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. . . . 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.[91]

The fact that investors rely on Value Line betas in evaluating expected returns for utility common stocks provides strong support for this approach.

Q84. DID YOU INCLUDE A SIZE ADJUSTMENT IN APPLYING THE CAPM?

A84. Yes. Because financial research indicates that the CAPM 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.[92]

According to the CAPM, 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, size premiums have been developed to account for the level of a firm's market capitalization in determining the cost of equity.[93] Likewise, my CAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the firms in the Electric Group.

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[91] Morin, New Regulatory Finance, *supra* note 68, at 71.

[92] Morningstar, 2015 Ibbotson SBBI Classic Yearbook, at 99.

[93] Roger J. Grabowski, James P. Harrington, Carla Nunes & Duff & Phelps, 2016 Valuation Handbook – Guide to Cost of Capital (Preview Version) (John Wiley & Sons 2016).

Q85. WHAT ROE IS IMPLIED USING THE CAPM APPROACH?

A85. As shown on page 1 of Exhibit No. RECO-11, after adjusting for the impact of firm size, the forward-looking CAPM approach implied a cost of equity range of 7.52% to 11.38% with a median cost of equity of 8.89% for the Electric Group. The midpoint of the CAPM range was 9.45%.

E. Expected Earnings Approach

Q86. PLEASE EXPLAIN YOUR EXPECTED EARNINGS STUDY?

A86. Consistent with Opinion Nos. 531 and 551, I also evaluated the ROE by reference to expected rates of return for electric utilities. 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.[94]

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

[94] Opinion No. 531 at P 147.

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 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.

Q87. HOW IS THE COMPARISON OF OPPORTUNITY COSTS TYPICALLY IMPLEMENTED?

A87. The traditional comparable earnings test 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 is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (e.g., Value Line). 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. My application of the expected earnings approach was focused exclusively on forward-looking projections, not historical data.

Q88. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR ELECTRIC UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A88. Value Line reports that its analysts anticipate an average rate of return on common equity for the firms included in its electric utility industry groups of 10.54% over its 2019-2021 forecast horizon.[95] Meanwhile, for the firms in the Electric Group specifically, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit No. RECO-12. 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.[96] Accordingly, consistent with the Commission's findings and the theory underlying this approach, I made an adjustment to compute an average rate of return.[97] As shown on Exhibit No. RECO-12, Value Line's projections for the Electric Group resulted in an adjusted range of expected rates of return from 8.59% to 15.71%, with a median of 11.19% and a midpoint of 12.15%.

F. State-Approved ROEs

Q89. HOW DO THE DCF MEDIAN VALUES COMPARE WITH THE RESULTS OF YOUR ANALYSIS OF STATE ROE DETERMINATIONS REPORTED BY RRA?

A89. The IBES and Zacks-based median values fall below any ROE authorized by state regulators for electric utilities during the 24 months ending September 30, 2016,

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[95] The Value Line Investment Survey (Oct. 28, Nov. 18, and Dec 16, 2016).

[96] *So. Cal. Edison Co.*, 92 FERC ¶ 61,070 at 61,263 & n.38.

[97] Use of an average return in developing the rate of return is well supported. *See, e.g.*, Morin, New Regulatory Finance, *supra* note 68, at 305-06, which discusses the need to adjust Value Line's end-of-year data, consistent with the Commission's prior findings.

which are shown on page 1 of Exhibit No. RECO-13. With respect to state-allowed ROEs for integrated utilities, which the Commission relied on in Opinion Nos. 531 and 551,[98] a review of RRA data for the past two years indicates that approximately 68% of these decisions fell in the 9.60% to 10.30% range, with the median and midpoint being 9.74% and 9.80%, respectively.

Q90. WHAT CONCLUSIONS TO DO YOU DRAW FROM YOUR ANALYSIS OF STATE ROE DECISIONS?

A90. As the Commission recently concluded, "investing in . . . Commission-regulated electric transmission entails risks that are 'at least as great' as those faced by investors in integrated electric utilities."[99] My analysis shows a meaningful differential between the DCF median values, relative to the central tendency of base ROEs authorized in the most recent 24 months by state regulatory commissions for integrated electric utilities. This differential strongly suggests that the central tendency of the IBES-based and Zacks-based DCF results would be insufficient to enable RECO to attract and retain equity capital in competition with other investments of comparable risk.

Q91. WHAT ARE THE STATE-APPROVED ROES FOR THE ELECTRIC GROUP?

A91. As shown on page 3 of Exhibit No. RECO-13, the state-approved ROEs reported to investors by Value Line for the utilities in the Electric Group fell in a range of 9.10% to 10.90%, with a median of 10.28% and a midpoint of 10.00%. As noted earlier, the investment community has recognized that fixing the ROE for FERC-

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[98] The state commission authorized ROEs referenced in Opinion No. 531 corresponded to those for integrated electric utilities. Opinion No. 531 at P 148 (citing Exh. NET-400 at 26-27, *supra* note 26); *see also* Opinion No. 551 at P 250.

[99] Opinion No. 551 at P 250 (citation omitted).

jurisdictional utilities below the level allowed by state commissions would undermine the ability of transmission operations to compete for capital. Similarly, the Commission recently concluded that "as in Opinion No. 531, we find that the potential for reduced transmission investment counsels against a mechanical application of the DCF."[100] An ROE from the top end of the DCF zone of reasonableness is appropriate in light of the need to meet established regulatory standards and attract capital to support interstate electric utility infrastructure.

G. Evaluating a Just and Reasonable ROE within the DCF Range

Q92. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR ALTERNATIVE BENCHMARK STUDIES?

A92. As demonstrated above, the capital market conditions that characterized the record in Opinion Nos. 531 and 551 are ongoing and the median values of the IBES-based and Zacks-based DCF results falls far below state ROEs, and thus below the ROE necessary to meet the requirements of *Hope* and *Bluefield.* While the Commission's reliance on the midpoint of the upper half of the IBES-based DCF zone to establish the ROE in Opinion No. 531 was consistent with the record evidence in those proceedings, the Commission made clear that the evaluation of a just and reasonable ROE from within the range of reasonable returns would depend on case specific evidence.[101]

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[100] Opinion No. 551 at P 263.

[101] *See, e.g.,* Opinion No. 531 at P 151 n.306.

Q93. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING A JUST AND REASONABLE ROE FOR RECO FROM WITHIN THE DCF RANGE?

A93. As indicated on page 1 of Exhibit RECO-9, using the median of the IBES-based DCF results as the measure of central tendency implies an upper-end midpoint of 9.85%. This compares with ROEs of 10.57% and 10.32% under the midpoint approach adopted by the Commission in Opinion Nos. 531 and 551. In fact, the 9.85% upper-end midpoint calculated against the IBES-based DCF median in this proceeding is only about 60 basis points greater than the midpoint values rejected in Opinion Nos. 531 and 551 as insufficient to meet the *Hope* and *Bluefield* standards.

Q94. WOULD SUCH AN OUTCOME BE CONSISTENT WITH ECONOMIC OR REGULATORY STANDARDS?

A94. No. The Commission has recognized that a reasonable point-estimate 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.[102]

The paramount consideration that must be reflected in the choice of a point estimate is the need to ensure that the end result meets the standards mandated by the Supreme Court 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 and identify an ROE that is

[102] *Midwest ISO*, 106 FERC ¶ 61,302 at P 8.

just, reasonable, and sufficient to support the Commission's goal of encouraging investment in wholesale utility infrastructure.

Q95. WOULD IT MAKE SENSE TO RELY ON THE MEDIAN IN EVALUATING AN ROE FROM THE UPPER END OF THE ZONE OF REASONABLENESS IN THIS CASE?

A95. No. A mechanical policy of referencing only the median of the DCF estimates when evaluating a just and reasonable ROE for a single transmission owner leaves the Commission with little flexibility when the result fails to reflect a fair and reasonable ROE. 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 RECO with other opportunities, there is no reason to believe that investors would distinguish between utilities where the ROE applicable to FERC-jurisdictional transmission service is established on a stand-alone basis and those that are subject to a single, RTO-wide ROE determination (e.g., the NETOs and MISO TOs).

In fact, capital markets are highly sophisticated and RECO 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 the DCF 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. Similarly, in approving the use of a national proxy group over a regional proxy group, Opinion No. 531 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.[103]

The objective of the Commission's evaluation is not to arbitrarily balkanize transmission utilities based on an artificial distinction between those that are subject to a unified, RTO-wide ROE and those cases that involve a single utility, such as RECO. Rather, it is to consider the risk perceptions and requirements of actual investors in the capital markets, who do not determine their required returns for transmission 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 noted above, a mechanical policy of referencing the median when establishing an ROE from the upper end of the DCF zone would understate the ROE for RECO relative to the result implied by the approach adopted in Opinion Nos. 531 and 551.

Q96. ARE THERE DIFFERENCES IN RISKS OR CAPITAL MARKET CONDITIONS THAT WOULD JUSTIFY A DRAMATIC REDUCTION IN THE ROE?

A96. No. The comparable risk bands used to identify the proxy groups adopted in Opinion Nos. 531 and 551 encompass the range of ratings for the Electric Group. Meanwhile, as shown in Exhibit No. RECO-8, the average S&P and Moody's credit ratings for the Electric Group are A- and Baa1, respectively. The average S&P credit rating of A- for the Electric Group is one notch above that of the proxy

[103] Opinion No. 531 at P 96 (footnotes omitted).

group used by the Commission in Opinion No. 531.[104] Similarly, the average S&P and Moody's credit ratings for the proxy group used in Opinion No. 551 were BBB+ and Baa1, respectively,[105] which are also comparable to those corresponding to the Electric Group. Meanwhile, as indicated in Table RECO-2, utility bond yields are generally comparable to those underlying Opinion Nos. 531 and 551. As a result, there are no distinctions in risk or capital market conditions that would support a significant downward adjustment to the ROE in this proceeding, relative to the findings in Opinion Nos. 531 and 551.

Q97. WHAT ARE THE IMPLICATIONS FOR THE COMMISSION'S POLICY OF ENCOURAGING CONTINUED GRID INVESTMENT?

A97. As noted earlier, investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. If the utility is unable to offer a return similar to that available from other opportunities, investors will become unwilling to supply the capital on reasonable terms. In evaluating an investment in the transmission sector of the electric power industry, investors will naturally seek to maximize their expected rate of return for a given level of risk. Awarding a downward-biased ROE by mechanically applying a particular formula based on the median would put utilities such as RECO at a disadvantage, relative to the NETOs and MISO TOs.

It is only rational for potential investors to consider the current regulatory treatment afforded to transmission owners such as RECO in evaluating whether or

[104] *Coakley v. Bangor Hydro-Elec. Co.*, Docket No. EL11-66-001, Exh. NET-701, Credit Ratings (Apr. 6, 2013). Data regarding Moody's credit ratings was not contained in the record evidence in that proceeding.

[105] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Docket No. EL14-12-002, Exh. S-5 at 3-4 (July 27, 2015).

not to commit new capital, and at what cost. Adopting a mechanical policy that effectively imposes an ROE penalty in proceedings involving a single utility would be a disincentive to invest in RECO and similarly situated utilities.

Q98. BASED ON THE EVIDENCE PRESENTED ABOVE, WHAT IS YOUR RECOMMENDED ROE FOR THE COMPANY?

A98. Based on the results of my analyses, I recommend a base ROE for RECO of 10.2%. An ROE of 10.2% is framed by the results of the same alternative ROE benchmark approaches referenced by the Commission in evaluating a just and reasonable ROE from within the upper end of the DCF zone of reasonableness. My recommendation considers the continuation of the aberrational capital market conditions cited in Opinion No. 531, as well as the need to provide RECO with an ROE that is consistent with recent determinations for other FERC-jurisdictional transmission owners.

V. OTHER ROE BENCHMARKS

Q99. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A99. This section presents alternative tests to demonstrate that my recommended ROE based on the ROE analyses discussed earlier is reasonable and does not exceed a fair ROE given the facts and circumstances that apply to RECO. Specifically, I test my recommended ROE for the Company against a series of relevant benchmarks that measure the cost of equity based on: (1) application of the Commission's two-step-DCF approach using EPS growth rates from Value Line; (2) Commission-approved ROEs for natural gas pipelines; (3) application of the ECAPM approach; (4) projected bond yields, as applied to the risk premium, CAPM, and ECAPM approaches; and (5) a DCF analysis based on a select group of low risk non-utility firms. These other benchmarks provide additional guidance that is relevant in corroborating my recommendation based on the end-result of the primary methods discussed previously.

A. Value Line-Based DCF Study

Q100. THE COMMISSION DECLINED TO ADOPT A DCF ANALYSIS USING VALUE LINE GROWTH RATES IN OPINION NO. 551.[106] WHY ARE YOU CONTINUING TO REFERENCE THIS APPROACH?

A100. While I believe that Value Line EPS growth rates represent a comparable source to IBES that should be used directly in applying the DCF model, I am not proposing that the Commission do so in this proceeding. Instead, my reference to the Value Line-based DCF results is only as another informative benchmark, which recognizes Value Line's relevance as a guide to investors' expectations,[107] as well as the advantages associated with its projections.[108] Rather than establishing the DCF zone of reasonableness and point estimate ROE directly on the Value Line-based DCF results, I am proposing this approach only as an additional check of reasonableness to guide the placement of the just and reasonable ROE from within the zone of reasonableness.[109]

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[106] Opinion No. 551 at P 62.

[107] Morin, New Regulatory Finance, *supra* note 68, at 71, (noting 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.").

[108] *E.g.,* Value Line estimates are supported by complete and transparent analyses which are updated on a consistent schedule and based on a common analytical framework maintained and administered by Value Line's research department.

[109] *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." Morin, New Regulatory Finance, *supra* note 68, at 300.

Q101. WHAT WERE THE RESULTS OF YOUR VALUE LINE-BASED DCF APPLICATION?

A101. After combining the dividend yields and the weighted average of the Value Line and GDP growth projections for each utility, the resulting cost of common equity estimates are shown on Exhibit No. RECO-14. As shown there, these individual DCF estimates ranged from 6.52% to 12.81%, with a median of 8.48%. The middle of the upper end of the Value Line-based zone based on the median is 10.64%. This confirms my conclusion that an ROE of 10.2% from the upper end of the IBES-based DCF zone of reasonableness is warranted for RECO.

B. Gas Pipeline ROEs

Q102. DO NATURAL GAS PIPELINE RETURNS PROVIDE A MEANINGFUL BENCHMARK TO EVALUATE A FAIR BASE ROE FOR THE COMPANY?

A102. Yes. While I recognize that in Opinion No. 531 the Commission elected not to compare electric utilities directly to natural gas pipelines when determining ROE, I believe the comparison is relevant. For example, in *Williston Basin*, FERC staff proposed expanding the proxy group used to estimate the cost of equity for gas pipelines to include utilities with electric utility operations, noting that investors "see a linkage between the risk profile of different types of utilities," and concluding that:

> [G]as pipelines and transmission facilities for electricity have characteristics in common in that both transmit a product with time and weather-sensitive demand profiles over rights-of-way that are capital intensive and relatively inflexible. Expanding the gas pipeline proxy group to include publicly-owned companies engaged in other regulated lines of energy-related business will, in

> my opinion, increase the level of confidence in the reasonableness of the results of my DCF analysis . . . .[110]

Staff's arguments were ultimately persuasive, as the Commission subsequently adopted a proxy group of natural gas pipeline companies that also included firms with substantial electric utility operations. This is consistent with the Commission's recent findings that distinctions between the gas pipeline and electric utility industries have moderated significantly due to changes to the electric utility industry.[111]

At the same time, the Commission previously has also rejected using DCF analyses for natural gas pipelines in establishing a fair ROE for electric utility operations because of differences between the two industries. In *Southern California Edison Co.*, the Commission stated that it was not appropriate to consider returns in the natural gas industry when evaluating electric utilities because "the electric industry is just beginning a significant new phase of its restructuring."[112] Fifteen years have passed since this statement was made, however, and as noted above, the Commission recognized in Opinion No. 531 that the electric industry and its restructuring have matured, which confirms that reference to gas company ROEs is relevant.[113]

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[110] *Williston Basin Interstate Pipeline Co.*, Docket No. RP00-107-000, Exh. S-13, Prepared Direct and Answering Testimony of Commission Staff Witness George M. Shriver, III at 17 (June 7, 2000).

[111] Opinion No. 531 at P 8.

[112] *So. Cal. Edison Co.*, 92 FERC ¶ 61,070 at 61,261.

[113] Moreover, the Commission recently cited the potential that inadequate ROEs for electric transmission utilities could cause investors to deploy capital to other infrastructure projects with higher allowed ROEs, such as Commission-regulated natural gas pipelines. Opinion No 551 at P 128 n.292.

Q103. HOW DID YOU USE THE INFORMATION CONTAINED IN ROE DETERMINATIONS FOR NATURAL GAS PIPELINES TO DEVELOP AN ROE BENCHMARK FOR ELECTRIC UTILITIES?

A103. I first applied the risk premium approach discussed above to develop a current implied ROE for gas pipelines based on the Commission's historical allowed returns. My analysis then examined the historical ROE differential between the natural gas pipeline and electric utility industries, and then applied it to the current allowed ROE for natural gas pipelines to infer a corresponding ROE for electric utilities. As a result, this approach relies directly on the Commission's own determination as to the impact of relative industry risks and current returns.

Allowed ROEs approved by the Commission for natural gas pipelines for the years 2006 through 2016 are presented on pages 4 and 5 of Exhibit No. RECO-15. The average annual ROE, the corresponding average bond yields, and implied risk premiums are summarized on page 3 of Exhibit No. RECO-15. Consistent with state and Commission-approved ROEs for electric utilities, the implied equity risk premiums for gas pipelines increase as interest rates decline, and vice versa.

Q104. WHAT CURRENT COST OF EQUITY IS IMPLIED FOR AN ELECTRIC UTILITY BASED ON THESE ALLOWED GAS PIPELINE ROES?

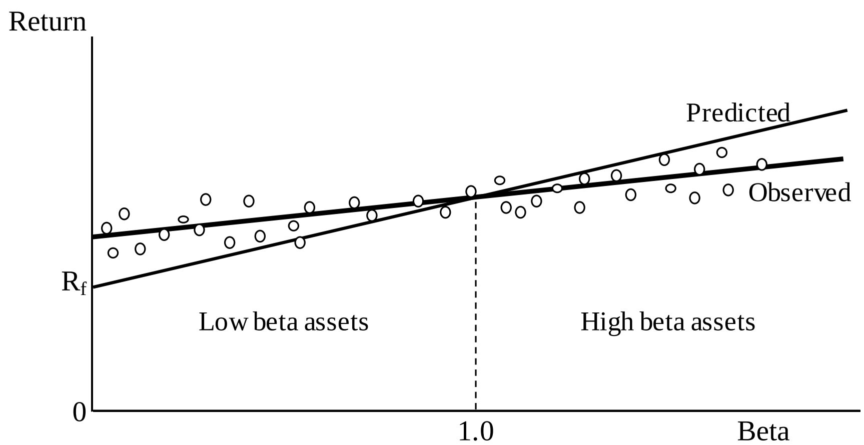
A104. As shown on page 1 of Exhibit No. RECO-15, adding an equity risk premium corresponding to current interest rate levels to the average yield on Baa utility bonds for the six-months ending December 2016 of 4.40% implies a current cost of equity for natural gas pipelines of 12.63%. As shown in the lower portion of page 3 of Exhibit No. RECO-15, the average ROE for natural gas pipelines has exceeded the ROE approved by the Commission for electric utilities by 2.27% between 2006 and 2016. Subtracting this spread from the 12.63% current risk premium estimate for natural gas pipelines results in a current implied ROE for an electric utility of 10.36%, if one were to assume that the risk spread between utilities and pipelines should remain constant.

C. Empirical CAPM

Q105. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A1. 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 risk returns than predicted by the CAPM. This is illustrated graphically in the figure below:

FIGURE RECO-2
CAPM – PREDICTED VS. OBSERVED RETURNS



Because the betas of utility stocks, including those in the Electric Group, are generally less than 1.0, this implies that cost of equity estimates based on the traditional CAPM would understate the cost of equity. 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.[114]

As discussed in New Regulatory Finance, based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$Rj = Rf + 0.25(Rm - Rf) + 0.75[\beta j(Rm - Rf)]$$

This ECAPM 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.

Q106. WHAT COST OF EQUITY ESTIMATES WERE INDICATED BY THE ECAPM?

A105. My application of the ECAPM approach was based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connection with the traditional CAPM. As shown on page 1 of Exhibit No. RECO-16, applying the forward-looking ECAPM approach to the firms in the Electric Group results in a cost of equity range of 8.40% to 11.60% after adjusting for firm size, with a median of 9.66%.[115]

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[114] Morin, New Regulatory Finance, *Supra* note 68, at 189.

[115] The midpoint of the ECAPM results based on historical bond yields was 10.00% after adjusting for firm size.

D. Projected Bond Yields

Q107. IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE RISK PREMIUM AND CAPM APPROACHES?

A106. Yes. As discussed earlier, there is widespread consensus that interest rates are currently anomalous, and will increase materially as the economy continues to strengthen and the Federal Reserve normalizes its monetary policies. As a result, current bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective (and beyond). Accordingly, in addition to the use of historical average bond yields, I also applied the risk premium, CAPM, and ECAPM methods based on projections for bond yields over the 2017-2021 horizon.

Q108. WHAT RISK PREMIUM COST OF EQUITY ESTIMATES ARE PRODUCED AFTER INCORPORATING FORECASTED BOND YIELDS?

A107. As shown on page 2 of Exhibit No. RECO-10, incorporating a forecasted yield for 2017-2021 and adjusting for changes in interest rates since the study period implied an equity risk premium based on Commission-authorized ROEs of 4.77% for electric utilities. Adding this equity risk premium to the implied average yield on Baa public utility bonds for 2017-2021 of 5.82% resulted in an implied cost of equity of 10.59%. Meanwhile, my risk premium analysis based on the Commission's findings for natural gas pipelines implied a cost of equity estimate of 10.57% based on the forecasted yield for utility bonds (Exhibit No. RECO-15, page 2).

Q109. DID YOU ALSO APPLY THE CAPM AND ECAPM USING FORECASTED BOND YIELDS?

A108. Yes. As shown on page 2 of Exhibit No. RECO-11, applying the CAPM using a forecasted Treasury bond yield for 2017-2021 implied an ROE range of 7.96% to 11.49% for the Electric Group, with a median of 9.28% and a midpoint of 9.73%. For the ECAPM (page 2 of Exhibit No. RECO-16), reference to forecasted Treasury bond yields resulted in an implied cost of equity range of 8.73% to 11.68%, with a median of 9.95% and a midpoint of 10.21%.

E. Low-Risk Non-Utility DCF Model

Q110. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR RECO?

A109. Consistent with underlying economic and regulatory standards, I also applied 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."

Q111. WHY DID YOU INCLUDE A DCF ANALYSIS FOR THIS NON-UTILITY GROUP?

A110. The primary reason I have examined DCF results for this Non-Utility Group is that utilities, such as RECO, 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.[116] 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.

Q112. WHAT AUTHORITY CAN YOU POINT TO FOR CONSIDERING THE RETURNS OF UNREGULATED ENTITIES?

A111. 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 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, which 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[.]"[117] It does not restrict consideration to other utilities. Indeed, if the requirement is business in the same part of the country and the utility has the exclusive franchise, then the Court could only be referring to non-utility businesses and any nearby 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."[118] As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

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[116] 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.

[117] *Bluefield*, 262 U.S. at 692.

[118] *Hope*, 320 U.S. at 603.

Q113. ARE DCF RESULTS FOR THE NON-UTILITY GROUP A USEFUL ADJUNCT WHEN APPLYING THE DCF MODEL?

A112. 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.

Q114. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A113. My comparable risk proxy group was 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 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.

Q115. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE PROXY GROUP?

A114. Table RECO-5 compares the Non-Utility Group with the Electric Group across five indicators of investment risk:

TABLE RECO-5
COMPARISON OF RISK INDICATORS

	Credit Ratings		Value Line		
			Safety	Financial	
Proxy Group	**S&P**	**Moody's**	**Rank**	**Strength**	**Beta**
Non-Utility	A-	A3	1	A+	0.72
Electric Group	A-	Baa1	2	A	0.69

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.[119] 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.

As the table shows, the average risk indicators for the Non-Utility Group suggest less risk than for the proxy group of electric utilities. A comparison of

[119] The Commission has previously considered Value Line's Safety Rank in evaluating relative risks. *Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152 at P 63 n.90 (citing cases).

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 Electric Group are greater than those of the firms in the Non-Utility Group.

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, General Mills, McDonalds, and Wal-Mart, 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 approaching 3%.

Q116. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A115. As shown on Exhibit No. RECO-17, I calculated the dividend yield component of the DCF model in exactly the same manner described earlier for the Electric Group. With respect to growth, my application of the DCF model to the Non-Utility Group relied on an average EPS growth rate based on projections from IBES and Zacks. As shown there, my DCF analysis for the Non-Utility Group resulted in an adjusted ROE range of 6.42% to 13.46%, with a median of 10.68% and a midpoint of 9.85%. As discussed above, considering expected returns for the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Considering that the investment risks of the Non-Utility Group are lower than those of the Electric Group, these results understate investors' required rate of return for RECO.

Q117. THE COMMISSION DECLINED TO CONSIDER THE IMPLICATIONS OF ROE RESULTS FOR GAS PIPELINES OR NON-UTILITY FIRMS IN OPINION NO. 531. WHY HAVE YOU INCLUDED THEM IN YOUR EVALUATION IN THIS PROCEEDING?

A116. The Commission stated that it would not consider the risk premium analysis based on allowed ROEs for gas pipelines or the non-utility DCF analysis "because those methodologies are not based on electric utilities."[120] With this said, given the Commission's observations regarding the evolution of the electric utility industry and its willingness to adopt the same two-step DCF approach used to establish ROEs for natural gas pipelines,[121] risk premiums for natural gas pipelines provide a very logical benchmark to evaluate corresponding DCF results for electric utilities. Moreover, my risk premium application does not assume that the gas pipeline and electric utility industries have equivalent risks or expected returns. Rather, I specifically consider and adjust for industry differences in arriving at an implied ROE using this method.

In addition, the fact that natural gas pipelines and non-utility firms do not operate in the same industry as electric utilities does not render them irrelevant. Investors have many opportunities for their capital and electric utilities must compete for funds with firms outside their own industry. The investment community has recognized the interrelationship between ROEs for pipelines and electric transmission companies in the allocation of capital. As Wolfe Research noted:

> Investors are concerned that a cut [in base ROEs for electric transmission] would cause an imbalance in the risk/reward trade-

[120] Opinion No. 531 at P 146 n.288.
[121] *Id.* at P 32.

> off of investing in transmission. In turn, the electric utility industry fears that investors could divert capital to other infrastructure investments with a more favorable risk/reward balance, such as natural gas pipelines, which are also regulated by FERC.[122]

For these same reasons, if electric transmission investments are unable to offer a return that is commensurate with what investors expect to earn from a non-regulated company of comparable risk, then capital will flow away from electric transmission to other competing investment opportunities. As the Commission noted in Opinion No. 531, utilities "must compete for capital with other utilities (<u>and companies in other sectors</u>) throughout the nation."[123]

Q118. PLEASE SUMMARIZE THE RESULTS OF YOUR ALTERNATIVE ROE BENCHMARKS.

A117. The cost of common equity estimates produced by the various tests of reasonableness discussed above are shown on page 2 of Exhibit No. RECO-7. The results of these alternative benchmarks confirm my conclusion that a base ROE of 10.2% is warranted for RECO.[124]

Q119. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A118. Yes.

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[122] Wolfe Research, "FERConomics: Risk to Transmission Base ROE in Focus," *supra* at note 25, at 2.

[123] Opinion No. 531 at P 96 (emphasis supplied).

[124] While I did not make an explicit adjustment to the results of my quantitative methods to include an adjustment for flotation costs, this is another legitimate consideration that supports the reasonableness of my evaluation of a just and reasonable base ROE for RECO in this case.

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A. This exhibit describes my background and experience and contains the details of my qualifications.

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 concerning the rate of return on equity ("ROE") in proceedings filed with the Federal Energy Regulatory Commission ("FERC"), the Regulatory Commission of Alaska, the Colorado Public Utilities Commission, the Hawaii Public Utilities Commission, the Idaho Public Utilities Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kansas State Corporation Commission, the Kentucky Public Service Commission, the Maryland Public Service Commission, the Montana Public Service Commission, the Nebraska Public Service Commission, the Ohio Public Utilities Commission, the Oregon Public Utilities Commission, the South Dakota Public Utilities Commission, the Virginia State Corporation Commission, the Washington Utilities and

Transportation Commission, the West Virginia Public Service Commission, and the Wyoming Public Service Commission. 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 ROE 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.

In addition, over the course of my career I have worked with Dr. William Avera to prepare prefiled direct and rebuttal testimony in over 250 regulatory proceedings before FERC, the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states.[1] Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. A resume containing the details of my qualifications and experience is attached below.

[1] This testimony was sponsored by Dr. William Avera, who is President of FINCAP, Inc.

ADRIEN M. McKENZIE

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458–4644
FAX (512) 458–4768
fincap3@texas.net

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 25 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

Principal 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 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 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 **Exhibit No. RECO-7**

OPINION NO. 531 BENCHMARKS

Two-Step DCF Model	Range	Central Tendency	Middle Top Half
IBES			
Median	6.28% -- 11.19%	8.52%	9.85%
Midpoint		8.74%	9.96%
Zacks			
Median	7.05% -- 11.19%	8.65%	9.92%
Midpoint		9.12%	10.15%

Opinion No. 531 Benchmark Methods	Range	Median	Midpoint
Risk Premium - FERC ROE	(a)	10.14%	10.14%
CAPM - Historical Bond Yield	7.52% -- 11.38%	8.89%	9.45%
Expected Earnings			
Industry (b)	(a)	10.54%	10.54%
Electric Group	8.59% -- 15.71%	11.19%	12.15%
State Authorized ROE			
RRA	9.30% -- 10.30%	9.74%	9.80%
Electric Group	9.10% -- 10.90%	10.28%	10.00%

(a) Point estimate value.

(b) Average for Value Line Electric Utility industry group.

SUMMARY OF RESULTS

CHECKS OF REASONABLENESS

Value Line-Based DCF	Range	Central Tendency	Middle Top Half
Median	6.52% -- 12.81%	8.48%	10.64%
Midpoint		9.66%	11.24%

	Range	Median	Midpoint
Risk Premium - Gas Pipelines	(a)	10.36%	10.36%
ECAPM - Historical Bond Yield	8.40% -- 11.60%	9.66%	10.00%
Projected Bond Yields			
Risk Premium			
FERC ROE	(a)	10.59%	10.59%
FERC Gas Pipelines	(a)	10.57%	10.57%
CAPM	7.96% -- 11.49%	9.28%	9.73%
ECAPM	8.73% -- 11.68%	9.95%	10.21%
Non-Utility DCF	#REF! -- #REF!	10.68%	9.85%

(a) Point estimate value.

RISK MEASURES **Exhibit No. RECO-8**

ELECTRIC GROUP

			(a)	(b)	(c)			(d)
			S&P Corporate Rating	**Moody's Long-term Rating**	**Value Line**			**Market Cap**
	Company	**SYM**			**Safety Rank**	**Financial Strength**	**Beta**	
1	ALLETE	ALE	BBB+	A3	2	A	0.75	$3,192
2	Alliant Energy	LNT	A-	Baa1	2	A	0.70	$8,420
3	Ameren Corp.	AEE	BBB+	Baa1	2	A	0.65	$12,397
4	American Elec Pwr	AEP	BBB+	Baa1	2	A	0.65	$30,540
5	Avangrid, Inc.	AGR	BBB+	Baa1	3	B+	NA	$11,393
6	CenterPoint Energy	CNP	A-	Baa1	3	B+	0.85	$10,470
7	Consolidated Edison	ED	A-	A3	1	A+	0.55	$20,234
8	DTE Energy Co.	DTE	BBB+	Baa1	2	B++	0.65	$17,350
9	Duke Energy Corp.	DUK	A-	Baa1	2	A	0.60	$52,385
10	Edison International	EIX	BBB+	A3	2	A	0.65	$22,869
11	Eversource Energy	ES	A	Baa1	1	A	0.70	$17,010
12	OGE Energy Corp.	OGE	A-	A3	2	A	0.90	$6,708
13	PG&E Corp.	PCG	BBB+	Baa1	3	B+	0.65	$30,316
14	Pinnacle West Capital	PNW	A-	A3	1	A+	0.70	$8,436
15	Sempra Energy	SRE	BBB+	Baa1	2	A	0.80	$25,193
16	Vectren Corp.	VVC	A-	NR	2	A	0.75	$4,316
17	WEC Energy Group	WEC	A-	A3	1	A+	0.60	$18,034
18	Xcel Energy Inc.	XEL	A-	A3	1	A+	0.60	$20,430
			A-	**Baa1**	**2**	**A**	**0.69**	**$17,761**

(a) Issuer credit rating from www.standardandpoors.com (retrieved Dec. 20, 2016).
(b) Long-term rating from www.moodys.com (retrieved Dec. 20, 2016).
(c) The Value Line Investment Survey (Oct. 28, Nov. 18, & Dec. 16, 2016).
(d) www.valueline.com (retrieved Dec. 20, 2016).

DCF MODEL - ELECTRIC GROUP **Exhibit No. RECO-9**

IBES GROWTH

		(a)	(b)	(c)	(d)	(e)	(f)	(g)		
		Dividend Yield			Growth Rate					
	Company	6-Mo. Average	Adjustment	Adjusted	IBES	GDP	Weighted	Cost of Equity		
1	ALLETE	3.38%	1.0250	3.47%	5.00%	4.31%	4.77%	8.24%		
2	Alliant Energy	3.09%	1.0300	3.18%	6.00%	4.31%	5.44%	8.62%		
3	Ameren Corp.	3.41%	1.0283	3.50%	5.65%	4.31%	5.20%	8.71%		
4	American Elec Pwr	3.54%	1.0095	3.58%	1.90%	4.31%	2.70%	6.28%		
5	Avangrid, Inc.	4.25%	1.0400	4.42%	8.00%	4.31%	6.77%	11.19%		
6	CenterPoint Energy	4.41%	1.0332	4.56%	6.63%	4.31%	5.86%	10.42%		
7	Consolidated Edison	3.57%	1.0107	3.61%	2.13%	4.31%	2.86%	6.46%		
8	DTE Energy Co.	3.22%	1.0282	3.31%	5.63%	4.31%	5.19%	8.50%		
9	Duke Energy Corp.	4.25%	1.0085	4.29%	1.70%	4.31%	2.57%	6.86%		
10	Edison International	2.70%	1.0104	2.73%	2.07%	4.31%	2.82%	5.54%		
11	Eversource Energy	3.24%	1.0291	3.33%	5.82%	4.31%	5.32%	8.65%		
12	OGE Energy Corp.	3.66%	1.0200	3.74%	4.00%	4.31%	4.10%	7.84%		
13	PG&E Corp.	3.18%	1.0286	3.27%	5.71%	4.31%	5.24%	8.52%		
14	Pinnacle West Capital	3.35%	1.0237	3.43%	4.73%	4.31%	4.59%	8.02%		
15	Sempra Energy	2.86%	1.0325	2.96%	6.50%	4.31%	5.77%	8.73%		
16	Vectren Corp.	3.24%	1.0229	3.32%	4.57%	4.31%	4.48%	7.80%		
17	WEC Energy Group	3.31%	1.0346	3.42%	6.92%	4.31%	6.05%	9.47%		
18	Xcel Energy Inc.	3.28%	1.0283	3.38%	5.65%	4.31%	5.20%	8.58%		
	Range of Reasonableness							**5.54%**	**--**	**11.19%**
	Adjusted Range of Reasonableness (h)							**6.28%**	**--**	**11.19%**
	Median							**8.52%**		
	Midpoint - Top Half							**9.85%**		
	Midpoint							**8.74%**		
	Midpoint - Top Half							**9.96%**		

(a) Six-month average dividend yield for Jul. - Dec. 2016.
(b) 1 + 0.5 x (d).
(c) (a) x (b).
(d) www.finance.yahoo.com (Jan. 9, 2017).
(e) See Exhibit No. REC-104, page 3.
(f) (d) x 2/3 + (e) x 1/3.
(g) (c) + (f).
(h) Excludes highlighted values.

DCF MODEL - ELECTRIC GROUP **Exhibit No. RECO-9**

ZACKS GROWTH

		(a)	(b)	(c)	(d)	(e)	(f)	(g)		
		Dividend Yield			Growth Rate					
	Company	6-Mo. Average	Adjustment	Adjusted	Zacks	GDP	Weighted		Cost of Equity	
1	ALLETE	3.38%	1.0275	3.47%	5.50%	4.31%	5.10%		8.58%	
2	Alliant Energy	3.09%	1.0275	3.17%	5.50%	4.31%	5.10%		8.27%	
3	Ameren Corp.	3.41%	1.0325	3.52%	6.50%	4.31%	5.77%		9.29%	
4	American Elec Pwr	3.54%	1.0269	3.64%	5.38%	4.31%	5.02%		8.66%	
5	Avangrid, Inc.	4.25%	1.0400	4.42%	8.00%	4.31%	6.77%		11.19%	
6	CenterPoint Energy	4.41%	1.0250	4.53%	5.00%	4.31%	4.77%		9.30%	
7	Consolidated Edison	3.57%	1.0154	3.62%	3.07%	4.31%	3.48%		7.11%	
8	DTE Energy Co.	3.22%	1.0292	3.32%	5.83%	4.31%	5.32%		8.64%	
9	Duke Energy Corp.	4.25%	1.0251	4.36%	5.02%	4.31%	4.78%		9.14%	
10	Edison International	2.70%	1.0307	2.78%	6.13%	4.31%	5.52%		8.30%	
11	Eversource Energy	3.24%	1.0317	3.34%	6.33%	4.31%	5.66%		9.00%	
12	OGE Energy Corp.	3.66%	1.0267	3.76%	5.33%	4.31%	4.99%		8.75%	
13	PG&E Corp.	3.18%	1.0178	3.24%	3.56%	4.31%	3.81%		7.05%	
14	Pinnacle West Capital	3.35%	1.0246	3.44%	4.92%	4.31%	4.72%		8.15%	
15	Sempra Energy	2.86%	1.0372	2.97%	7.43%	4.31%	6.39%		9.36%	
16	Vectren Corp.	3.24%	1.0267	3.33%	5.33%	4.31%	4.99%		8.32%	
17	WEC Energy Group	3.31%	1.0300	3.40%	6.00%	4.31%	5.44%		8.84%	
18	Xcel Energy Inc.	3.28%	1.0272	3.37%	5.43%	4.31%	5.06%		8.43%	
	Range of Reasonableness							**7.05%**	**--**	**11.19%**
	Median								**8.65%**	
	Midpoint - Top Half								**9.92%**	
	Midpoint								**9.12%**	
	Midpoint - Top Half								**10.15%**	

(a) Six-month average dividend yield for Jul. - Dec. 2016.
(b) 1 + 0.5 x (d).
(c) (a) x (b).
(d) www.zacks.com (Jan. 9, 2017).
(e) See Exhibit No. REC-104, page 3.
(f) (d) x 2/3 + (e) x 1/3.
(g) (c) + (f).

GDP GROWTH RATE

	Source	Nominal GDP ($ Billions) 2021	2040	2046	2071	Compound Annual Growth Rate
(a)	**IHS Global Insight**	23,120.9		64,776.8		4.21%
(b)	**Energy Information Administration**					
	Real GDP	18,928	28,397			
	GDP Deflator	1.242	1.848			
		23,510	52,478			4.32%
(c)	**SSA Trustees Report**	24,081			207,026	4.40%
	Average GDP Growth Rate					**4.31%**

(a) IHS Global Insight (Aug. 24, 2016).
(b) Energy Information Administration, *Annual Energy Outlook 2016 Early Release* (May 17, 2016).
(c) Social Security Administration, *2016 OASDI Trustees Report*, Table VI.G6.-Selected Economic Variables.

RISK PREMIUM - FERC ROE

HISTORICAL BOND YIELDS

Current Equity Risk Premium

(a)	Average Yield Over Study Period	5.71%
(b)	Baa Utility Bond Yield - Historical	4.40%
	Change in Bond Yield	-1.31%
(c)	Risk Premium/Interest Rate Relationship	-0.6834
	Adjustment to Average Risk Premium	0.90%
(a)	Average Risk Premium over Study Period	4.84%
	Adjusted Risk Premium	**5.74%**

Implied Cost of Equity

(b)	Baa Utility Bond Yield - Historical	4.40%
	Adjusted Equity Risk Premium	5.74%
	Risk Premium Cost of Equity	**10.14%**

(a) See Exhibit No. REC-105, p. 3.
(b) Six-month average yield for Jul. - Dec. 2016 based on data from Moody's Investors Service, www.moodys.credittrends.com.
(c) See Exhibit No. REC-105, p. 7.

PROJECTED BOND YIELDS

Current Equity Risk Premium

(a)	Average Yield Over Study Period	5.71%
(b)	Baa Utility Bond Yield 2017-21	5.82%
	Change in Bond Yield	0.11%
(c)	Risk Premium/Interest Rate Relationship	-0.6834
	Adjustment to Average Risk Premium	-0.07%
(a)	Average Risk Premium over Study Period	4.84%
	Adjusted Risk Premium	**4.77%**

Implied Cost of Equity

(b)	A/Baa Utility Bond Yield 2017-21	5.82%
	Adjusted Equity Risk Premium	4.77%
	Risk Premium Cost of Equity	**10.59%**

(a) See Exhibit No. REC-105, p. 3.

(b) Based on data from IHS Global Insight (Jan. 3, 2017); Energy Information Administration, Annual Energy Outlook 2016 (Sep. 15, 2016); & Moody's Investors Service at www.credittrends.com.

(c) See Exhibit No. REC-105, p. 7.

RISK PREMIUM - FERC ROE **Exhibit No. RECO-10**

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	10.17%	4.98%	5.18%
2014	10.15%	4.80%	5.35%
2015	10.09%	5.03%	5.06%
2016	9.92%	4.68%	5.24%
		5.71%	4.84%

(a) Exhibit No. REC-105, pp. 4-6.
(b) Moody's Investors Service, www.credittrends.com.

RISK PREMIUM - FERC ROE **Exhibit No. RECO-10**

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%

RISK PREMIUM - FERC ROE

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%
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%
Jun-14	EL11-66	New England Transmission Owners	10.57%
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	ER15-2114	Transource West Virginia, LLC	10.00%
Mar-16	EL14-93	Westar Energy	9.80%
Apr-16	ER15-1809	ATX Southwest, LLC	9.90%
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	9.80%
Oct-16	ER15-2239	NextEra Energy Transmission West	9.70%
Oct-16	ER15-1682	TransCanyon	9.80%
Sep-16	EL14-12	Midwest ISO Transmission Owners	10.32%

(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.

RISK PREMIUM - FERC ROE

REGRESSION RESULTS

Regression Statistics	
Multiple R	0.92361
R Square	0.85306
Adjusted R Square	0.83673
Standard Error	0.00278
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.000404	0.00040	52.24987	4.9296E-05
Residual	9	0.000070	0.00001		
Total	10	0.000473			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0874	0.00546	15.99791	0.00000	7.5065E-02	0.09979	0.07506	0.09979
X Variable 1	-0.6834	0.09454	-7.22841	0.00005	-8.9726E-01	-0.46952	-0.89726	-0.46952

CAPM - HISTORICAL BOND YIELD **Exhibit No. RECO-11**

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	Implied Cost of Equity
1	ALLETE	2.5%	8.9%	11.4%	2.6%	8.8%	0.75	9.20%	$3,192	1.49%	10.69%
2	Alliant Energy	2.5%	8.9%	11.4%	2.6%	8.8%	0.70	8.76%	$8,420	0.86%	9.62%
3	Ameren Corp.	2.5%	8.9%	11.4%	2.6%	8.8%	0.65	8.32%	$12,397	0.57%	8.89%
4	American Elec Pwr	2.5%	8.9%	11.4%	2.6%	8.8%	0.65	8.32%	$30,540	-0.36%	7.96%
5	Avangrid, Inc.	2.5%	8.9%	11.4%	2.6%	8.8%	NA	NA	$11,393	0.57%	NA
6	CenterPoint Energy	2.5%	8.9%	11.4%	2.6%	8.8%	0.85	10.08%	$10,470	0.57%	10.65%
7	Consolidated Edison	2.5%	8.9%	11.4%	2.6%	8.8%	0.55	7.44%	$20,234	0.57%	8.01%
8	DTE Energy Co.	2.5%	8.9%	11.4%	2.6%	8.8%	0.65	8.32%	$17,350	0.57%	8.89%
9	Duke Energy Corp.	2.5%	8.9%	11.4%	2.6%	8.8%	0.60	7.88%	$52,385	-0.36%	7.52%
10	Edison International	2.5%	8.9%	11.4%	2.6%	8.8%	0.65	8.32%	$22,869	-0.36%	7.96%
11	Eversource Energy	2.5%	8.9%	11.4%	2.6%	8.8%	0.70	8.76%	$17,010	0.57%	9.33%
12	OGE Energy Corp.	2.5%	8.9%	11.4%	2.6%	8.8%	0.90	10.52%	$6,708	0.86%	11.38%
13	PG&E Corp.	2.5%	8.9%	11.4%	2.6%	8.8%	0.65	8.32%	$30,316	-0.36%	7.96%
14	Pinnacle West Capital	2.5%	8.9%	11.4%	2.6%	8.8%	0.70	8.76%	$8,436	0.86%	9.62%
15	Sempra Energy	2.5%	8.9%	11.4%	2.6%	8.8%	0.80	9.64%	$25,193	-0.36%	9.28%
16	Vectren Corp.	2.5%	8.9%	11.4%	2.6%	8.8%	0.75	9.20%	$4,316	0.99%	10.19%
17	WEC Energy Group	2.5%	8.9%	11.4%	2.6%	8.8%	0.60	7.88%	$18,034	0.57%	8.45%
18	Xcel Energy Inc.	2.5%	8.9%	11.4%	2.6%	8.8%	0.60	7.88%	$20,430	0.57%	8.45%
	Range of Reasonableness							**7.44% -- 10.52%**			**7.52% -- 11.38%**
	Midpoint							**8.98%**			**9.45%**
	Median							**8.32%**			**8.89%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Nov. 28, 2016).
(b) Average of weighted average earnings growth rates from IBES and Zacks for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Nov. 28, 2016) and www.zacks.com (retrieved Nov. 28, 2016).
(c) Six-month average yield on 30-year Treasury bonds for Jul. - Dec. 2016 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/htm.
(d) The Value Line Investment Survey (Oct. 28, Nov. 18, & Dec. 16, 2016).
(e) www.finance.yahoo.com (Jan. 9, 2017).
(f) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.

CAPM - PROJECTED BOND YIELD

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	Implied Cost of Equity
1	ALLETE	2.5%	8.9%	11.4%	3.7%	7.7%	0.75	9.48%	$3,192	1.49%	10.97%
2	Alliant Energy	2.5%	8.9%	11.4%	3.7%	7.7%	0.70	9.09%	$8,420	0.86%	9.95%
3	Ameren Corp.	2.5%	8.9%	11.4%	3.7%	7.7%	0.65	8.71%	$12,397	0.57%	9.28%
4	American Elec Pwr	2.5%	8.9%	11.4%	3.7%	7.7%	0.65	8.71%	$30,540	-0.36%	8.35%
5	Avangrid, Inc.	2.5%	8.9%	11.4%	3.7%	7.7%	NA	NA	$11,393	0.57%	NA
6	CenterPoint Energy	2.5%	8.9%	11.4%	3.7%	7.7%	0.85	10.25%	$10,470	0.57%	10.82%
7	Consolidated Edison	2.5%	8.9%	11.4%	3.7%	7.7%	0.55	7.94%	$20,234	0.57%	8.51%
8	DTE Energy Co.	2.5%	8.9%	11.4%	3.7%	7.7%	0.65	8.71%	$17,350	0.57%	9.28%
9	Duke Energy Corp.	2.5%	8.9%	11.4%	3.7%	7.7%	0.60	8.32%	$52,385	-0.36%	7.96%
10	Edison International	2.5%	8.9%	11.4%	3.7%	7.7%	0.65	8.71%	$22,869	-0.36%	8.35%
11	Eversource Energy	2.5%	8.9%	11.4%	3.7%	7.7%	0.70	9.09%	$17,010	0.57%	9.66%
12	OGE Energy Corp.	2.5%	8.9%	11.4%	3.7%	7.7%	0.90	10.63%	$6,708	0.86%	11.49%
13	PG&E Corp.	2.5%	8.9%	11.4%	3.7%	7.7%	0.65	8.71%	$30,316	-0.36%	8.35%
14	Pinnacle West Capital	2.5%	8.9%	11.4%	3.7%	7.7%	0.70	9.09%	$8,436	0.86%	9.95%
15	Sempra Energy	2.5%	8.9%	11.4%	3.7%	7.7%	0.80	9.86%	$25,193	-0.36%	9.50%
16	Vectren Corp.	2.5%	8.9%	11.4%	3.7%	7.7%	0.75	9.48%	$4,316	0.99%	10.47%
17	WEC Energy Group	2.5%	8.9%	11.4%	3.7%	7.7%	0.60	8.32%	$18,034	0.57%	8.89%
18	Xcel Energy Inc.	2.5%	8.9%	11.4%	3.7%	7.7%	0.60	8.32%	$20,430	0.57%	8.89%
	Range of Reasonableness							**7.94% -- 10.63%**			**7.96% -- 11.49%**
	Midpoint							**9.28%**			**9.73%**
	Median							**8.71%**			**9.28%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Nov. 28, 2016).
(b) Average of weighted average earnings growth rates from IBES and Zacks for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Nov. 28, 2016) and www.zacks.com (retrieved Nov. 28, 2016).
(c) Average yield on 30-year Treasury bonds for 2017-21 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Dec. 2, 2016); IHS Global Insight (Jan. 3, 2017); & Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 12 (Dec. 1, 2016).
(d) The Value Line Investment Survey (Oct. 28, Nov. 18, & Dec. 16, 2016).
(e) www.finance.yahoo.com (Jan. 9, 2017).
(f) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.

EXPECTED EARNINGS APPROACH **Exhibit No. RECO-12**

ELECTRIC GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity		
1	ALLETE	9.00%	1.0187	9.17%		
2	Alliant Energy	12.50%	1.0086	12.61%		
3	Ameren Corp.	9.50%	1.0173	9.66%		
4	American Elec Pwr	10.50%	1.0135	10.64%		
5	Avangrid, Inc.	5.50%	1.0050	5.53%		
6	CenterPoint Energy	15.50%	1.0135	15.71%		
7	Consolidated Edison	8.50%	1.0228	8.69%		
8	DTE Energy Co.	10.50%	1.0254	10.77%		
9	Duke Energy Corp.	8.50%	1.0109	8.59%		
10	Edison International	11.50%	1.0253	11.79%		
11	Eversource Energy	9.50%	1.0185	9.68%		
12	OGE Energy Corp.	11.50%	1.0180	11.71%		
13	PG&E Corp.	11.00%	1.0292	11.32%		
14	Pinnacle West Capital	10.00%	1.0197	10.20%		
15	Sempra Energy	14.00%	1.0117	14.16%		
16	Vectren Corp.	13.00%	1.0288	13.37%		
17	WEC Energy Group	11.00%	1.0172	11.19%		
18	Xcel Energy Inc.	11.00%	1.0209	11.23%		
	Range of Reasonableness			**5.53%**	**--**	**15.71%**
	Adjusted Range of Reasonableness (d)			**8.59%**	**--**	**15.71%**
	Midpoint				**12.15%**	
	Median (d)				**11.19%**	

(a) The Value Line Investment Survey (Oct. 28, Nov. 18, & Dec. 16, 2016).
(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.

STATE ALLOWED ROEs **Exhibit No. RECO-13**

RRA INTEGRATED ELECTRIC UTILITIES

(24-Months Ended September 30, 2016)

	Company	State	Date	Allowed ROE	Adder / Penalty	Base ROE
1	Nevada Power	NV	10/09/14	9.80%	0.00%	9.80%
2	MidAmerican Energy	IL	11/06/14	9.56%	0.00%	9.56%
3	Wisconsin Public Service Co.	WI	11/06/14	10.20%	0.00%	10.20%
4	Wisconsin Electric Power	WI	11/14/14	10.20%	0.00%	10.20%
5	Appalachian Power	VA	11/26/14	9.70%	0.00%	9.70%
6	Madison Gas & Electric Co.	WI	11/26/14	10.20%	0.00%	10.20%
7	Portland General Electric	OR	12/04/14	9.68%	0.00%	9.68%
8	Entergy Mississippi	MS	12/11/14	10.07%	0.00%	10.07%
9	Northern States Power WI	WI	12/12/14	10.20%	0.00%	10.20%
10	Black Hills Colorado Electric	CO	12/18/14	9.83%	0.00%	9.83%
11	PacifiCorp	WY	01/23/15	9.50%	0.00%	9.50%
12	Public Service Co. of CO	CO	02/24/15	9.83%	0.00%	9.83%
13	PacifiCorp	WA	03/25/15	9.50%	0.00%	9.50%
14	Northern State Power MN	MN	03/26/15	9.72%	0.00%	9.72%
15	Wisconsin Public Service	MI	04/23/15	10.20%	0.00%	10.20%
16	Union Electric	MO	04/29/15	9.53%	0.00%	9.53%
17	Appalachian Power	WV	05/26/15	9.75%	0.00%	9.75%
18	Kansas City Power and Light	MO	09/02/15	9.50%	0.00%	9.50%
19	Kansas City Power and Light	KS	09/23/15	9.30%	0.00%	9.30%
20	Wisconsin Public Service Corp.	WI	11/19/15	10.00%	0.00%	10.00%
21	Consumers Energy Co.	MI	11/19/15	10.30%	0.00%	10.30%
22	Mississippi Power	MS	12/03/15	9.23%	(a)	(a)
23	Northern States Power Co - WI	WI	12/03/15	10.00%	0.00%	10.00%
24	DTE Electric Co.	MI	12/11/15	10.30%	0.00%	10.30%
25	Portland General Electric Co.	OR	12/15/15	9.60%	0.00%	9.60%
26	Southwestern Public Service Co	TX	12/17/15	9.70%	0.00%	9.70%
27	Avista Corp.	ID	12/18/15	9.50%	0.00%	9.50%
28	PacifiCorp	WY	12/30/15	9.50%	0.00%	9.50%
29	Virginia Electric and Power	VA	(b)	(b)	(b)	10.00%
30	Avista Corp	WA	01/06/16	9.50%	0.00%	9.50%
31	Entergy Arkansas	AR	02/23/16	9.75%	0.00%	9.75%
32	Virginia Electric and Power	VA	(c)	(c)	(c)	9.60%
33	Indianapolis Power & Light Co.	IN	03/16/16	9.85%	-0.15%	10.00%
34	El Paso Electric Co.	NM	06/08/16	9.48%	0.00%	9.48%
35	Virginia Electric and Power	VA	(d)	(d)	(d)	9.60%
36	Northern Indiana Public Service Co.	IN	7/18/2016	9.98%	0.00%	9.98%
37	Kingsport Power Co.	TN	08/09/16	9.85%	0.00%	9.85%
38	UNS Electric	AZ	08/18/16	9.50%	0.00%	9.50%
39	PacifiCorp	WA	09/01/16	9.50%	0.00%	9.50%
40	Upper Peninsula Power	MI	09/08/16	10.00%	0.00%	10.00%
41	Public Service Co. of New Mexico	NM	09/28/16	9.58%	0.00%	9.58%

Range of Reasonableness **9.30% -- 10.30%**

Midpoint **9.80%**

Median	**9.74%**
Percent >= 9.60%	**67.5%**

RRA INTEGRATED ELECTRIC UTILITIES

Notes

(a) Base ROE is unknown. Order is for limited period and intent.

(b) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	2/18/2015	11.00%	1.00%	10.00%
Virginia Electric and Power	VA	3/12/2015	12.00%	2.00%	10.00%
Virginia Electric and Power	VA	3/12/2015	11.00%	1.00%	10.00%
Virginia Electric and Power	VA	3/12/2015	11.00%	1.00%	10.00%
Virginia Electric and Power	VA	4/21/2015	11.00%	1.00%	10.00%

(c) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	2/29/2016	11.60%	2.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	2/29/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	3/29/2016	9.60%	0.00%	9.60%

(c) Adjusted to condense the following duplicative project-specific ROE orders:

	State	Date	Allowed ROE	Adder / Penalty	Base ROE
Virginia Electric and Power	VA	6/30/2016	10.60%	1.00%	9.60%
Virginia Electric and Power	VA	6/30/2016	9.60%	0.00%	9.60%

Source: Regulatory Research Associates, "Major Rate Case Decisions," *Regulatory Focus* (Jan. 15, 2015, Jan. 14, 2016, & Oct. 14, 2016).

STATE ALLOWED ROEs **Exhibit No. RECO-13**

ELECTRIC GROUP

	Company	(a) Allowed ROE		
1	ALLETE		10.38%	
2	Alliant Energy		10.90%	
3	Ameren Corp.		9.12%	
4	American Elec Pwr		10.28%	
5	Avangrid, Inc.		NA	
6	CenterPoint Energy		10.00%	
7	Consolidated Edison		9.10%	
8	DTE Energy Co.		10.30%	
9	Duke Energy Corp.		10.38%	
10	Edison International		10.45%	
11	Eversource Energy		9.43%	
12	OGE Energy Corp.		10.08%	
13	PG&E Corp.		10.40%	
14	Pinnacle West Capital		10.00%	
15	Sempra Energy		10.30%	
16	Vectren Corp.		10.28%	
17	WEC Energy Group		9.55%	
18	Xcel Energy Inc.		9.80%	
	Range of Reasonableness	**9.10%**	--	**10.90%**
	Midpoint		**10.00%**	
	Median		**10.28%**	

(a) The Value Line Investment Survey (Oct. 28, Nov. 18, & Dec. 16, 2016).

DCF MODEL - ELECTRIC GROUP **Exhibit No. RECO-14**

VALUE LINE GROWTH

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	
		Dividend Yield			Growth Rate				
	Company	6-Mo. Average	Adjustment	Adjusted	V Line	GDP	Weighted	Cost of Equity	
1	ALLETE	3.38%	1.0200	3.45%	4.00%	4.31%	4.10%	7.55%	
2	Alliant Energy	3.09%	1.0300	3.18%	6.00%	4.31%	5.44%	8.62%	
3	Ameren Corp.	3.41%	1.0300	3.51%	6.00%	4.31%	5.44%	8.94%	
4	American Elec Pwr	3.54%	1.0250	3.63%	5.00%	4.31%	4.77%	8.40%	
5	Avangrid, Inc.	4.25%	NA	NA	NA	4.31%	NA	NA	
6	CenterPoint Energy	4.41%	1.0100	4.46%	2.00%	4.31%	2.77%	7.23%	
7	Consolidated Edison	3.57%	1.0125	3.61%	2.50%	4.31%	3.10%	6.72%	
8	DTE Energy Co.	3.22%	1.0300	3.32%	6.00%	4.31%	5.44%	8.75%	
9	Duke Energy Corp.	4.25%	1.0200	4.34%	4.00%	4.31%	4.10%	8.44%	
10	Edison International	2.70%	1.0175	2.75%	3.50%	4.31%	3.77%	6.52%	
11	Eversource Energy	3.24%	1.0300	3.34%	6.00%	4.31%	5.44%	8.77%	
12	OGE Energy Corp.	3.66%	1.0150	3.72%	3.00%	4.31%	3.44%	7.15%	
13	PG&E Corp.	3.18%	1.0600	3.37%	12.00%	4.31%	9.44%	12.81%	
14	Pinnacle West Capital	3.35%	1.0200	3.42%	4.00%	4.31%	4.10%	7.52%	
15	Sempra Energy	2.86%	1.0400	2.98%	8.00%	4.31%	6.77%	9.75%	
16	Vectren Corp.	3.24%	1.0450	3.39%	9.00%	4.31%	7.44%	10.83%	
17	WEC Energy Group	3.31%	1.0300	3.40%	6.00%	4.31%	5.44%	8.84%	
18	Xcel Energy Inc.	3.28%	1.0275	3.38%	5.50%	4.31%	5.10%	8.48%	
	Range of Reasonableness							**6.52% --**	**12.81%**
	Median							**8.48%**	
	Midpoint - Top Half							**10.64%**	
	Midpoint							**9.66%**	
	Midpoint - Top Half							**11.24%**	

(a) Six-month average dividend yield for Jul. - Dec. 2016.
(b) 1 + 0.5 x (d).
(c) (a) x (b).
(d) The Value Line Investment Survey (Oct. 28, Nov. 18, & Dec. 16, 2016).
(e) See Exhibit No. REC-104, page 2.
(f) (d) x 2/3 + (e) x 1/3.
(g) (c) + (f).
(h) Excludes highlighted values.

RISK PREMIUM - GAS PIPELINE ROE **Exhibit No. RECO-15**

HISTORICAL BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield Over Study Period	5.71%
(b)	Average Baa Utility Bond Yield - Historical	4.40%
	Change in Bond Yield	-1.31%
(c)	Risk Premium/Interest Rate Relationship	-0.8520
	Adjustment to Average Risk Premium	1.12%
(a)	Average Risk Premium over Study Period	7.11%
	Adjusted Risk Premium	**8.23%**

Implied Cost of Equity - Gas Pipelines

(b)	Average Baa Utility Bond Yield - Historical	4.40%
	Adjusted Equity Risk Premium	8.23%
	Risk Premium Cost of Equity - Gas Pipeline	**12.63%**
	Less: Average Spread / Gas Pipeline - Electric Utility ROE	**2.27%**
	Implied Electric ROE	**10.36%**

(a) See Exhibit No. REC-110, p. 3.
(b) Six-month average yield on all utility bonds and Baa subset for Jul. - Dec. 2016 based on data from Moody's Investors Service, www.moodys.credittrends.com.
(c) See Exhibit No. REC-110, p. 6.

PROJECTED BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield Over Study Period	5.71%
(b)	Baa Utility Bond Yield 2017-21	5.82%
	Change in Bond Yield	0.11%
(c)	Risk Premium/Interest Rate Relationship	-0.8520
	Adjustment to Average Risk Premium	-0.09%
(a)	Average Risk Premium over Study Period	7.11%
	Adjusted Risk Premium	**7.02%**

Implied Cost of Equity

(b)	Baa Utility Bond Yield 2017-21	5.82%
	Adjusted Equity Risk Premium	7.02%
	Risk Premium Cost of Equity - Gas Pipeline	**12.84%**
	Less: Average Spread / Gas Pipeline - Electric Utility ROE	**2.27%**
	Implied Electric ROE	**10.57%**

(a) See Exhibit No. REC-110, p. 3.
(b) Based on data from IHS Global Insight (Jan. 3, 2017); Energy Information Administration, Annual Energy Outlook 2016 (Sep. 15, 2016); & Moody's Investors Service at www.credittrends.com.

(c) See Exhibit No. REC-110, p. 6.

RISK PREMIUM - GAS PIPELINE ROE **Exhibit No. RECO-15**

IMPLIED RISK PREMIUM

Year	(a) Average Pipeline ROE	(b) Baa Utility Bond Yield	Risk Premium
2006	12.86%	6.32%	6.54%
2007	13.04%	6.33%	6.71%
2008	12.86%	7.25%	5.61%
2009	13.18%	7.06%	6.12%
2010	12.61%	5.98%	6.63%
2011	13.31%	5.57%	7.74%
2012	12.65%	4.86%	7.79%
2013	11.48%	4.98%	6.50%
2014	13.69%	4.80%	8.89%
2015	13.10%	5.03%	8.07%
2016	12.28%	4.68%	7.60%
		5.71%	7.11%

Year	Average Pipeline ROE	(c) Average Electric Base ROE	Spread
2006	12.86%	11.01%	1.85%
2007	13.04%	10.96%	2.08%
2008	12.86%	10.83%	2.03%
2009	13.18%	10.85%	2.33%
2010	12.61%	10.59%	2.02%
2011	13.31%	10.68%	2.63%
2012	12.65%	10.82%	1.83%
2013	11.48%	10.17%	1.32%
2014	13.69%	10.15%	3.54%
2015	13.10%	10.09%	3.01%
2016	12.28%	9.92%	2.36%
			2.27%

(a) Exhibit No. REC-110, pp. 4-5.

(b) Moody's Investors Service, www.credittrends.com.

(c) Exhibit No. REC-105, p. 3.

RISK PREMIUM - GAS PIPELINE ROE **Exhibit No. RECO-15**

ALLOWED ROE

Date	Docket No.	Company	Allowed ROE
Feb-06	RP06-63	Guardian Pipeline LLC.	14.00%
Mar-06	CP05-372	Midwestern Gas Transmission Co.	13.00%
Mar-06	RP04-274	Kern River Gas Transmission Co.	9.34%
May-06	CP02-378	Cameron Interstate Pipeline, LLC	14.00%
Jun-06	CP04-411	Crown Landing LLC; Texas Eastern Transmission, LP	12.75%
Jun-06	CP05-83	Port Arthur Pipeline, L.P.	14.00%
Jun-06	CP05-130	Dominion Cove Point LNG	13.00%
Jun-06	CP05-360	Creole Trail LNG, L.P.	14.00%
Jul-06	CP06-71	Carolina Gas Transmission Corp.; SCG Pipeline, Inc.	12.70%
Jul-06	CP06-5	Empire State Pipeline	12.50%
Sep-06	CP06-354	Rockies Express Pipeline LLC	13.00%
Sep-06	CP06-167	Questar Overthrust Pipeline Co.	11.75%
Oct-06	RP04-274	Kern River Gas Transmission Co.	11.20%
Oct-06	CP06-61	North Baja Pipeline, LLC	14.00%
Dec-06	CP06-5	Empire Pipeline, Inc.	12.50%
Dec-06	CP98-150	Millennium Pipeline Co.	14.00%
Feb-07	CP06-403	Northern Natural Gas Co.	13.42%
Mar-07	CP06-448	Kinder Morgan Louisiana Pipeline LLC	14.00%
Apr-07	CP07-25	Questar Pipeline Company	11.75%
Apr-07	CP06-407	Missouri Interstate Gas	11.20%
Apr-07	CP06-89	WTG Hugoton, LP and Northern Natural Gas Co.	11.20%
Apr-07	CP06-471	Elba Express Co.	14.00%
May-07	CP07-44	Southeast Supply Header, LLC	13.50%
Jun-07	CP06-115	Texas Eastern Transmission LP	12.75%
Jun-07	CP00-6	Gulfstream Natural Gas Supply, L.L.C.	14.00%
Jun-07	CP07-14	Wyoming Interstate Co., Ltd.	12.50%
Jul-07	CP06-454	Kinder Morgan Illinois Pipeline LLC	13.00%
Jul-07	CP07-76	Sonora Pipeline, LLC	14.00%
Sep-07	CP07-32	Gulf South Pipeline LP	12.25%
Sep-07	CP05-91	Calhoun LNG/Point Comfort Pipeline, LP	14.00%
Dec-07	CP07-8	Guardian Pipeline, L.L.C.	14.00%
Jan-08	RP07-38	Eastern Shore Natural Gas Co.	13.60%
Apr-08	CP07-398	Gulf Crossing Pipeline LLC	13.50%
May-08	CP07-208	Rockies Express Pipeline LLC	13.00%
May-08	CP07-417	Texas Gas Transmission. LLC	11.50%
Jul-08	CP08-65	Midcontinent Express Pipeline LLC	13.00%
Jul-08	CP08-17	Cimarron River Pipeline LLC	11.20%
Jul-08	CP08-5	Southern Natural Gas Co.	12.00%

RISK PREMIUM - GAS PIPELINE ROE **Exhibit No. REC)-15**

ALLOWED ROE

Date	Docket No.	Company	Allowed ROE
Aug-08	CP08-65	Tennessee Gas Pipeline Co.	11.50%
Aug-08	CP08-398	White River Hub, LLC	13.00%
Sep-08	CP06-365	Bradwood Landing LLC/NorthernStar Energy LLC	14.00%
Sep-08	CP08-152	North Baja Pipeline LLC	14.00%
Nov-08	RP08-632	MarkWest Pioneer, L.L.C.	14.00%
Jan-09	CP07-62	AES Sparrows Point LNG/Mid-Atlantic Express L.L.C.	14.00%
Jan-09	RP04-274	Kern River Gas Transmission Co.	11.55%
Feb-09	CP09-3	T.W. Phillips Pipeline Corp.	14.00%
Jun-09	RP08-350	Southern Star Central Pipeline, Inc.	11.25%
Jun-09	CP08-429	Kern River Gas Transmission Co.	13.25%
Sep-09	CP09-54	Ruby Pipeline, L.L.C.	14.00%
Nov-09	CP09-17	Florida Gas Transmission Co.	13.00%
Nov-09	CP09-68	Texas Eastern Transmission, LP	12.75%
Dec-09	CP09-433	Fayetteville Express Pipeline LLC	14.00%
Dec-09	CP07-442	Pacific Connector Gas Pipeline, LP	14.00%
Apr-10	CP09-161	Bison Pipeline LLC	14.00%
Apr-10	CP09-460	ETC Tiger Pipeline	14.00%
May-10	CP09-444	Tennessee Gas Pipeline Co.	11.50%
Sep-10	CP10-14	Kern River Transmission Co.	11.55%
Nov-10	CP10-468	Northern Border Pipeline Co.	12.00%
Jan-11	CP10-194	Central New York Oil & Gas Co.	13.50%
Feb-11	RP08-306	Portland Natural Gas Transmission System	12.99%
Apr-11	CP11-19	Trunkline Gas Co., LLC	12.56%
Jul-11	CP09-54	Ruby Pipeline L.L.C.	14.00%
Nov-11	CP10-480	Central New York Oil & Gas Co.	13.50%
Jan-12	CP11-46	Kern River Gas Transmission Co.	11.55%
Feb-12	CP11-508	Texas Eastern Transmission, LP	12.75%
May-12	CP11-56	Texas Eastern Transmission, LP	12.75%
May-12	CP12-31	Southern LNG, L.L.C.	12.50%
Jun-12	CP12-4	Southern Natural Gas Co.-High Point Gas Trans.	12.99%
Jun-12	CP11-543	ANR Pipeline Co.-TC Offshore LLC	12.99%
Sep-12	CP13-21	Alliance Pipeline L.P.	12.99%
Mar-13	CP12-494	Gas Transmission Northwest	12.20%
Mar-13	RP10-729	Portland Natural Gas Transmission System	11.59%
May-13	CP12-490	Kinetica Energy Express, LLC	11.59%
Oct-13	RP10-1398	El Paso Natural Gas Co.	10.55%
Jun-14	CP13-73	Sierrita Gas Pipeline, LLC.	14.00%
Dec-14	CP14-68	Texas Eastern Transmission, LP	12.75%
Dec-14	CP13-499	Constitution Pipeline Co., LLC	14.00%
Dec-14	CP12-507	Cheniere Corpus Christi Pipeline, L.P.	14.00%
Apr-15	CP13-552	Creole Trail Pipeline, L.P.	14.00%
Nov-15	RP15-1310	National Fuel Gas Supply Corp.	11.30%
Dec-15	CP15-523	American Midstream, LLC	14.00%

Feb-16	CP14-554	Florida Southeast Connection, LLC	14.00%
Jun-16	CP16-35	First ECA Midstream LLC	10.55%

RISK PREMIUM - GAS PIPELINE ROE

REGRESSION RESULTS

Regression Statistics	
Multiple R	0.81278
R Square	0.66061
Adjusted R Square	0.62290
Standard Error	0.00598
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.000627	0.000627199	17.51847422	0.00235676
Residual	9	0.000322	3.58021E-05		
Total	10	0.000949			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.11977	0.01177	10.17894514	3.08653E-06	0.09315	0.14639	0.09315	0.14639
X Variable 1	-0.85198	0.20356	-4.185507641	0.00235676	-1.31246	-0.39151	-1.31246	-0.39151

ECAPM - HISTORICAL BOND YIELD

Exhibit No. RECO-16

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				**Market**										**Size**
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**	**Unadjusted RP**		**Beta Adjusted RP**			**Total**	**Empirical**	**Market**	**Size**	**Adjusted**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP*** [1]	**Beta**	**Weight**	***RP*** [2]	**RP**	**K_e**	**Cap**	**Adjustment**	**K_e**
1	ALLETE	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	9.75%	$3,192	1.49%	11.24%
2	Alliant Energy	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.70	75%	4.6%	6.8%	9.42%	$8,420	0.86%	10.28%
3	Ameren Corp.	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.65	75%	4.3%	6.5%	9.09%	$12,397	0.57%	9.66%
4	American Elec Pwr	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.65	75%	4.3%	6.5%	9.09%	$30,540	-0.36%	8.73%
5	Avangrid, Inc.	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	NA	75%	NA	NA	NA	$11,393	0.57%	NA
6	CenterPoint Energy	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.85	75%	5.6%	7.8%	10.41%	$10,470	0.57%	10.98%
7	Consolidated Edison	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.55	75%	3.6%	5.8%	8.43%	$20,234	0.57%	9.00%
8	DTE Energy Co.	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.65	75%	4.3%	6.5%	9.09%	$17,350	0.57%	9.66%
9	Duke Energy Corp.	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.60	75%	4.0%	6.2%	8.76%	$52,385	-0.36%	8.40%
10	Edison International	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.65	75%	4.3%	6.5%	9.09%	$22,869	-0.36%	8.73%
11	Eversource Energy	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.70	75%	4.6%	6.8%	9.42%	$17,010	0.57%	9.99%
12	OGE Energy Corp.	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.90	75%	5.9%	8.1%	10.74%	$6,708	0.86%	11.60%
13	PG&E Corp.	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.65	75%	4.3%	6.5%	9.09%	$30,316	-0.36%	8.73%
14	Pinnacle West Capital	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.70	75%	4.6%	6.8%	9.42%	$8,436	0.86%	10.28%
15	Sempra Energy	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	10.08%	$25,193	-0.36%	9.72%
16	Vectren Corp.	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	9.75%	$4,316	0.99%	10.74%
17	WEC Energy Group	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.60	75%	4.0%	6.2%	8.76%	$18,034	0.57%	9.33%
18	Xcel Energy Inc.	2.5%	8.9%	11.4%	2.6%	8.8%	25%	2.2%	0.60	75%	4.0%	6.2%	8.76%	$20,430	0.57%	9.33%
	Range of Reasonableness												**8.43% -- 10.74%**			**8.40% -- 11.60%**
	Midpoint												**9.59%**			**10.00%**
	Median												**9.09%**			**9.66%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Nov. 28, 2016).
(b) Average of weighted average earnings growth rates from IBES and Zacks for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Nov. 28, 2016) and www.zacks.com (retrieved Nov. 28, 2016).
(c) Six-month average yield on 30-year Treasury bonds for Jul. - Dec. 2016 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/htm.
(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(e) The Value Line Investment Survey (Oct. 28, Nov. 18, & Dec. 16, 2016).
(f) www.finance.yahoo.com (Jan. 9, 2017).
(g) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.

ECAPM - PROJECTED BOND YIELD **Exhibit No. RECO-16**

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market	Unadjusted RP		Beta Adjusted RP							Size
	Company	**Div Yield**	**Proj. Growth**	**Cost of Equity**	**Risk-Free Rate**	**Risk Premium**	**Weight**	***RP*[1]**	**Beta**	**Weight**	***RP*[2]**	**Total RP**	**Empirical K_e**	**Market Cap**	**Size Adjustment**	**Adjusted K_e**
1	ALLETE	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.75	75%	4.3%	6.3%	9.96%	$3,192	1.49%	11.45%
2	Alliant Energy	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.70	75%	4.0%	6.0%	9.67%	$8,420	0.86%	10.53%
3	Ameren Corp.	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.65	75%	3.8%	5.7%	9.38%	$12,397	0.57%	9.95%
4	American Elec Pwr	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.65	75%	3.8%	5.7%	9.38%	$30,540	-0.36%	9.02%
5	Avangrid, Inc.	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	NA	75%	NA	NA	NA	$11,393	0.57%	NA
6	CenterPoint Energy	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.85	75%	4.9%	6.8%	10.53%	$10,470	0.57%	11.10%
7	Consolidated Edison	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.55	75%	3.2%	5.1%	8.80%	$20,234	0.57%	9.37%
8	DTE Energy Co.	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.65	75%	3.8%	5.7%	9.38%	$17,350	0.57%	9.95%
9	Duke Energy Corp.	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.60	75%	3.5%	5.4%	9.09%	$52,385	-0.36%	8.73%
10	Edison International	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.65	75%	3.8%	5.7%	9.38%	$22,869	-0.36%	9.02%
11	Eversource Energy	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.70	75%	4.0%	6.0%	9.67%	$17,010	0.57%	10.24%
12	OGE Energy Corp.	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.90	75%	5.2%	7.1%	10.82%	$6,708	0.86%	11.68%
13	PG&E Corp.	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.65	75%	3.8%	5.7%	9.38%	$30,316	-0.36%	9.02%
14	Pinnacle West Capital	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.70	75%	4.0%	6.0%	9.67%	$8,436	0.86%	10.53%
15	Sempra Energy	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.80	75%	4.6%	6.5%	10.25%	$25,193	-0.36%	9.89%
16	Vectren Corp.	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.75	75%	4.3%	6.3%	9.96%	$4,316	0.99%	10.95%
17	WEC Energy Group	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.60	75%	3.5%	5.4%	9.09%	$18,034	0.57%	9.66%
18	Xcel Energy Inc.	2.5%	8.9%	11.4%	3.7%	7.7%	25%	1.9%	0.60	75%	3.5%	5.4%	9.09%	$20,430	0.57%	9.66%
	Range of Reasonableness												**8.80% -- 10.82%**			**8.73% -- 11.68%**
	Midpoint												**9.81%**			**10.21%**
	Median												**9.38%**			**9.95%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Nov. 28, 2016).
(b) Average of weighted average earnings growth rates from IBES and Zacks for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Nov. 28, 2016) and www.zacks.com (retrieved Nov. 28, 2016).
(c) Average yield on 30-year Treasury bonds for 2017-21 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Dec. 2, 2016); IHS Global Insight (Jan. 3, 2017); & Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 12 (Dec. 1, 2016).
(d) Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, Inc. at 190 (2006).
(e) The Value Line Investment Survey (Oct. 28, Nov. 18, & Dec. 16, 2016).
(f) www.finance.yahoo.com (Jan. 9, 2017).
(g) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.

DCF MODEL **Exhibit No. RECO-17**

NON-UTILITY GROUP

			(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Dividend Yield			Growth Rate			
	Company	Industry Group	6-Mo. Average	Adjustment	Adjusted	IBES	Zacks	Average	Cost of Equity
1	AT&T Inc.	Telecommunications	4.76%	1.0330	4.92%	8.40%	4.80%	6.60%	11.52%
2	Church & Dwight	Household Products	1.50%	1.0421	1.56%	7.68%	9.17%	8.43%	9.99%
3	Coca-Cola	Beverage	3.28%	1.0193	3.35%	1.84%	5.88%	3.86%	7.21%
4	Colgate-Palmolive	Household Products	2.19%	1.0437	2.29%	8.45%	9.03%	8.74%	11.03%
5	ConAgra Brands	Food Processing	2.14%	1.0523	2.26%	12.90%	8.00%	10.45%	12.71%
6	Gen'l Mills	Food Processing	2.92%	1.0372	3.03%	6.98%	7.90%	7.44%	10.47%
7	Hormel Foods	Food Processing	1.58%	1.0455	1.65%	7.79%	10.40%	9.10%	10.75%
8	Kellogg	Food Processing	2.65%	1.0327	2.74%	6.60%	6.47%	6.54%	9.27%
9	Kimberly-Clark	Household Products	3.01%	1.0375	3.12%	7.60%	7.40%	7.50%	10.62%
10	Lilly (Eli)	Drug Industry	2.66%	1.0533	2.80%	9.92%	11.40%	10.66%	13.46%
11	McDonald's Corp.	Restaurant	3.08%	1.0475	3.23%	9.63%	9.35%	9.49%	12.72%
12	PepsiCo, Inc.	Beverage	2.84%	1.0363	2.94%	7.17%	7.33%	7.25%	10.19%
13	Procter & Gamble	Household Products	3.12%	1.0401	3.24%	8.00%	8.04%	8.02%	11.26%
14	Public Storage	REIT	3.30%	1.0350	3.42%	8.30%	5.71%	7.01%	10.43%
15	Smucker (J.M.)	Food Processing	2.15%	1.0292	2.22%	4.91%	6.78%	5.85%	8.06%
16	Sysco Corp.	Wholesale Food	2.41%	1.0486	2.53%	10.83%	8.59%	9.71%	12.24%
17	Verizon Communic.	Telecommunications	4.41%	1.0157	4.48%	1.68%	4.58%	3.13%	7.61%
18	Wal-Mart Stores	Retail Store	2.80%	1.0170	2.85%	1.47%	5.31%	3.39%	6.24%
19	Waste Management	Environmental	2.48%	1.0504	2.60%	10.58%	9.56%	10.07%	12.67%
	Range of Reasonableness								**6.24% -- 13.46%**
	Midpoint								**9.85%**
	Median								**10.68%**

(a) Six-month average dividend yield for Jul. - Dec 2016.
(b) 1 + 0.5 x (f).
(c) (a) x (b).
(d) www.finance.yahoo.com (retrieved Jan. 4, 2017).
(e) www.zacks.com (retrieved Jan. 4, 2017).
(f) Average of (d) and (e).
(g) (c) + (f).

Appendix F

Attestation Required by 18 C.F.R. §35.13 (d)(6)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Rockland Electric Company) **Docket No. ER17-__-000**

ATTESTATION OF FRANCIS W. PEVERLY

I, Francis W. Peverly, Vice President - Operations, hereby attest, to the best of my knowledge, information, and belief, that the cost of service statements and supporting data submitted by RECO under 18 C.F.R. § 35.13(d) are true, accurate, and current representations of the utility's books, budgets, or other corporate documents.

Executed: January 9, 2017.

/s/ FW Peverly
Francis W. Peverly

Joann E. Dagele

JOANN E. DAGELE
Notary Public State of New York
No. 01D46005650
Qualified in Orange County
Commission Expires 4/20/ 2018

Appendix G

Period I and Period II Cost of Service Statements and Schedules

Rockland Electric Company
Statement AA
Balance Sheet
For the Year Ended December 31, 2015 (Period I)

	December 2016
UTILITY PLANT	
Electric Plant in Service	352,630,568.21
Construction Work in Progress	6,959,218.52
Plant Held for Future Use	208,709.29
Total Utility Plant	359,798,496.02
(Less) Accum. Prov. for Depr. Amort. Depl.	(83,854,397.81)
Net Utility Plant	275,944,098.21
Total	275,944,098.21
OTHER PROPERTY AND INVESTMENTS	
Investment in Subsidiary Companies	231,500.00
Total Other Property and Investments	231,500.00
CURRENT AND ACCRUED ASSETS	
Cash	(147,880.65)
Temporary Cash Investments	31,775,000.00
Customer Accounts Receivable	17,544,271.47
Other Accounts Receivable	1,079,735.63
(Less) Accum. Prov. for Uncollectible Acct.-Credit	(478,979.25)
Accounts Receivable from Assoc. Companies	11,335,295.73
Plant Materials and Operating Supplies	2,972,567.57
Nuclear Materials Held for Sale	0.00
Prepayments	1,378,935.62
Accrued Utility Revenues	8,791,631.98
Total Current and Accrued Assets	74,250,578.10
DEFERRED DEBITS	
Other Regulatory Assets	49,679,280.19
Miscellaneous Deferred Debits	708,493.74
Accumulated Deferred Income Taxes	9,781,386.40
Total Deferred Debits	60,169,160.33
Total Assets and Other Debits	410,595,336.64

	December 2016
PROPRIETARY CAPITAL	
Common Stock Issued	11,200,000.00
Retained Earnings	248,416,993.28
Total Proprietary Capital	259,616,993.28
LONG-TERM DEBT	
OTHER NONCURRENT LIABILITIES	
Accumulated Provision for Injuries and Damages	50,000.00
Total Other Noncurrent Liabilities	50,000.00
CURRENT AND ACCRUED LIABILITIES	
Accounts Payable	9,962,523.48
Accounts Payable to Associated Companies	8,299,314.01
Customer Deposits	6,310,542.58
Taxes Accrued	790,647.85
Interest Accrued	168,388.70
Tax Collections Payable	2,636.75
Miscellaneous Current and Accrued Liabilities	829,306.06
Derivative Instrument Liabilities	798,482.04
Derivative Instrument Liabilities - Hedges	0.00
Total Current and Accrued Liabilities	27,161,841.47
DEFERRED CREDITS	
Customer Advances for Construction	311,190.83
Accumulated Deferred Investment Tax Credits	349,937.80
Other Deferred Credits	616,910.88
Other Regulatory Liabilities	11,100,174.74
Accumulated Deferred Income Taxes-Other Property	82,785,332.58
Accumulated Deferred Income Taxes-Other	28,602,955.06
Total Deferred Credits	123,766,501.89
Total Liabilities and Other Credits	410,595,336.64

Rockland Electric Company
Statement AB
Income Statement
For the Year Ended December 31, 2015 (Period I)

Operating and Financial Income Statement

Rockland Electric Company

YTD

	December 2015
OPERATING REVENUES	
Revenue from Sales of Electric, Gas & Steam	194,516,566.01
Other Operating Revenues	(7,331,169.70)
TOTAL - OPERATING REVENUES	187,185,396.31
OPERATION AND MAINTENANCE	
Operating Expenses	
Purchased Power	102,042,306.01
Other Production Expenses	92.61
Transmission	1,779,986.51
Distribution	5,137,058.78
Customer Accounts	4,839,254.56
Customer Service	8,953,971.86
Sales Promotion	6,161.69
Administrative and General	20,058,581.55
Total - Operating Expenses	142,817,413.57
Maintenance Expenses	
Transmission	434,537.81
Distribution	11,155,560.24
Adminstrative and General	237,668.82
Total - Maintenance Expenses	11,827,766.87
TOTAL - OPERATION AND MAINTENANCE	154,645,180.44
Depreciation Expense	8,538,295.96
Amort. & Depl. of Utility Plant	20,215.94
Taxes Other Than Income Taxes	1,849,569.86
Income Taxes -- Federal and Other	10,802,566.94
Provision for Deferred Income Taxes	17,339,555.69
Provision for Deferred Income Taxes -Cr.	(19,342,041.22)
Investment Tax Credit Adj. -- Net	(55,935.00)
Total Utility Operating Expenses	173,797,408.61
NET UTILITY OPERATING INCOME	13,387,987.70
OTHER INCOME AND DEDUCTIONS	
Other Income	
Nonutility Operating Income	
Interest and Dividend Income	85,512.12
Allowance for Other Funds Used During Construction	529,707.22
Total Other Income	615,219.34
Other Income Deductions	
Total Other Income Deductions	130,969.46
Taxes Applic. to Other Income and Deductions	
Taxes Other Than Income Taxes	18,816.26
Income Taxes -- Federal and Other	(239,907.32)
Provision for Deferred Inc. Taxes	65,593.98
Provision for Deferred Income Taxes Credit	(69,008.68)
Total Taxes on Other Income and Deduct.	(224,505.76)
NET OTHER INCOME AND DEDUCTIONS	708,755.64
INTEREST CHARGES	
Other Interest Expense	56,440.61
Allowance for Borrowed Funds Used During Construction	(247,313.53)
NET INTEREST CHARGES	(190,872.92)
NET INCOME	14,287,616.26
Preferred Stock Dividend Requirements	0.00
NET INCOME APPLICABLE TO COMMON STOCK	14,287,616.26

Rockland Electric Company
Statement AC
Retained Earnings
For the Year Ended December 31, 2015 (Period I)

ROCKLAND ELECTRIC COMPANY - NJ OPERATIONS ONLY
RETAINED EARNINGS STATEMENT
STATEMENT OF COMPREHENSIVE INCOME
FOR THE PERIOD ENDING: YTD December 2015

	December 2015 YTD
RETAINED EARNINGS:	
Retained Earnings Beginning of the Year	222,116,986.27
Net Income	14,287,616.26
Common Stock Dividends	-
Retained Earnings Ending of Period	**236,404,602.53**
COMPREHENSIVE INCOME:	
Net Income	14,287,616.26
Other Comprehensive Income, Net of Tax:	
OCI - Other Comprehensive Income: Pension	-
OCI - Other Comprehensive Income: Opeb	-
Total Other Comprehensive Income/ (Loss), Net of Tax	**-**
Comprehensive Income	**14,287,616.26**

Rockland Electric Company
Statement AD
Cost of Plant
For the Year Ended December 31, 2015 (Period I)

Rockland Electric
Utility Plant
As of December 2015

Electric Plant	Current Year
Plant in Service	316,197,530.28
Plant Purchased or Sold	0.00
Plant Held for Future Use	2,261,631.88
Construction Work in Progress	21,129,428.70
Capital Lease Gas Turbine	0.00
Total Electric Plant in Service	339,588,590.86
Total Utility Plant	339,588,590.86

ROCKLAND ELECTRIC COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

YTD 2015

ACCUMULATED DEPRECIATION AN	ELECTRIC PLANT IN SERVICE	ELECTRIC PLANT HELD FOR FUTURE USE	TOTAL
Balance Beginning of Period	**$ 73,049,917.40**	$ -	**$ 73,049,917.40**
Provision for Depreciation and Amortization Charged to:			
Depreciation Expenses-Electric	8,558,512.00		8,558,512.00
Depreciation Expenses-Electric Plant Held For Future Use			
Total Provision	8,558,512.00	-	8,558,512.00
Retirement - Book Cost of Retirement	3,156,033.38		3,156,033.38
- Cost of Removal	1,204,120.23		1,204,120.23
- Salvage	-		-
Net Retirement	4,360,153.61	-	4,360,153.61
RWIP	49,034.62		49,034.62
Transfers and Adjustments	23,719.31		23,719.31
Net Amount to Reserve	4,173,043.08	-	4,173,043.08
Balance at End of Period	**$ 77,222,960.48**	$ -	**$ 77,222,960.48**

Rockland Electric Company
Statement AF
Specified Deferred Credits
For the Year Ended December 31, 2015 (Period I)

Specified Deferred Credits

Period 1: Year Ended December 31, 2015

Acct 255

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year	Actual Balance Current Month Prior Year
DEC-15	Rockland Electric Company	23010	ACCUM DEFER INVEST TAX CREDIT	($401,285.80)	($457,220.80)
Grand Total				**($401,285.80)**	**($457,220.80)**
			Average of Beginning & Ending Balance		($429,253.30)

Acct 2810

N/A

Acct 2820

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year	Actual Balance Current Month Prior Year
DEC-15	Rockland Electric Company	12234	ACCUM DEFER FIT 282 CURRENT	$0.00	$101,553.00
		19999	SUSPENSE ACCOUNT FOR POSTING APPLICATIONS	$0.00	$0.00
		22503	DEFER FIT NONCURRENT	($6,185,101.29)	($6,185,101.29)
		22504	DEFER SIT NONCURRENT	($5,119.20)	($5,119.20)
		22515	ACCUMULATED DEFERRED FIT - 282 - NONCURRENT	($41,034,528.57)	($40,399,323.51)
		22518	ACCUMULATED DEFERRED SIT - 282 - NONCURRENT	($8,680,530.11)	($7,992,759.15)
		22551	DEFER FEDERAL INCOME TAX UNFUNDED	($11,796,948.60)	($11,796,948.60)
		22553	ACCUM DEFER FIT 282 UNFUNDED PLANT	($2,741,831.45)	($2,308,222.72)
		22556	ACCUM DEFER SIT 282 UNFUNDED PLANT	($1,316,634.00)	($1,316,634.00)
		22560	ACCUM DEFER FIT 283 GROSSUP	($469,034.77)	($469,034.77)
		22561	ACCUM DEFER SIT 190 GROSSUP	($1,299,996.00)	($1,299,996.00)
		22562	ACCUM DEFER SIT 283 GROSSUP	$399,719.00	$399,719.00
		23006	DEFER FIT LONG TERM	$3,216.00	$3,216.00
Grand Total				**($73,126,788.99)**	**($71,268,651.24)**
			Average of Beginning & Ending Balance		($72,197,720.12)

Acct 2830

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year	Actual Balance Current Month Prior Year
DEC-15	Rockland Electric Company	12235	ACCUM DEFER FIT 283 CURRENT	$0.00	$2,224,624.97
		12238	ACCUM DEFER SIT 283 CURRENT	$0.00	$628,622.42
		19999	SUSPENSE ACCOUNT FOR POSTING APPLICATIONS	$0.00	$0.00
		21871	DEFER FIT CURRENT	($1,528,175.95)	($1,528,175.95)
		21885	UNCERTAIN FIT CURRENT	$0.00	$0.00
		21886	UNCERTAIN SIT CURRENT	$0.00	$0.00
		22503	DEFER FIT NONCURRENT	($12,918,891.85)	($11,466,693.84)
		22504	DEFER SIT NONCURRENT	$1,310,083.86	$1,802,815.44
		22514	ACCUMULATED DEFERRED FIT - 190 - NONCURRENT	($556,882.42)	$0.00
		22515	ACCUMULATED DEFERRED FIT - 282 - NONCURRENT	($101,552.00)	($101,552.00)
		22516	ACCUMULATED DEFERRED FIT - 283 - NONCURRENT	($5,625,584.99)	($8,254,535.28)
		22517	ACCUMULATED DEFERRED SIT - 190 - NONCURRENT	($74,979.00)	($74,979.00)
		22518	ACCUMULATED DEFERRED SIT - 282 - NONCURRENT	($0.13)	($0.13)
		22519	ACCUMULATED DEFERRED SIT - 283 - NONCURRENT	($1,971,904.19)	($2,705,974.00)
		22551	DEFER FEDERAL INCOME TAX UNFUNDED	($6,739,053.24)	($6,739,053.14)
		22555	ACCUM DEFER FIT 283 UNFUNDED NONPLANT	$253,544.81	$284,703.50
		22558	ACCUM DEFER SIT 283 UNFUNDED NONPLANT	$0.01	$0.00
		22560	ACCUM DEFER FIT 283 GROSSUP	($1,408,389.71)	($1,087,413.39)
		22562	ACCUM DEFER SIT 283 GROSSUP	$0.00	$0.00
		23006	DEFER FIT LONG TERM	$268,278.45	$250,778.45
		23015	DEFER SIT LONG TERM	($4,167,922.90)	($4,167,922.90)
Grand Total				**($33,261,429.25)**	**($30,934,754.85)**
			Average of Beginning & Ending Balance		($32,098,092.05)

Rockland Electric Company
Statement AG
Specified Plant Accounts and Deferred Debits
For the Year Ended December 31, 2015 (Period I)

Period 1: Year Ended December 31, 2015

Acct 1050

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year	Actual Balance Current Month Prior Year
DEC-15	Rockland Electric Company	14001	UTILITY PLANT	$2,261,631.88	$2,256,270.25
Grand Total				**$2,261,631.88**	**$2,256,270.25**

Average of Beginning & Ending Balance $2,258,951.07

Acct 1070

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year
DEC-14	Rockland Electric Company	14021	CWIP	$6,601,903.09
JAN-15	Rockland Electric Company	14021	CWIP	$7,814,167.53
FEB-15	Rockland Electric Company	14021	CWIP	$8,453,401.67
MAR-15	Rockland Electric Company	14021	CWIP	$8,677,175.54
APR-15	Rockland Electric Company	14021	CWIP	$9,883,391.09
MAY-15	Rockland Electric Company	14021	CWIP	$11,916,580.84
JUN-15	Rockland Electric Company	14021	CWIP	$11,466,508.05
JUL-15	Rockland Electric Company	14021	CWIP	$12,114,012.96
AUG-15	Rockland Electric Company	14021	CWIP	$13,353,010.09
SEP-15	Rockland Electric Company	14021	CWIP	$15,068,078.75
OCT-15	Rockland Electric Company	14021	CWIP	$16,072,958.38
NOV-15	Rockland Electric Company	14021	CWIP	$18,908,898.23
DEC-15	Rockland Electric Company	14021	CWIP	$21,129,428.70

13-Month Average $ 12,299,487.42

Acct 1201
N/A

Acct 1820
N/A

Acct 190

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year	Actual Balance Current Month Prior Year
DEC-15	Rockland Electric Company	12230	DEFER FIT CURRENT	$0.00	$0.00
		12231	DEFER SIT CURRENT	$0.00	$0.00
		12233	ACCUM DEFER FIT 190 CURRENT	$0.00	$496,485.56
		12236	ACCUM DEFER SIT 190 CURRENT	$0.00	($52,510.00)
		21871	DEFER FIT CURRENT	$0.00	$0.00
		21872	DEFER SIT CURRENT	$0.00	$0.00
		22503	DEFER FIT NONCURRENT	$4,731,546.14	$4,731,546.14
		22504	DEFER SIT NONCURRENT	($257,468.67)	($257,468.67)
		22513	DEFER TAX ASSET UNCERTAIN BENEFIT FEDERAL OFFSET	$247,161.43	$1,037,633.96
		22514	ACCUMULATED DEFERRED FIT - 190 - NONCURRENT	$2,699,615.39	($1,390,959.38)
		22516	ACCUMULATED DEFERRED FIT - 283 - NONCURRENT	($18,840.00)	($18,840.00)
		22517	ACCUMULATED DEFERRED SIT - 190 - NONCURRENT	($390,657.50)	($1,637,565.52)
		22551	DEFER FEDERAL INCOME TAX UNFUNDED	($234,799.21)	($234,799.21)
		22554	ACCUM DEFER FIT 190 UNFUNDED NONPLANT	$274,881.15	$307,358.51
		22559	ACCUM DEFER FIT 190 GROSSUP	$189,837.61	$212,267.03
		22560	ACCUM DEFER FIT 283 GROSSUP	$158,898.00	$158,898.00
		23005	AUTO DEPOSIT REFUND ADJ DUE CUSTOMER	$0.00	$226,242.10
		23006	DEFER FIT LONG TERM	$126.65	$126.65
		23015	DEFER SIT LONG TERM	$817,000.00	$817,000.00
		23017	ACCUMULATED DEFERRED FIT OCI PENSION RELATED	($11,091.41)	($11,091.41)
		23018	ACCUMULATED DEFERRED SIT OCI PENSION RELATED	($3,128.35)	($3,128.35)
Grand Total				**$8,203,081.23**	**$4,381,195.41**

Average of Beginning & Ending Balance $6,292,138.32

Rockland Electric Company
Statement AH
O&M Expenses
9 For the Year Ended December 31, 2015 (Period I)

Rockland Electric Company
Operating and Maintenance - Electric
December, 2015

FERC or Natural Account Description	FERC or Natural Account Number	Month 2015	Month 2014	Month Variance	YTD 2015	YTD 2014	YTD Variance
Power Production Expenses	0200						
Hydraulic Power Generation Electric	0302	0.00	0.00	0.00	92.61	0.00	92.61
Operations	0535	0.00	0.00	0.00	92.61	0.00	92.61
Operation Supplies And Expenses	5401	0.00	0.00	0.00	92.61	0.00	92.61
Other Power Supply Expenses Electric	0304	7,171,748.70	7,050,672.91	121,075.79	102,042,306.01	93,434,293.50	8,608,012.51
Purchased Power	5550	7,171,748.70	7,050,672.91	121,075.79	102,042,306.01	93,434,293.50	8,608,012.51
System Control And Load Dispatching	5560	0.00	0.00	0.00	0.00	0.00	0.00
Other Expenses	5570	0.00	0.00	0.00	0.00	0.00	0.00
Total - Operation		$7,171,748.70	$7,050,672.91	$121,075.79	$102,042,398.62	$93,434,293.50	$8,608,105.12
Total - Maintenance		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Power Production Expenses		$7,171,748.70	$7,050,672.91	$121,075.79	$102,042,398.62	$93,434,293.50	$8,608,105.12
Transmission Expenses Electric	0210						
Operations	0305	75,668.42	134,823.88	(59,155.46)	1,690,875.14	1,910,177.03	(219,301.89)
Operation Supervision And Engineering	5600	22,237.12	55,416.26	(33,179.14)	307,009.54	693,846.33	(386,836.79)
Load Dispatch Reliability	5611	0.00	0.00	0.00	0.00	0.00	0.00
Scheduling,System Control & Dispatching Services	5614	3,988.82	5,402.75	(1,413.93)	44,775.89	63,806.38	(19,030.49)
Lt Reliab Plann & Standards Devel Svcs	5618	1,150.87	1,558.81	(407.94)	12,918.95	15,979.01	(3,060.06)
Station Expenses	5620	10,611.80	29,618.51	(19,006.71)	410,510.73	329,328.48	81,182.25
Overhead Line Expenses	5630	353.31	(16,888.66)	17,241.97	123,740.61	91,471.87	32,268.74
Miscellaneous Transmission Expenses	5660	43,803.00	59,716.21	(15,913.21)	591,925.65	594,778.71	(2,853.06)
Rents	5670	(6,476.50)	0.00	(6,476.50)	199,993.77	120,966.25	79,027.52
Maintenance	0306	6,752.53	234,032.43	(227,279.90)	434,537.81	996,609.40	(562,071.59)
Maintenance Of Structures Transmission	5690	0.00	0.00	0.00	0.00	0.01	(0.01)
Maintenance Of Station Equipment Transmission	5700	(701.11)	17,182.83	(17,883.94)	(14,655.65)	46,966.56	(61,622.21)
Maintenance Of Overhead Lines Transmission	5710	7,453.64	216,849.60	(209,395.96)	449,193.46	949,642.83	(500,449.37)
Maintenance Of Underground Lines Transmission	5720	0.00	0.00	0.00	0.00	0.00	0.00
Total Transmission Expenses		$82,420.95	$368,856.31	$(286,435.36)	$2,125,412.95	$2,906,786.43	$(781,373.48)
Regional/Market Expenses Electric	0220						
Operations	0307	7,938.39	10,752.36	(2,813.97)	89,111.37	112,495.66	(23,384.29)
Market Facilitation, Monitoring And Compliance Services	5757	7,938.39	10,752.36	(2,813.97)	89,111.37	112,495.66	(23,384.29)
Total Regional / Market Expenses		$7,938.39	$10,752.36	$(2,813.97)	$89,111.37	$112,495.66	$(23,384.29)
Distribution Expenses Electric	0230						
Operations	0399	440,118.39	416,613.36	23,505.03	5,137,058.78	3,923,181.92	1,213,876.86
Operation Supervision And Engineering	5800	144,448.18	110,341.77	34,106.41	1,479,270.72	1,226,522.61	252,748.11

Rockland Electric Company
Operating and Maintenance - Electric
December, 2015

FERC or Natural Account Description	FERC or Natural Account Number	Month 2015	Month 2014	Month Variance	YTD 2015	YTD 2014	YTD Variance
Load Dispatching	5810	492.19	492.19	0.00	5,906.28	(15,258.05)	21,164.33
Station Expenses	5820	24,316.32	45,479.29	(21,162.97)	424,724.80	350,068.07	74,656.73
Overhead Line Expenses	5830	18,051.79	26,134.72	(8,082.93)	254,938.11	254,054.14	883.97
Underground Line Expenses	5840	13,826.96	12,267.11	1,559.85	159,294.45	109,787.43	49,507.02
Street Lighting And Signal System Expenses	5850	0.00	0.00	0.00	0.00	0.00	0.00
Meter Expenses	5860	(2,439.30)	9,637.46	(12,076.76)	130,457.83	199,139.98	(68,682.15)
Customer Installations Expenses	5870	0.00	0.00	0.00	0.00	6,641.53	(6,641.53)
Miscellaneous Distribution Expenses	5880	233,013.25	210,260.82	22,752.43	2,648,788.91	1,781,926.57	866,862.34
Rents	5890	8,409.00	2,000.00	6,409.00	33,677.68	10,299.64	23,378.04
Maintenance	0400	831,794.78	822,469.39	9,325.39	11,155,560.24	8,056,867.31	3,098,692.93
Maintenance Of Structures Distribution	5910	0.00	0.00	0.00	0.00	0.00	0.00
Maintenance Of Station Equipment Distribution	5920	3.39	624.63	(621.24)	29,791.53	25,927.38	3,864.15
Maintenance Of Overhead Lines Distribution	5930	799,468.76	792,154.23	7,314.53	10,524,037.05	7,251,982.77	3,272,054.28
Maintenance Of Underground Lines Distribution	5940	24,848.41	(8,120.41)	32,968.82	390,483.91	531,839.79	(141,355.88)
Maintenance Of Line Transformers	5950	0.00	0.00	0.00	0.00	0.00	0.00
Maintenance Of Street Lighting And Signal Systems	5960	7,474.22	37,810.94	(30,336.72)	211,247.75	247,117.37	(35,869.62)
Maintenance Of Meters	5970	0.00	0.00	0.00	0.00	0.00	0.00
Total Distribution Expenses		$1,271,913.17	$1,239,082.75	$32,830.42	$16,292,619.02	$11,980,049.23	$4,312,569.79
Customer Accounts Expenses	0079						
Customer Account Operation	0288	422,788.06	282,376.42	140,411.64	4,839,254.56	4,421,018.57	418,235.99
Supervision	9010	0.00	0.00	0.00	0.00	0.00	0.00
Meter Reading Expenses	9020	78,678.48	88,787.06	(10,108.58)	877,057.50	719,193.86	157,863.64
Customer Records And Collection Expenses	9030	220,646.61	246,709.56	(26,062.95)	3,419,516.97	3,576,132.28	(156,615.31)
Uncollectible Accounts	9040	2,598.75	(54,141.10)	56,739.85	400,278.88	110,936.32	289,342.56
Miscellaneous Customer Accounts Expenses	9050	120,864.22	1,020.90	119,843.32	142,401.21	14,756.11	127,645.10
Customer Service And Informational Expenses	0081						
Customer Service Operation	0290	580,176.18	737,842.55	(157,666.37)	8,953,971.86	11,830,853.12	(2,876,881.26)
Customer Service And Informational Expenses (Non Major)	9060	(107,734.00)	8,239.00	(115,973.00)	0.00	700,692.00	(700,692.00)
Customer Assistance Expenses	9080	616,531.54	0.00	616,531.54	8,164,417.29	0.00	8,164,417.29
Informational And Instructional Advertising Expenses	9090	11,136.77	11,225.51	(88.74)	66,156.45	74,997.27	(8,840.82)
Miscellaneous Customer Service And Informational Expenses	9100	60,241.87	718,378.04	(658,136.17)	723,398.12	11,055,163.85	(10,331,765.73)
Sales Expenses	0083						
Sales Operation	0291	312.74	528.66	(215.92)	6,161.69	2,158.52	4,003.17
Supervision	9110	227.82	462.06	(234.24)	1,721.60	1,163.12	558.48
Demonstrating And Selling Expenses	9120	84.92	66.60	18.32	4,440.09	995.40	3,444.69
Advertising Expenses	9130	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous Sales Expenses	9160	0.00	0.00	0.00	0.00	0.00	0.00
Sales Expenses	9170	0.00	0.00	0.00	0.00	0.00	0.00
Administrative And General Expenses	0085						
Administrative And General Operation	0293	1,455,739.25	2,169,761.28	(714,022.03)	20,058,581.55	20,664,730.37	(606,148.82)
Administrative And General Salaries	9200	157,196.97	526,616.25	(369,419.28)	3,142,041.26	2,932,944.33	209,096.93

Rockland Electric Company
Operating and Maintenance - Electric
December, 2015

FERC or Natural Account Description	FERC or Natural Account Number	Month 2015	Month 2014	Month Variance	YTD 2015	YTD 2014	YTD Variance
Office Supplies And Expenses	9210	(14,485.71)	2,104.69	(16,590.40)	176,081.22	286,359.70	(110,278.48)
Administrative Expenses Transferred Credit	9220	201,537.69	317,478.64	(115,940.95)	3,039,943.15	3,317,341.97	(277,398.82)
Outside Services Employed	9230	80,979.44	75,681.45	5,297.99	296,538.68	403,951.82	(107,413.14)
Property Insurance	9240	7,113.71	7,187.61	(73.90)	84,828.84	86,612.00	(1,783.16)
Injuries And Damages	9250	15,829.93	(4,842.51)	20,672.44	267,050.68	316,505.68	(49,455.00)
Other Employee Benefits Expenses	9260	31,095.06	29,403.72	1,691.34	553,828.53	(114,593.35)	668,421.88
Health And Life Expenses	9261	148,154.51	291,193.43	(143,038.92)	2,099,413.19	2,913,990.33	(814,577.14)
Pension Expense	9262	592,803.00	597,265.59	(4,462.59)	6,771,930.76	6,346,331.73	425,599.03
Other Post Retirement Benefit Expense	9263	(51,771.12)	2,995.19	(54,766.31)	(638,313.88)	1,176,979.03	(1,815,292.91)
Regulatory Commission Expenses	9280	(15,809.43)	80,725.52	(96,534.95)	812,050.82	825,035.78	(12,984.96)
Duplicate Charges Credit	9290	(11,550.27)	(194,926.33)	183,376.06	(114,104.25)	(205,375.15)	91,270.90
General Advertising Expenses	9301	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous General Expenses	9302	52,417.82	173,622.25	(121,204.43)	394,999.41	(264,198.35)	659,197.76
General Rents	9310	262,227.65	265,255.73	(3,028.13)	3,172,293.14	2,642,844.85	529,448.29
Transportation Expenses	9330	0.00	0.00	0.00	0.00	0.00	0.00
Administrative And General Maintenance	0295	16,709.86	14,994.36	1,715.50	237,668.82	260,417.96	(22,749.14)
Maintenance Of General Plant	9350	16,709.86	14,994.36	1,715.50	237,668.82	260,417.96	(22,749.14)
Total - Operation		$2,459,016.23	$3,190,508.91	$(731,492.58)	$33,857,969.66	$36,918,760.58	$(3,060,790.92)
Total - Maintenance		$16,709.86	$14,994.36	$1,715.50	$237,668.82	$260,417.96	$(22,749.14)
Total Other Expenses		$2,475,726.09	$3,205,503.27	$(729,777.18)	$34,095,638.48	$37,179,178.54	$(3,083,540.06)
Grand Total		$11,009,747.30	$11,874,867.60	$(865,120.30)	$154,645,180.44	$145,612,803.36	$9,032,377.08

Rockland Electric Company
Statement AI
Wages and Salaries
For the Year Ended December 31, 2015 (Period I)

Name of Respondent	This Report is:	Date of Report	Year of Report
Rockland Electric Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/2015

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	32		
4	Transmission	634,309		
5	Distribution	2,297,279		
6	Customer Accounts	2,481,452		
7	Customer Service and Informational	643,551		
8	Sales	-		
9	Administrative and General	1,220,461		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	**7,277,084**		
11	Maintenance			
12	Production	0		
13	Transmission	140,874		
14	Distribution	2,116,024		
15	Administrative and General	-		
16	TOTAL Maint. (Total of lines 12 thru 15)	**2,256,899**		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	32		
19	Transmission (Enter Total of lines 4 and 13)	775,184		
20	Distribution (Enter Total of lines 5 and 14)	4,413,303		
21	Customer Accounts (Transcribe from line 6)	2,481,452		
22	Customer Service and Informational	643,551		
23	Sales (Transcribe from line 8)	-		
24	Administrative and General (Enter Total of lines 9 and 15)	1,220,461		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	**9,533,983**	-	9,533,983
26	Gas			
27	Operation			
28	Production - Manufactured Gas			
29	Production - Natural Gas (Including Expl. and Dev.)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing	0		
32	Transmission	0		
33	Distribution	0		
34	Customer Accounts	0		
35	Customer Service and Informational	0		
36	Sales	-		
37	Administrative and General	0		
38	TOTAL Operation (Enter Total of lines 28 thru 37)	**0**		
39	Maintenance			
40	Production - Manufactured Gas			
41	Production - Nat. Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing	0		
44	Transmission	0		
45	Distribution	0		
46	Administrative and General	-		
47	TOTAL Maint. (Enter Total of lines 40 thru 46)	**0**		

Name of Respondent Rockland Electric Company	This Report is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2015

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
	Gas (Continued)			
48	Total Operation and Maintenance			
49	Production - Manufactured Gas (Enter Total of lines 28 and 40)	-		
50	Production - Nat. Gas (Including Expl. and Dev.) (Total of lines 29 and 41)	-		
51	Other Gas Supply (Enter Total of lines 30 and 42)	-		
52	Storage, LNG Terminaling and Processing (Total of lines 31 and 43)	0		
53	Transmission (Lines 32 and 44)	0		
54	Distribution (Lines 33 and 45)	0		
55	Customer Accounts (Line 34)	0		
56	Customer Service and Informational (Line 35)	0		
57	Sales (Line 36)	-		
58	Administrative and General (Lines 37 and 46)	0		
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)	**0**	-	0
60	Other Utility Departments			
61	Operation and Maintenance	0	-	0
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	**9,533,983**	-	9,533,983
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	4,350,411	-	4,350,411
66	Gas Plant	0	-	0
67	Other	32	-	32
68	TOTAL Construction (Total of lines 65 thru 67)	**4,350,443**	-	**4,350,443**
69	Plant Removal (By Utility Departments)			
70	Electric Plant	546,930	-	546,930
71	Gas Plant	0	-	0
72	Other	0	-	0
73	TOTAL Plant Removal (Total of lines 70 thru 72)	**546,930**	-	**546,930**
74	Other Accounts (Specify):			
75				
76				
77				
78	Billing Projects		768,838	768,838
79				
80	Regulatory Assets		17,331	17,331
81	Other		50,902	50,902
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	0	837,072	837,071
96	TOTAL SALARIES AND WAGES	14,431,355	837,072	15,268,426

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Rockland Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant					
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	1,067,506				1,067,506
8	Distribution Plant	7,051,228				7,051,228
9	Regional Transmission and Market Operation					
10	General Plant	419,562		20,216		439,778
11	Common Plant-Electric					
12	TOTAL	8,538,296		20,216		8,558,512

B. Basis for Amortization Charges

Account 404 - General Plant - Saddle River - Remaining life amortization.
Account 405 - Intangible Plant - Computer Software - Amortized at a rate of 20% per year.

Rockland Electric Company
Statement AJ
Depreciation and Amortization
For the Year Ended December 31, 2015 (Period I)

Rockland Electric Company
Statement AK
Taxes Other than Income Taxes
For the Year Ended December 31, 2015 (Period I)

ROCKLAND ELECTRIC COMPANY
DETAIL OF TAX EXPENSE - OPERATING - ELECTRIC
AS OF December 31, 2015

OPERATING TAXES	December 2015 Electric
TAXES OTHER THAN INCOME TAXES	
55301 - PROPERTY TAXES	166,935.72
55302 - STATE AND LOCAL TAXES ON REVENUE	-
55303 - PAYROLL TAXES	34,427.03
55304 - SALES AND USE TAX	(4,119.38)
55305 - OTHER TAXES	451.29
55306 - MTA TAX SURCHARGE	-
55307 - PROPERTY TAX DEFERRAL	-
55308 - PUBLIC UTILITY GROSS TAX	-
55309 - TAXES OTHER STATE	-
55310 - TAXES OTHER FEDERAL	-
55311 - SUBSIDIARY CAPITAL TAX	-
55312 - CORPORATE FRANCHISE TAX	-
55313 - STATE OPERATIONAL USE TAX	-
55314 - LOCAL OPERATIONAL USE TAX	-
55315 - LOCAL SALES AND USE TAX RESERVE	-
55316 - STATE SALES AND USE TAX RESERVE	-
55317 - OPR TAX LOC PUB UTIL TAX RESERVE	-
55318 - OPR TAX STATE VEHICLE REG TAX RESERVE	-
55319 - OPR TAX STATE ENVIRON DISTRIBUTION	-
55320 - TEFA TAX EXPENSE	-
Total Taxes Other Than Income Taxes	197,694.66

Rockland Electric Company
Statement AL
Working Capital
For the Year Ended December 31, 2015 (Period I)
($000s)

Materials and Supplies	2,934	
Prepayments	2,767	
Net Cash Working Capital	8,885	LATEST LEAD LAG (Case ER09080668 - effective 5/10) Exhibit P-3
Total	14,587	

Rockland Electric Company
Statement AM
Construction Work-in-Progress
For the Year Ended December 31, 2015 (Period I)

Period 1: Year Ended December 31, 2015

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year
DEC-14	Rockland Electric Company	14021	CWIP	$6,601,903.09
JAN-15	Rockland Electric Company	14021	CWIP	$7,814,167.53
FEB-15	Rockland Electric Company	14021	CWIP	$8,453,401.67
MAR-15	Rockland Electric Company	14021	CWIP	$8,677,175.54
APR-15	Rockland Electric Company	14021	CWIP	$9,883,391.09
MAY-15	Rockland Electric Company	14021	CWIP	$11,916,580.84
JUN-15	Rockland Electric Company	14021	CWIP	$11,466,508.05
JUL-15	Rockland Electric Company	14021	CWIP	$12,114,012.96
AUG-15	Rockland Electric Company	14021	CWIP	$13,353,010.09
SEP-15	Rockland Electric Company	14021	CWIP	$15,068,078.75
OCT-15	Rockland Electric Company	14021	CWIP	$16,072,958.38
NOV-15	Rockland Electric Company	14021	CWIP	$18,908,898.23
DEC-15	Rockland Electric Company	14021	CWIP	$21,129,428.70

13 Month Average **$ 12,299,487.42**

ROCKLAND ELECTRIC COMPANY
NOTES PAYABLE
AS OF December 31, 2015

BANK	INTEREST %	AMOUNT $
		$0.00
	TOTAL NOTES PAYABLE	$0.00

Rockland Electric Company
Statements AO
Rate for allowance for funds used during construction
For the Year Ended December 31, 2015 (Period I)

We will be seeking a waiver for Statements AO.

Rockland Electric Company
Statement AP
Federal Income Tax Deduction - Interest
For the Year Ended December 31, 2015 (Period I)

Line No.			(Income)/Expense ($000s) For the Year Ended December 31,2015
1	Interest deducted on federal tax return		$ (584,514)
2	Interest expense consist of the following:		
	(1) interest on RECO's long-term debt	$ -	
	(2) other interest expense.	$ (584,514)	
		$ (584,514)	

Note: Consolidated Edison, Inc. files a consolidated federal tax return of which RECO is part of it.

Rockland Electric Company
Statement AQ
Federal Income Tax Deduction - Other than Interest
For the Year Ended December 31, 2015 (Period I)

Line No.						($000s) For the Year Ended December 31,2015	
1	Officer Compensation				$	260,407	
2	Salaries and wages				$	2,790,485	
3	Repairs and maintenance				$	17,384,619	
4	Bad debts				$	89,025	
5	Rents				$	3,172,293	
6	Taxes and licenses				$	2,664,763	
7	Depreciation				$	4,742,930	
8	Pension, profit-sharing, etc., plans				$	11,398,050	
9	Employee benefit programs				$	(2,440,285)	
10	Other deductions as follows:				$	19,489,207	(A)
	a)	Administrative & General	$	1,000,584			
	b)	Other Production Expenses		93			
	c)	Transmission Expenses		1,445,038			
	d)	Distribution Expenses		5,137,059			
	e)	I/C Expenses		201,061			
	f)	Customer Expenses		4,839,255			
	g)	Insurance Expenses		84,829			
	h)	Storm Expense		(7,387,164)			
	i)	Other Deductions		(7)			
	j)	Outside Services		296,539			
	k)	Promotions		12,072,697			
	l)	Directors Services		11,375			
	m)	Office Supplies and Expenses		176,081			
	n)	Regulatory Commission Expenses		1,344,716			
	o)	Injuries and Damages		267,051			
			$	19,489,207	(A)		

Note: Consolidated Edison, Inc. files a consolidated federal tax return of which RECO is part of it.

Rockland Electric Company
Statement AR
Federal Tax Adjustments
For the Year Ended December 31, 2015 (Period I)

Net Income For The Year		**14,287,616**
ADD: TAXABLE INCOME NOT REPORTED ON BOOKS:		
Avoided Interest Capitalized Fed	505,739	
Contribution In Aid of Construction	230,029	
		735,768
ADD: DEDUCTION PER BOOKS NOT DEDUCTED FOR RETURN:		
Federal Income Tax	6,510,375	
Excess Tax Over Book Depreciation	54,243	
Increase in Rabbi Trust - SERP	364,821	
Interest on IRS Audit	47,808	
OPEB Cost Retiree - Funding v. Expense - Fed	996,979	
Stock Plans	175,704	
BGS / ECA Undercollection Fed	1,320,441	
Storm Damage Deferred On Books State	7,387,164	
Supplemental Pension Fed	291,127	
Reserve for Deferred Costs	1,506	
TBC Expense Amort - Securitization	3,832,156	
TBC Tax - Securitization	2,530,722	
Unallowable Book Pension Expense - Fed	6,155,204	
Smart Grid Maintenance Costs	384,257	
		30,052,509
DEDUCT: INCOME PER BOOKS NOT INCLUDED ON RETURN:		
AFUDC Borrowed Funds Fed	247,314	
AFUDC Equity	529,707	
		777,021
DEDUCT: EXPENSE PER RETURN NOT CHARGED TO BOOKS:		
Bad Debts Fed	89,025	
Change of Accounting Section 263A Fed	1,758,233	
Cost of Removal	1,201,603	
DSM Program Fed	1,321,885	
Gas Hedging Realized and Deferred Loss	922,475	
Loss on Disposition of Property Fed	97,692	
Materials and Supplies Deduction (Tang Prop Regs)	1,573,866	
Pension Funding - Federal	6,498,603	
Proceeds From COLI - Officers	1,038,008	
Repair Allowance	1,495,072	
Rate Case Cost	532,665	
Revenue Subject to Refund - Transformers	101	
State Income Tax	221,320	
System Benefit Charges	1,790,678	
Workmens Compensation Fed	92,792	
		18,634,018
TAXABLE INCOME OR (LOSS)		**25,664,854**
Federal Tax Before Adjustments @ 35%		8,982,699
Tax Credits & Adjustments:		
Prior Period Adjustment		(634,851)
Federal Income Tax		**8,347,848**

Basis of Allocation

Respondent is included in the consolidated Federal Income Tax Return filed by Consolidated Edison, Inc., which includes its wholly owned subsidiaries. Federal income tax liability is allocated on the basis of each member's United States Federal tax liability. Income Tax liability of each member will be no more than if it were to file an individual tax return. This is in accordance with IRC Section 1552 and Treasury Regulation 1.1502-33(d)(3) and 1.1552-1(a)(2)

Rockland Electric Company
Statement AS
Additional State Income Tax Deductions
For the Year Ended December 31, 2015 (Period I)

Line No.		New Jersey For the Year Ended December 31,2015	New York[1] For the Year Ended December 31,2015	West Virginia[2] For the Year Ended December 31,2015
1	Federal Depreciation Addback	$ (4,742,930)	$ (4,742,930)	$ -
2	State Depreciation Deduction	$ 10,065,293	$ 6,471,417	$ -

Note[1]: RECO is a member of a combined tax filing in the State of New York

Note[2]: RECO is a member of a combined tax filing in the State of West Virginia

Rockland Electric Company
Statement AT
State Tax Adjustments
For the Year Ended December 31, 2015 (Period I)

Line No.		New Jersey For the Year Ended December 31,2015	New York[1] For the Year Ended December 31,2015	West Virginia[2] For the Year Ended December 31,2015
1	State Income Taxes	$ 796,377	$ 796,377	$ 796,377

Note[1]: RECO is a member of a combined tax filing in the State of New York

Note[2]: RECO is a member of a combined tax filing in the State of West Virginia

Rockland Electric Company
Statement AU
Revenue Credits
For the Year Ended December 31, 2015 (Period I)

Period 1: Year Ended December 31, 2015

Acct. 4500

N/A

Acct. 4510

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Month Current Year	Month Prior Year
DEC-15	Rockland Electric Company	19999	SUSPENSE ACCOUNT FOR POSTING APPLICATIONS	$0.00	$0.00
		41070	ACCOMODATION WORK	$0.00	$0.00
		41076	OTHER REV	($21,696.83)	($20,989.92)
		41116	OTHER REV SERVICE FEE	($10,257.00)	$0.00
Grand Total				**($31,953.83)**	**($20,989.92)**

Acct 4520

N/A

Acct 4530

N/A

Acct 4540

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Month Current Year	Month Prior Year
DEC-15	Rockland Electric Company	19999	SUSPENSE ACCOUNT FOR POSTING APPLICATIONS	$0.00	$0.00
		41114	OTHER REV RENTAL PROPERTY	($380,692.49)	($291,353.94)
Grand Total				**($380,692.49)**	**($291,353.94)**

Acct 4550

N/A

Acct 4560

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year	Actual Balance Current Month Prior Year
DEC-15	Rockland Electric Company	19999	SUSPENSE ACCOUNT FOR POSTING APPLICATIONS	$0.00	$0.00
		41072	REACTIVE POWER CARRYING CHARGE	$0.00	$0.00
		41076	OTHER REV	$5,359,646.29	$4,008,127.13
		41096	OTHER REV LATE PAYMENT CHARGE	($152,450.74)	($138,217.01)
		41115	OTHER REV RETENTION OF PROP TAX INCENTIVE	$0.00	($244,111.03)
		41116	OTHER REV SERVICE FEE	($709.67)	($2,139.72)
		41119	OTHER REV SYS BENEFIT CHGE	$0.00	$46,800.76
		41122	OTHER REV TRANSMISSION	$6,608.14	$0.00
		41192	TBC TAX SECURITIZATION	$2,530,722.00	$2,460,927.66
Grand Total				**$7,743,816.02**	**$6,131,387.79**

Acct 4470

N/A

Rockland Electric Company
Statement AV
Rate of Return
For the Year Ended December 31, 2015 (Period I)

ROCKLAND ELECTRIC COMPANY

Consolidated Capitalization

Orange and Rockland Utilities, Inc. and Utility Subsidiaries

At December 31, 2015

	Amount	Ratio	Cost Rate	Weighted Cost
Long Term Debt				
ORU	$ 660,000,000			
Pike	3,200,000			
Total	663,200,000	51.93%	4.93%	2.56%
Common Equity				
Total	613,925,680	48.07%	10.70%	5.14%
Total Capitalization	$ 1,277,125,680	100.00%		7.70%

ORANGE AND ROCKLAND UTILITIES, INC. AND SUBSIDIARIES

WEIGHTED AVERAGE COST OF LONG TERM DEBT

ORU	Issue Date	Maturity Date	**Dec-15**
Debentures:			
Ser. B 2015, 4.69%, due 12/1/45	12/7/15	12/1/45	100,000,000
Ser. A 2015, 4.95%, due 2/15/45	6/18/15	7/1/45	120,000,000
E/F 6.50% due 12/01/27	12/15/97	12/1/27	80,000,000
Ser. B 2010, 5.50%, due 8/10/40	8/9/10	8/10/40	115,000,000
Ser. A 2006, 5.45%, due 10/1/16	10/4/06	10/1/16	75,000,000
Ser. A 2008, 6.15%, due 9/1/18	8/20/08	9/1/18	50,000,000
Ser. A 2009, 4.96%, due 12/1/19	12/8/09	12/1/19	60,000,000
Ser. B 2009, 6.00%, due 12/1/39	12/8/09	12/1/39	60,000,000
Sub Total			660,000,000
Pike			
First Mortgage Bonds:			
C 7.070% due 10/01/18			3,200,000
Total Pike			3,200,000
CONSOLIDATED TOTAL			663,200,000

Rockland Electric Company
Statement AW
Cost of Short-Term Debt
For the Year Ended December 31, 2015 (Period I)

Statement AW is not applicable. RECO does not have any debt on its books.

Rockland Electric Company
Statement AX
Other recent and pending rate changes
For the Year Ended December 31, 2015 (Period I)

Statement AX is not applicable. There are no recent or pending FERC rate changes for Rockland Electric Company.

Rockland Electric Company
Statement AY
Income and revenue tax rate data
For the Year Ended December 31, 2015 (Period 1)

Line No.		
1	Effective Tax Rate Reconciliation is as follows:	
2		
3	Federal income tax rate	35.00%
4	State income tax rate	9.00%
5	Federal Benefit of State Income Taxes	-3.15%
6	Sub-Total	40.85%
7	Gross-up Factor	1.6906
8	Total Income Tax Rate	69.06%

Note: Formula rate gross-up factor results from current Tariff Schedule 9 formula rate recovery structure; wherein, charges to customers must equal actual costs incurred. In order for charges to customers for income taxes to equal the income tax expense, the estimated income tax expense needs to be grossed-up.

Rockland Electric Company
Statement BA
Wholesale customer rate groups
For the Year Ended December 31, 2015 (Period I)

Tariff Schedule	Customer Rate Groups/Service Categories
Schedule 1A:	Scheduling, System Control and Dispatch Costs
Schedule 7:	Long-term firm and short-term firm point-to-point transmission service
Schedule 8:	Non-firm point-to-point transmission service
Attachment H-12:	Annual Transmission Rates for Network Integration Transmission Service

Rockland Electric Company
Statements BB
Allocation demand and capability data
For the Year Ended December 31, 2015 (Period I)

Upon FERC approval of a transmission revenue requirement and the RECO scheduling system control and dispatch ("SSC&D") rate, RECO will translate the transmission revenue requirement into service classification specific transmission rates. The RECO SSC&D rate will be added to the service classification specific per kWh rates. The derivation of the service classification specific retail transmission rates will be filed with the Board of Public Utilities for their approval for inclusion in RECO's retail customer tariff – B.P.U. No. 3 – Electricity.

Rockland Electric Company
Statements BC
Reliability data
For the Year Ended December 31, 2015 (Period I)

We will be seeking a waiver for Statement BC.

Rockland Electric Company
Statements BD
Allocation energy and supporting data
For the Year Ended December 31, 2015 (Period I)

See Statement BB.

Rockland Electric Company
Statements BE
Specific Assignment Data
For the Year Ended December 31, 2015 (Period I)

See Statement BB.

Rockland Electric Company
Statements BF
Exclusive-use commitments of major power supply facilities
For the Year Ended December 31, 2015 (Period I)

We will be seeking a waiver for Statement BF.

Rockland Electric Company
Statement BG
Revenue Data to Reflect Changed Rates
For the Year Ended December 31, 2015 (Period I)

The revenue to be collected is as shown on EXHIBIT RECO-2, Electric Transmission Revenue Requirement, which contains the calculations supporting the Company's requested transmission revenue requirement. Upon approval of the revenue requirement, retail rates will be filed with the Board of Public Utilities to collect this revenue requirement.

Rockland Electric Company
Statement BH
Revenue Data to Reflect Present Rates
For the Year Ended June 30, 2017 (Period II)

The current revenue requirement is shown on the Summary Page of EXHIBIT RECO-2, Electric Transmission Revenue Requirement. The current revenue requirement in present rates (in effect since 1994) is $11,785,928.

Rockland Electric Company
Statement BI
Fuel Cost Adjustment Factors
For the Year Ended December 31, 2015 (Period I)

Statement BI is not applicable.

Rockland Electric Company
Statements BJ-BK
Summary data tables
Electric utility department cost of service, total and as allocated
For the Year Ended December 31, 2015 (Period I)

We will be seeking a waiver for Statements BJ-BK.

Rockland Electric Company
Statement BL
Rate Design Information
For the Year Ended December 31, 2015 (Period I)

RECO's current rate design was approved in July 23, 2014 to collect the following revenue requirements. These revenue requirements were then translated into retail rates that were approved by the New Jersey Board of Public Utilities to all full service customers.

1. Transmission Owner Scheduling, System Control and Dispatch Service
   $0.2475/MWh

2. Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service
   $32.114/kW (Annual); $2.676/kW (Monthly); $0.6176/kW (Weekly);
   $0.1235/kW (Daily Peak); $0.0882/kW (Daily Off-Peak)

3. Non-Firm Point-To-Point Transmission Service
   $2.676/kW (Monthly); $0.6176/kW (Weekly); $0.1235/kW (Daily Peak);
   $0.0882/kW (Daily Off-Peak),
   $7.7/MWh (Hourly On Peak); $3.67/MWh (Hourly Off Peak)

4. Annual Transmission Rates – Network Integration Transmission Service
   $11,785,928 (Annual Transmission Revenue Requirement)
   $32,114/MW/yr (Network Integration Transmission Service)

Rockland Electric Company
Statement BM
Construction Program Statement
For the Year Ended December 31, 2015 (Period I)

Statement BM is not applicable because RECO is not seeking a return on Construction Work in Progress (CWIP).

Rockland Electric Company

Statement AA

Balance Sheet

For the Year Ended June 30, 2017 (Period II)

Balance Sheet

Thousands of Dollars

		Forecasted 2017 June
ASSETS		
Utility Plant		
V2170.00.000	V2170.00.000 - Utility plant, at original cost	369,671
V2190.00.000	V2190.00.000 - Accumulated depreciation	(89,853.4)
V6445.00.550	V6445.00.550 - Net plant (gross less depr)	279,817
V2180.00.000	V2180.00.000 - Utility construction in progress	5,199
V2200.00.000	**V2200.00.000 - Net utility plant & CWIP**	**285,016**
Current and Accrued Assets		
V2017.00.000	V2017.00.000 - Total ST investments	16,889
V2020.00.000	V2020.00.000 - Accounts receivable	18,969
V2030.00.000	V2030.00.000 - Allowance for doubtful accounts	(298)
V2095.00.000	V2095.00.000 - Accrued Unbilled Revenue	11,614
V2070.00.000	V2070.00.000 - Intercompany current assets	9,346
V2040.00.100	V2040.00.100 - Liquid fuel inventory	0
V2040.00.200	V2040.00.200 - Other materials and supplies	2,826
V2040.00.300	V2040.00.300 - Natural gas in storage	0
V2060.00.100	V2060.00.100 - Prepaid property taxes	7,775
V2060.00.200	V2060.00.200 - Other prepayments	219
V2090.00.000	V2090.00.000 - Other current assets	2,398
V2100.00.000	**V2100.00.000 - Total current assets**	**69,739**
Other Property and Investments		
V2390.00.125	V2390.00.125 - Net Non-utility Property	0
V2390.00.225	V2390.00.225 - Total Investments in Subs	232
V2390.00.250	V2390.00.250 - Other investments	0
V2390.00.000	**V2390.00.000 - Other property and investments**	**232**
Deferred Debits		
V2420.00.000	V2420.00.000 - Equity Investment	0
V2440.00.000	V2440.00.000 - Recoverable fuel charges deferred	0
V6445.00.565	V6445.00.565 - Other Deferred Debits Reporting Acct	836
V2470.00.000	V2470.00.000 - Regulatory assets	47,389
V6445.00.570	**V6445.00.570 - Other Non-Current Assets Reporting Acct**	**48,225**
V2490.00.000	**V2490.00.000 - Total assets**	**$403,211**

CAPITALIZATION AND LIABILITIES

Common Stockholders Equity		
V2830.00.000	V2830.00.000 - Common stock	$11,200
V2836.00.000	V2836.00.000 - Treasury stock	0
V2880.00.100	V2880.00.100 - Capital stock expense	0
V2850.00.000	V2850.00.000 - Retained earnings	249,628
V2880.00.200	V2880.00.200 - Other comprehensive income	0
V2890.00.000	V2890.00.000 - Common equity	260,828
V2820.00.000	V2820.00.000 - Preferred stock	0
V2895.00.000	**V2895.00.000 - Total equity**	**260,828**
Long Term Debt		
V2700.00.000	V2700.00.000 - Long term scheduled debt (less premium/(c	0
V6445.00.659	V6445.00.659 - Unamortized premium/(discount) on lt deb	0
V6445.00.660	**V6445.00.660 - Total long term debt**	**0**
Non Current Liabilities		
V2790.00.200	V2790.00.200 - Accumulated provision for injuries and dam	50
V2790.00.100	V2790.00.100 - Other non current liabilities	1,186
V2790.00.300	V2790.00.300 - Minority interest	0
V2790.00.000	**V2790.00.000 - Other non current liabilities & provisions,**	**1,236**
Current and Accrued Liabilities		
V2520.00.000	V2520.00.000 - Notes payable	0
V2660.97.000	V2660.97.000 - Long term debt due within one year	0
V2500.00.000	V2500.00.000 - Accounts payable & deferrals	9,908
V2540.00.000	V2540.00.000 - Intercompany accounts payable	2,704
V2590.00.100	V2590.00.100 - Customer deposits	5,891
V2530.00.000	V2530.00.000 - Income taxes payable	1,602
V2525.00.000	V2525.00.000 - Interest accrued	0
V2590.00.500	V2590.00.500 - Uncertain Income Taxes	0
V2590.00.400	V2590.00.400 - System Benefit Charge and Energy Efficency	0
V2590.00.600	V2590.00.600 - Accrued Wages	0
V2595.00.000	V2595.00.000 - Dividends declared	0
V2590.00.200	V2590.00.200 - Misc current and accrued liabilities	15,047
V6445.00.575	**V6445.00.575 - Total Current and Accrued Liabilities Repo**	**35,152**
Deferred Credits		
V6445.00.580	V6445.00.580 - Deferred Income Taxes Reporting Acct	103,250
V2785.00.515	V2785.00.515 - Accumulated deferred investment tax credi	325
V2785.00.520	V2785.00.520 - Interruptible sales credit	0
V2785.00.530	V2785.00.530 - Interest on customer deposits and misc def	142
V6445.00.665	V6445.00.665 - Other Deferred Credits Reporting Acct	890
V2785.00.500	V2785.00.500 - Regulatory liability	1,389
V6445.00.670	**V6445.00.670 - Deferred credits**	**105,995**
V2900.00.000	**V2900.00.000 - Total capitalization and liabilities**	**$403,211**

Rockland Electric Company
Statement AB
Income Statement
For the Year Ended June 30, 2017 (Period II)

Operating and Financial Income Statement

Rockland Electric Company
YTD

			Actuals	Forecasted	Forecasted
	YTD December 2016	**YTD June 2016**	**July - December 2016**	**January 2017 - June 2017**	**Twelve Months Ended 6/30/17**
OPERATING REVENUES					
Revenue from Sales of Electric, Gas & Steam	190,788,491.19	85,630,078.44	105,158,412.75	90,275,300.00	195,433,712.75
Other Operating Revenues	(6,800,927.63)	(3,474,283.87)	(3,326,643.76)	351,900.00	(2,974,743.76)
TOTAL - OPERATING REVENUES	183,987,563.56	82,155,794.57	101,831,768.99	90,627,200.00	192,458,968.99
OPERATION AND MAINTENANCE					
Operating Expenses					
Purchased Power	100,536,941.82	45,404,215.06	55,132,726.76	49,667,200.00	104,799,926.76
Other Production Expenses	0.00	0.00	0.00		0.00
Transmission	1,490,872.55	739,335.96	751,536.59	15,025,800.00	15,777,336.59
Distribution	5,424,458.06	2,643,621.09	2,780,836.97		2,780,836.97
Customer Accounts	5,289,825.62	2,487,626.11	2,802,199.51		2,802,199.51
Customer Service	10,002,154.69	4,420,431.66	5,581,723.03		5,581,723.03
Sales Promotion	2,191.85	601.95	1,589.90		1,589.90
Administrative and General	18,905,523.85	10,046,435.55	8,859,088.30	17,337,226.00	26,196,314.30
Total - Operating Expenses	141,651,968.44	65,742,267.38	75,909,701.06	82,030,226.00	157,939,927.06
Maintenance Expenses					
Transmission	166,485.26	71,990.11	94,495.15		94,495.15
Distribution	13,346,405.55	5,947,400.40	7,399,005.15		7,399,005.15
Adminstrative and General	403,190.95	72,657.57	330,533.38		330,533.38
Total - Maintenance Expenses	13,916,081.76	6,092,048.08	7,824,033.68	0.00	7,824,033.68
TOTAL - OPERATION AND MAINTENANCE	155,568,050.20	71,834,315.46	83,733,734.74	82,030,226.00	165,763,960.74
Depreciation Expense	8,888,120.87	4,354,426.79	4,533,694.08	4,767,200.00	9,300,894.08
Amort. & Depl. of Utility Plant	34,452.89	16,875.81	17,577.08		17,577.08
Taxes Other Than Income Taxes	1,819,105.82	1,099,078.61	720,027.21	1,237,500.00	1,957,527.21
Income Taxes -- Federal and Other	3,021,062.02	(28,392.06)	3,049,454.08	950,664.92	4,000,119.00
Provision for Deferred Income Taxes	27,645,786.85	8,653,062.87	18,992,723.98		18,992,723.98
Provision for Deferred Income Taxes -Cr.	(23,547,905.87)	(6,704,488.42)	(16,843,417.45)		(16,843,417.45)
Investment Tax Credit Adj. -- Net	(51,348.00)	(25,674.00)	(25,674.00)	(25,219.00)	(50,893.00)
Total Utility Operating Expenses	173,377,324.78	79,199,205.06	94,178,119.72	88,960,371.92	183,138,491.64
NET UTILITY OPERATING INCOME	10,610,238.78	2,956,589.51	7,653,649.27	1,666,828.08	9,320,477.35
OTHER INCOME AND DEDUCTIONS					
Other Income					
Nonutility Operating Income					
Interest and Dividend Income	127,556.36	56,623.98	70,932.38	107,438.52	178,370.90
Allowance for Other Funds Used During Construction	556,347.82	304,614.91	251,732.91	137,400.00	389,132.91
Total Other Income	683,904.18	361,238.89	322,665.29	244,838.52	567,503.81
Other Income Deductions					
Total Other Income Deductions	206,447.34	108,958.52	97,488.82	87,044.48	184,533.30
Taxes Applic. to Other Income and Deductions					
Taxes Other Than Income Taxes	18,470.10	9,114.30	9,355.80		9,355.80
Income Taxes -- Federal and Other	(854,384.94)	(105,264.35)	(749,120.59)		(749,120.59)
Provision for Deferred Inc. Taxes	134,030.46	27,415.35	106,615.11		106,615.11
Provision for Deferred Income Taxes Credit	(9,595.84)	(9,595.38)	(0.46)		(0.46)
Total Taxes on Other Income and Deduct.	(711,480.22)	(78,330.08)	(633,150.14)	0.00	(633,150.14)
NET OTHER INCOME AND DEDUCTIONS	1,188,937.06	330,610.45	858,326.61	157,794.05	1,016,120.66
INTEREST CHARGES					
Other Interest Expense	59,523.53	25,675.86	33,847.67	600.00	34,447.67
Allowance for Borrowed Funds Used During Construction	(272,738.44)	(149,702.94)	(123,035.50)	(83,700.00)	(206,735.50)
NET INTEREST CHARGES	(213,214.91)	(124,027.08)	(89,187.83)	(83,100.00)	(172,287.83)
NET INCOME	12,012,390.75	3,411,227.04	8,601,163.71	1,907,722.13	10,508,885.84
Preferred Stock Dividend Requirements	0.00	0.00	0.00		
NET INCOME APPLICABLE TO COMMON STOCK	12,012,390.75	3,411,227.04	8,601,163.71	1,907,722.13	10,508,885.84

Rockland Electric Company
Statement AC
Retained Earnings
For the Year Ended June 30, 2017 (Period II)

Statement of Change in Retained Earnings

	Forecasted Jun-17
Rockland Electric	
Beginning Retained Earnings	$248,263.6
Net Income	1,364.7
Dividend Paid to O&R	0.0
Ending Retained Earnings	249,628.3

Rockland Electric Company
Statement AD
Cost of Plant
For the Year Ended June 30, 2017 (Period II)
($000s)

	Forecasted 6/30/2017
Utility plant, at original cost	369,671
Accumulated depreciation	(89,853)
Net plant (gross less depr)	279,817
Utility construction in progress	5,199
Net utility plant & CWIP	285,016

Rockland Electric Company
Statement AE
Accumulated Depreciation
For the Year Ended June 30, 2017 (Period II)
($000s)

	Forecasted **6/30/2017**
Accumulated depreciation	(89,853)

Rockland Electric Company
Statement AF
Specified Deferred Credits
For the Year Ended June 30, 2017 (Period II)

Specified Deferred Credits

Period II: Year Ended June 30, 2017

Acct 255

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Month Current Year
JUN-16	Rockland Electric Company	23010	ACCUM DEFER INVEST TAX CREDIT	($375,611.80)
JUL-16	Rockland Electric Company	23010	ACCUM DEFER INVEST TAX CREDIT	($371,332.80)
AUG-16	Rockland Electric Company	23010	ACCUM DEFER INVEST TAX CREDIT	($367,053.80)
SEP-16	Rockland Electric Company	23010	ACCUM DEFER INVEST TAX CREDIT	($362,774.80)
OCT-16	Rockland Electric Company	23010	ACCUM DEFER INVEST TAX CREDIT	($358,495.80)
NOV-16	Rockland Electric Company	23010	ACCUM DEFER INVEST TAX CREDIT	($354,216.80)
DEC-16	Rockland Electric Company	23010	ACCUM DEFER INVEST TAX CREDIT	($349,937.80)
Jun 2017 (Estimated)				($360,635.30)

Average of Beginning & Ending Balance ($368,123.55)

Acct 2810

N/A

Acct 2820

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actuals June 2016	Actuals July 2016	Actuals August 2016	Actuals September 2016	Actuals October 2016	Actuals November 2016	Actuals December 2016	Forecasted June 2017
	Rockland Electric Company	12234	ACCUM DEFER FIT 282 CURRENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		19999	SUSPENSE ACCOUNT FOR POSTING APPLICATIONS	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		22503	DEFER FIT NONCURRENT	($6,185,101.29)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		22504	DEFER SIT NONCURRENT	($5,119.20)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		22515	ACCUMULATED DEFERRED FIT - 282 - NONCURRENT	($44,445,151.94)	($51,195,490.24)	($51,712,925.08)	($52,667,423.42)	($53,267,597.83)	($53,739,051.93)	($54,467,544.83)	($52,841,672.22)
		22518	ACCUMULATED DEFERRED SIT - 282 - NONCURRENT	($9,211,312.45)	($9,304,850.29)	($9,373,472.29)	($10,170,356.75)	($10,297,291.75)	($10,497,160.25)	($10,653,518.42)	($10,049,441.63)
		22551	DEFER FEDERAL INCOME TAX UNFUNDED	($11,796,948.60)	($11,796,948.60)	($11,796,948.60)	($11,796,948.60)	($11,796,948.60)	($11,796,948.60)	($11,796,948.60)	($11,796,948.60)
		22553	ACCUM DEFER FIT 282 UNFUNDED PLANT	($3,022,084.04)	($3,068,617.55)	($3,229,823.50)	($3,162,630.62)	($3,196,438.77)	($3,200,875.48)	($3,174,419.81)	($3,172,134.29)
		22556	ACCUM DEFER SIT 282 UNFUNDED PLANT	($1,316,634.00)	($1,316,634.00)	($1,355,264.12)	($1,381,759.48)	($1,384,814.10)	($1,326,996.79)	($1,323,589.15)	($1,348,176.27)
		22560	ACCUM DEFER FIT 283 GROSSUP	($469,034.77)	($469,034.77)	($469,034.77)	($469,034.77)	($469,034.77)	($469,034.77)	($469,034.77)	($469,034.77)
		22561	ACCUM DEFER SIT 190 GROSSUP	($1,299,996.00)	($1,299,996.00)	($1,299,996.00)	($1,299,996.00)	($1,299,996.00)	($1,299,996.00)	($1,299,996.00)	($1,299,996.00)
		22562	ACCUM DEFER SIT 283 GROSSUP	$399,719.00	$399,719.00	$399,719.00	$399,719.00	$399,719.00	$399,719.00	$399,719.00	$399,719.00
		23006	DEFER FIT LONG TERM	$3,216.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Grand Total				**($73,126,788.99)**	**($78,051,852.45)**	**($78,837,745.36)**	**($80,548,430.64)**	**($81,312,402.82)**	**($81,930,344.82)**	**($82,785,332.58)**	**($80,577,684.78)**

Average of Beginning & Ending Balance ($76,852,236.88)

Acct 2830

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actuals June 2016	Actuals July 2016	Actuals August 2016	Actuals September 2016	Actuals October 2016	Actuals November 2016	Actuals December 2016	Forecasted June 2017
	Rockland Electric Company	12235	ACCUM DEFER FIT 283 CURRENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		12238	ACCUM DEFER SIT 283 CURRENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		19999	SUSPENSE ACCOUNT FOR POSTING APPLICATIONS	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		21871	DEFER FIT CURRENT	($1,528,175.95)	$0.00	($1,528,175.95)	$0.00	$0.00	$0.00	$0.00	$0.00
		21885	UNCERTAIN FIT CURRENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		21886	UNCERTAIN SIT CURRENT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		22503	DEFER FIT NONCURRENT	($12,918,891.85)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		22504	DEFER SIT NONCURRENT	$1,310,083.86	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		22514	ACCUMULATED DEFERRED FIT - 190 - NONCURRENT	$363,825.64	$363,825.64	$363,825.64	$363,825.64	$363,825.64	$363,825.64	$363,825.64	$363,825.64
		22515	ACCUMULATED DEFERRED FIT - 282 - NONCURRENT	($101,552.00)	($101,552.00)	($101,552.00)	($101,552.00)	($101,552.00)	($101,552.00)	($101,552.00)	($101,552.00)
		22516	ACCUMULATED DEFERRED FIT - 283 - NONCURRENT	($5,199,529.38)	($19,284,831.42)	($16,096,674.20)	($17,233,456.44)	($17,099,861.66)	($17,219,807.20)	($16,856,277.76)	($17,298,484.78)
		22517	ACCUMULATED DEFERRED SIT - 190 - NONCURRENT	$185,189.69	$185,189.69	$185,189.69	$185,189.69	$185,189.69	$185,189.69	$185,189.69	$185,189.69
		22518	ACCUMULATED DEFERRED SIT - 282 - NONCURRENT	($0.13)	($0.13)	($0.13)	($0.13)	($0.13)	($0.13)	($0.13)	($0.13)
		22519	ACCUMULATED DEFERRED SIT - 283 - NONCURRENT	($1,852,519.84)	($4,683,941.74)	($4,214,873.26)	($4,103,267.23)	($4,065,516.74)	($4,099,410.29)	($3,996,686.09)	($4,193,949.23)
		22551	DEFER FEDERAL INCOME TAX UNFUNDED	($6,739,053.27)	($6,739,053.21)	($6,739,053.27)	($6,739,053.24)	($6,739,053.24)	($6,739,053.24)	($6,739,053.24)	($6,739,053.24)
		22555	ACCUM DEFER FIT 283 UNFUNDED NONPLANT	$249,977.20	$249,977.20	$249,977.20	$253,544.81	$253,544.81	$253,544.81	$253,544.81	$253,544.81
		22558	ACCUM DEFER SIT 283 UNFUNDED NONPLANT	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
		22560	ACCUM DEFER FIT 283 GROSSUP	($1,604,400.84)	($1,636,537.64)	($1,737,061.42)	($1,670,041.42)	($1,689,890.59)	($1,661,147.23)	($1,645,067.01)	($1,673,290.89)
		22562	ACCUM DEFER SIT 283 GROSSUP	$0.00	$0.00	($37,486.48)	($73,936.11)	($79,544.98)	($71,422.84)	($66,878.98)	($65,853.88)
		23006	DEFER FIT LONG TERM	$268,278.45	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		23015	DEFER SIT LONG TERM	($4,167,922.90)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Grand Total				**($31,734,691.31)**	**($31,646,923.60)**	**($29,655,884.17)**	**($29,118,746.42)**	**($28,972,859.19)**	**($29,089,832.78)**	**($28,602,955.06)**	**($29,269,623.99)**

Average of Beginning & Ending Balance ($30,502,157.65)

Rockland Electric Company
Statement AG
Specified Plant Accounts and Deferred Debits
For the Year Ended June 30, 2017 (Period II)

Specified Plant Accounts and deferred debits

Period 1: Year Ended June 30, 2017

Acct 1050, Plant Held for Future Use

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year	
JUN-16	Rockland Electric Company	14001	UTILITY PLANT	$2,262,977.36	
Jun 2017 (Estimated)	Rockland Electric Company	14001	UTILITY PLANT	$2,262,977.36	no forecasted change

Average of Beginning & Ending Balanc $ 2,262,977.36

Acct 1070, Construction Work-in-Progress

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year
Jun 2016	Rockland Electric Company	14021	CWIP	$24,432,756.82
Jul 2016	Rockland Electric Company	14021	CWIP	$25,618,893.95
Aug 2016	Rockland Electric Company	14021	CWIP	$9,526,056.73
Sep 2016	Rockland Electric Company	14021	CWIP	$9,944,466.24
Oct 2016	Rockland Electric Company	14021	CWIP	$10,695,078.25
Nov 2016	Rockland Electric Company	14021	CWIP	$11,598,675.66
Dec 2016	Rockland Electric Company	14021	CWIP	$6,959,218.52
Jan 2017 (estimated)	Rockland Electric Company	14021	CWIP	$5,840,822.39
Feb 2017 (estimated)	Rockland Electric Company	14021	CWIP	$6,321,222.39
Mar 2017 (Estimated)	Rockland Electric Company	14021	CWIP	$7,233,422.39
Apr 2017 (Estimated)	Rockland Electric Company	14021	CWIP	$8,286,822.39
May 2017 (Estimated)	Rockland Electric Company	14021	CWIP	$9,135,222.39
Jun 2017 (Estimated)	Rockland Electric Company	14021	CWIP	$5,199,022.39

13-Month Average $ 10,497,982.57

Acct 1201
N/A

Acct 1820
N/A

Acct 1900

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	June 30, 2016 Balance	December 31, 2016 Balance	June 30, 2017 Balance
JUN-16	Rockland Electric Company	12230	DEFER FIT CURRENT	$0.00		
		12231	DEFER SIT CURRENT	$0.00		
		12233	ACCUM DEFER FIT 190 CURRENT	$0.00		
		12236	ACCUM DEFER SIT 190 CURRENT	$0.00		
		21871	DEFER FIT CURRENT	$0.00		
		21872	DEFER SIT CURRENT	$0.00		
		22503	DEFER FIT NONCURRENT	$4,731,546.14	$0.00	
		22504	DEFER SIT NONCURRENT	($257,468.67)	$0.00	
		22513	DEFER TAX ASSET UNCERTAIN BENEFIT FEDERAL OFFSET	$247,161.43	$247,161.43	$247,161.43
		22514	ACCUMULATED DEFERRED FIT - 190 - NONCURRENT	$4,463,328.54	$9,050,234.24	$10,441,542.74
		22516	ACCUMULATED DEFERRED FIT - 283 - NONCURRENT	($18,840.00)	($18,840.00)	($18,840.00)
		22517	ACCUMULATED DEFERRED SIT - 190 - NONCURRENT	($409,437.97)	$80,819.88	$107,069.88
		22551	DEFER FEDERAL INCOME TAX UNFUNDED	($234,799.21)	($234,799.21)	($234,799.21)
		22554	ACCUM DEFER FIT 190 UNFUNDED NONPLANT	$330,944.10	$308,065.58	$308,065.58
		22557	ACCUM DEFER SIT 190 UNFUNDED NONPLANT		($4,621.32)	($4,621.32)
		22559	ACCUM DEFER FIT 190 GROSSUP	$228,555.63	$204,534.47	$204,534.47
		22560	ACCUM DEFER FIT 283 GROSSUP	$158,898.00	$158,898.00	$158,898.00
		22561	ACCUM DEFER SIT 190 GROSSUP		$4,153.09	$4,153.09
		23005	AUTO DEPOSIT REFUND ADJ DUE CUSTOMER	$0.00		$0.00
		23006	DEFER FIT LONG TERM	$126.65		$0.00
		23015	DEFER SIT LONG TERM	$817,000.00		$0.00
		23017	ACCUMULATED DEFERRED FIT OCI PENSION RELATED	($11,091.41)	($11,091.41)	($11,091.41)
		23018	ACCUMULATED DEFERRED SIT OCI PENSION RELATED	($3,128.35)	($3,128.35)	($3,128.35)
Grand Total				**$10,042,794.88**	**$9,781,386.40**	**$11,198,944.90**

Average of Beginning & Ending Balance $10,620,869.89

Rockland Electric Company
Statement AH
O&M Expenses
For the Year Ended June 30, 2017 (Period II)

FERC or Natural Account Description	FERC or Natural Account Number	YTD December 2016	YTD June 2016	Actuals July 2016 - December 2016	Forecasted January 2017 - June 2017	Forecasted Twelve Months Ended June 30, 2017
Power Production Expenses	200					
Hydraulic Power Generation Electric Operations	302		-	-		-
Operations	535		-	-		-
Operation Supplies And Expenses	5401		-	-		-
						-
Other Power Supply Expenses Electric	304	100,536,941.82	45,404,215.06	55,132,726.76	49,667,200.00	104,799,926.76
Purchased Power	5550	100,536,941.82	45,404,215.06	55,132,726.76	49,667,200.00	104,799,926.76
System Control And Load Dispatching Other Expenses	5560		-	-		-
Other Expenses	5570		-	-		-
Total - Operation		100,536,941.82	45,404,215.06	55,132,726.76	49,667,200.00	104,799,926.76
Total - Maintenance		-	-	-		-
Total Power Production Expenses		100,536,941.82	45,404,215.06	55,132,726.76	49,667,200.00	104,799,926.76
Transmission Expenses Electric Operations	210					
Operations	305	1,406,871.13	693,613.84	713,257.29		713,257.29
Operation Supervision And Engineering	5600	382,650.64	166,851.89	215,798.75		215,798.75
Load Dispatch Reliability	5611	-	-	-		-
Scheduling,System Control & Dispatching Services	5614	55,720.31	26,527.18	29,193.13		29,193.13
Lt Reliab Plann & Standards Devel Svcs	5618	36,688.30	7,408.38	29,279.92		29,279.92
Station Expenses	5620	219,926.55	81,264.57	138,661.98		138,661.98
Overhead Line Expenses	5630	86,637.13	51,734.08	34,903.05		34,903.05
Miscellaneous Transmission Expenses	5660	564,002.76	298,582.30	265,420.46		265,420.46
Rents	5670	61,245.44	61,245.44	-		-
				-		-
Maintenance	306	166,485.26	71,990.11	94,495.15		94,495.15
Maintenance Of Structures Transmission	5690	24.42	-	24.42		24.42
Maintenance Of Station Equipment Transmission	5700	6,265.78	5,965.78	300.00		300.00
Maintenance Of Overhead Lines Transmission	5710	154,037.94	66,024.33	88,013.61		88,013.61
Maintenance Of Underground Lines Transmission	5720	6,157.12	-	6,157.12		6,157.12
Total Transmission Expenses		1,573,356.39	765,603.95	807,752.44	-	807,752.44
Regional/Market Expenses Electric	220					
Operations	307	84,001.42	45,722.12	38,279.30		38,279.30
Market Facilitation, Monitoring And Compliance Services	5757	84,001.42	45,722.12	38,279.30		38,279.30
Total Regional / Market Expenses		84,001.42	45,722.12	38,279.30	-	38,279.30
Distribution Expenses Electric	230					
Operations	399	5,424,458.06	2,643,621.09	2,780,836.97		2,780,836.97
Operation Supervision And Engineering	5800	1,667,269.75	765,847.59	901,422.16		901,422.16
Load Dispatching	5810	5,906.28	2,953.14	2,953.14		2,953.14
Station Expenses	5820	262,471.71	125,312.13	137,159.58		137,159.58
Overhead Line Expenses	5830	234,452.12	108,303.33	126,148.79		126,148.79
Underground Line Expenses	5840	159,007.29	83,018.13	75,989.16		75,989.16
Street Lighting And Signal System Expenses	5850	-	-	-		-
Meter Expenses	5860	180,003.24	92,885.51	87,117.73		87,117.73
Customer Installations Expenses	5870	-	-	-		-
Miscellaneous Distribution Expenses	5880	2,910,494.07	1,460,447.66	1,450,046.41		1,450,046.41
Rents	5890	4,852.60	4,853.60	(1.00)		(1.00)
				-		-
Maintenance	400	13,346,405.55	5,947,400.40	7,399,005.15		7,399,005.15
Maintenance Of Structures Distribution	5910	-	-	-		-
Maintenance Of Station Equipment Distribution	5920	13,824.23	(1,260.63)	15,084.86		15,084.86
Maintenance Of Overhead Lines Distribution	5930	12,709,238.54	5,743,333.63	6,965,904.91		6,965,904.91
Maintenance Of Underground Lines Distribution	5940	327,994.85	139,277.78	188,717.07		188,717.07
Maintenance Of Line Transformers	5950	-	-	-		-
Maintenance Of Street Lighting And Signal Systems	5960	295,347.93	66,049.62	229,298.31		229,298.31
Maintenance Of Meters	5970	-	-	-		-
Total Distribution Expenses		18,770,863.61	8,591,021.49	10,179,842.12	-	10,179,842.12
Customer Accounts Expenses	79					

Customer Account Operation	288	5,289,825.62	2,487,626.11	2,802,199.51		2,802,199.51
Supervision	9010	-	-	-		-
Meter Reading Expenses	9020	915,518.33	453,272.93	462,245.40		462,245.40
Customer Records And Collection Expenses	9030	3,656,047.22	1,781,907.71	1,874,139.51		1,874,139.51
Uncollectible Accounts	9040	611,944.95	175,645.02	436,299.93		436,299.93
Miscellaneous Customer Accounts Expenses	9050	106,315.12	76,800.45	29,514.67		29,514.67
Customer Service And Informational Expenses	81					
Customer Service Operation	290	10,002,154.69	4,420,431.66	5,581,723.03		5,581,723.03
Customer Service And Informational Expenses (Non Major)	9060	-	-	-		-
Customer Assistance Expenses	9080	8,987,834.94	3,938,732.78	5,049,102.16		5,049,102.16
Informational And Instructional Advertising Expenses	9090	113,912.52	42,613.25	71,299.27		71,299.27
Miscellaneous Customer Service And Informational Expenses	9100	900,407.23	439,085.63	461,321.60		461,321.60
Sales Expenses	83					
Sales Operation	291	2,191.85	601.95	1,589.90		1,589.90
Supervision	9110	1,069.71	-	1,069.71		1,069.71
Demonstrating And Selling Expenses	9120	1,122.14	601.95	520.19		520.19
Advertising Expenses	9130	-	-	-		-
Miscellaneous Sales Expenses	9160	-	-	-		-
Sales Expenses	9170	-	-	-		-
		-				
Administrative And General Expenses	85					
Administrative And General Operation	293	18,905,523.85	10,046,435.55	8,859,088.30	32,363,026.00	41,222,114.30
Administrative And General Salaries	9200	3,879,721.16	2,100,272.01	1,779,449.15		1,779,449.15
Office Supplies And Expenses	9210	804,605.36	310,737.53	493,867.83		493,867.83
Administrative Expenses Transferred Credit	9220	3,259,368.27	1,542,993.76	1,716,374.51		1,716,374.51
Outside Services Employed	9230	376,404.09	88,195.16	288,208.93		288,208.93
Property Insurance	9240	89,423.09	46,530.30	42,892.79		42,892.79
Injuries And Damages	9250	396,161.56	193,909.19	202,252.37		202,252.37
Other Employee Benefits Expenses	9260	718,481.18	366,639.09	351,842.09		351,842.09
Health And Life Expenses	9261	2,169,407.03	1,084,065.99	1,085,341.04		1,085,341.04
Pension Expense	9262	4,575,282.81	2,778,434.82	1,796,847.99		1,796,847.99
Other Post Retirement Benefit Expense	9263	(776,296.06)	(411,869.39)	(364,426.67)		(364,426.67)
Regulatory Commission Expenses	9280	733,095.21	407,970.30	325,124.91		325,124.91
Duplicate Charges Credit	9290	(108,079.11)	(61,007.44)	(47,071.67)		(47,071.67)
General Advertising Expenses	9301	-	-	-		-
Miscellaneous General Expenses	9302	583,449.62	59,626.87	523,822.75		523,822.75
General Rents	9310	2,204,499.64	1,539,937.36	664,562.28		664,562.28
Transportation Expenses	9330	-	-	-		-
Administrative And General Maintenance	295	403,190.95	72,657.57	330,533.38		330,533.38
Maintenance Of General Plant	9350	403,190.95	72,657.57	330,533.38		330,533.38
Total - Operation		34,199,696.01	16,955,095.27	17,244,600.74	32,363,026.00	49,607,626.74
Total - Maintenance		403,190.95	72,657.57	330,533.38	-	330,533.38
Total Other Expenses		34,602,886.96	17,027,752.84	17,575,134.12	32,363,026.00	49,938,160.12
Grand Total		155,568,050.20	71,834,315.46	83,733,734.74	82,030,226.00	165,763,960.74

Rockland Electric Company
Statement AI
Wages and Salaries
For the Year Ended June 30, 2017 (Period II)

	Actuals	Forecasted	Forecasted
	July - December 2016	**January 2017 - June 2017**	**Twelve Months Ended 6/30/17**
Operation			
Production	-		-
Transmission	409,076.51	6,875,000.00	7,284,076.51
Distribution	1,389,355.94	in total	1,389,355.94
Customer Accounts	1,338,562.27		1,338,562.27
Customer Service & Informational	394,729.88		394,729.88
Administrative & General	647,403.32		647,403.32
Maintenance			
Production	-		-
Transmission	69,206.05		69,206.05
Distribution	1,133,883.39		1,133,883.39
Administrative & General	(23,842.28)		(23,842.28)
	5,358,375.08	6,875,000.00	12,233,375.08

Rockland Electric Company
Statement AJ
Depreciation and Amortization Expense
For the Year Ended June 30, 2017 (Period II)

			Actuals	Forecasted	Forecasted
	YTD December 2016	**YTD June 2016**	**July - December 2016**	**January 2017 - June 2017**	**Twelve Months Ended 6/30/17**
Depreciation Expense	8,888,120.87	4,354,426.79	4,533,694.08	4,767,200.00	9,300,894.08
Amort. & Depl. of Utility Plant	34,452.89	16,875.81	17,577.08		17,577.08
	8,922,573.76	4,371,302.60	4,551,271.16	4,767,200.00	9,318,471.16

Rockland Electric Company
Statement AK
Taxes Other than Income Taxes
For the Year Ended June 30, 2017 (Period II)

			Actuals	Forecasted	Forecasted
	YTD December 2016	**YTD June 2016**	**July - December 2016**	**January 2017 - June 2017**	**Twelve Months Ended 6/30/17**
Taxes Other Than Income Taxes	1,819,105.82	1,099,078.61	720,027.21	1,237,500.00	1,957,527.21
	1,819,105.82	1,099,078.61	720,027.21	1,237,500.00	1,957,527.21

Rockland Electric Company
Statement AL
Working Capital
For the Year Ended June 30, 2017 (Period II)
($000s)

	Forecasted **12 Month Average**	
Materials and Supplies	2,915	
Prepayments	1,690	
Net Cash Working Capital	10,602	LATEST LEAD LAG (Case ER16050428, 9+3 update)
		Exhibit P-3, Schedule 6
12 Months Average	**15,208**	

Rockland Electric Company
Statement AM
Construction Work-in-Progress
For the Year Ended June 30, 2017 (Period II)

Period 1: Year Ended June 30, 2017

Fiscal Period	Company Name	Natural Account Code	Natural Account Name	Actual Balance Current Month Current Year
Jun 2016	Rockland Electric Company	14021	CWIP	$24,432,756.82
Jul 2016	Rockland Electric Company	14021	CWIP	$25,618,893.95
Aug 2016	Rockland Electric Company	14021	CWIP	$9,526,056.73
Sep 2016	Rockland Electric Company	14021	CWIP	$9,944,466.24
Oct 2016	Rockland Electric Company	14021	CWIP	$10,695,078.25
Nov 2016	Rockland Electric Company	14021	CWIP	$11,598,675.66
Dec 2016	Rockland Electric Company	14021	CWIP	$6,959,218.52
Jan 2017 (estimated)	Rockland Electric Company	14021	CWIP	$5,840,822.39
Feb 2017 (estimated)	Rockland Electric Company	14021	CWIP	$6,321,222.39
Mar 2017 (Estimated)	Rockland Electric Company	14021	CWIP	$7,233,422.39
Apr 2017 (Estimated)	Rockland Electric Company	14021	CWIP	$8,286,822.39
May 2017 (Estimated)	Rockland Electric Company	14021	CWIP	$9,135,222.39
Jun 2017 (Estimated)	Rockland Electric Company	14021	CWIP	$5,199,022.39

13 Month Average **$ 10,497,982.57**

Rockland Electric Company
Statement AN
Notes Payable
For the Year Ended June 30, 2017 (Period II)

	Forecasted 6/30/2017
Notes Payable	$ -

Rockland Electric Company
Statements AO
Rate for allowance for funds used during construction
For the Year Ended June 30, 2017 (Period II)

We will be seeking a waiver for Statements AO.

Rockland Electric Company
Statement AP
Federal Income Tax Deduction - Interest
For the Year Ended June 30, 2017 (Period II)

Line No.				(Income)/Expense For Fiscal Year End 7/1/2016 to 6/30/2017
1	Interest deducted on federal tax return (estimated)			$ (180,552)
2	Interest expense consist of the following:			
		(1) interest on RECO's long-term debt	$ -	
		(2) other interest expense.	$ (180,552)	
			$ (180,552)	

Note: Consolidated Edison, Inc. files a consolidated federal tax return of which RECO is part of it.

Rockland Electric Company
Statement AQ
Federal Income Tax Deduction - Other than Interest
For the Year Ended June 30, 2017 (Period II)

Line No.		For Fiscal Year End 7/1/2016 to 6/30/2017	
1	Officer Compensation	$ -	**See Note**
2	Salaries and wages	$ -	**See Note**
3	Repairs and maintenance	$ -	**See Note**
4	Bad debts	$ -	**See Note**
5	Rents	$ -	**See Note**
6	Taxes and licenses	$ -	**See Note**
7	Depreciation	$ -	**See Note**
8	Pension, profit-sharing, etc., plans	$ -	**See Note**
9	Employee benefit programs	$ -	**See Note**
10	Other deductions as follows:	$ -	**See Note**

NOTE: Estimated amounts for the period July 1, 2016 through June 30, 2017 to be included in RECO's proforma federal tax return are not available.

Rockland Electric Company
Statement AR
Federal Tax Adjustments
For the Year Ended June 30, 2017 (Period II)

NOTE: Estimated amounts for the period July 1, 2016 through June 30, 2017 to be included in RECO's proforma federal tax return are not available.

Rockland Electric Company
Statement AS
Additional State Income Tax Deductions (Estimates)
For the Year Ended June 30, 2017 (Period II)

Line No.		New Jersey For Period 07-2016 to 06-2017	New York[1] For Period 07-2016 to 06-2017	West Virginia[2] For Period 07-2016 to 06-2017
1	Federal Depreciation Addback	$ -	$ -	$ -
2	State Depreciation Deduction	$ 11,950,410	$ 8,067,031	$ -

Note[1]: RECO is a member of a combined tax filing in the State of New York

Note[2]: RECO is a member of a combined tax filing in the State of West Virginia

Rockland Electric Company
Statement AT
State Tax Adjustments (Estimates)
For the Year Ended June 30, 2017 (Period II)

Line No.		New Jersey For Period 07-2016 to 06-2017	New York[1] For Period 07-2016 to 06-2017	West Virginia[2] For Period 07-2016 to 06-2017
1	State Income Taxes	$ 652,097	$ 652,097	$ 652,097

Note[1]: RECO is a member of a combined tax filing in the State of New York
Note[2]: RECO is a member of a combined tax filing in the State of West Virginia

Rockland Electric Company
Statement AU
Revenue Credits
For the Year Ended June 30, 2017 (Period II)

Acct. 4500
N/A

Acct. 4510

	Company Name	Natural Account Code	Natural Account Name	YTD December 2016	YTD June 2016	Actuals July 2016 - December 2016	Forecasted January 2017 - June 2017	Forecasted Twelve Months Ended June 30, 2017
	Rockland Electric Company	19999	SUSPENSE ACCOUNT FOR POSTING APPLICATIONS	$0.00	$0.00	$0.00		$0.00
		41070	ACCOMODATION WORK	$0.00	$0.00	$0.00		$0.00
		41076	OTHER REV	($19,953.70)	($13,508.14)	($6,445.56)	($6,445.56)	($12,891.12)
		41116	OTHER REV SERVICE FEE	($12,144.00)	($5,011.00)	($7,133.00)	($7,133.00)	($14,266.00)
Grand Total				($32,097.70)	($18,519.14)	($13,578.56)	($13,578.56)	($27,157.12)

Acct 4520
N/A

Acct 4530
N/A

Acct 4540

	Company Name	Natural Account Code	Natural Account Name	YTD December 2016	YTD June 2016	Actuals July 2016 - December 2016	Forecasted January 2017 - June 2017	Forecasted Twelve Months Ended June 30, 2017
	Rockland Electric Company	19999	SUSPENSE ACCOUNT FOR POSTING APPLICATIONS	$0.00	$0.00	$0.00		$0.00
		41114	OTHER REV RENTAL PROPERTY	($440,005.52)	($26,322.77)	($413,682.75)	$ (332,700.00)	($746,382.75)
Grand Total				($440,005.52)	($26,322.77)	($413,682.75)	($332,700.00)	($746,382.75)

Acct 4550
N/A

Acct 4560

	Company Name	Natural Account Code	Natural Account Name	YTD December 2016	YTD June 2016	Actuals July 2016 - December 2016	Forecasted January 2017 - June 2017	Forecasted Twelve Months Ended June 30, 2017
	Rockland Electric Company	19999	SUSPENSE ACCOUNT FOR POSTING APPLICATIONS	$0.00	$0.00	$0.00		$0.00
		41072	REACTIVE POWER CARRYING CHARGE	$0.00	$0.00	$0.00		$0.00
		41076	OTHER REV	$4,920,564.03	$2,410,743.95	$2,509,820.08	$ 2,509,820	$5,019,640.16
		41096	OTHER REV LATE PAYMENT CHARGE	($132,365.37)	($58,908.79)	($73,456.58)	$ (68,400)	($141,856.58)
		41115	OTHER REV RETENTION OF PROP TAX INCENTIVE	$0.00	$0.00	$0.00		$0.00
		41116	OTHER REV SERVICE FEE	($359.78)	$0.00	($359.78)	$ (5,400)	($5,759.78)
		41119	OTHER REV SYS BENEFIT CHGE	$0.00	$0.00	$0.00		$0.00
		41122	OTHER REV TRANSMISSION	$0.00	$0.00	$0.00		$0.00
		41192	TBC TAX SECURITIZATION	$2,490,849.97	$1,172,948.62	$1,317,901.35	$ 1,317,901	$2,635,802.70
Grand Total				$7,278,688.85	$3,524,783.78	$3,753,905.07	$3,753,921.43	$7,507,826.50

Acct 4470
N/A

Rockland Electric Company
Statement AV
Rate of Return
For the Year Ended June 30, 2017 (Period II)

ROCKLAND ELECTRIC COMPANY

Consolidated Capitalization

Orange and Rockland Utilities, Inc. and Utility Subsidiaries

At June 30, 2017

	Amount	Ratio	Cost Rate	Weighted Cost
Long Term Debt				
ORU	$ 660,000,000			
Pike	0			
Total	660,000,000	51.81%	4.93%	2.55%
Common Equity				
Total	613,925,680	48.19%	10.70%	5.16%
Total Capitalization	$ 1,273,925,680	100.00%		7.71%

ORANGE AND ROCKLAND UTILITIES, INC. AND SUBSIDIARIES

WEIGHTED AVERAGE COST OF LONG TERM DEBT

ORU	Issue Date	Maturity Date	**Jun-17**
Debentures:			
Ser. B 2015, 4.69%, due 12/1/45	12/7/15	12/1/45	100,000,000
Ser. A 2015, 4.95%, due 7/1/45	6/18/15	7/1/45	120,000,000
Series E/F 6.50% due 12/01/27	12/15/97	12/1/27	80,000,000
Ser. B 2010, 5.50%, due 8/10/40	8/9/10	8/10/40	115,000,000
Ser. A 2006, 5.45%, due 10/1/16	10/4/06	10/1/16	-
Ser. A 2008, 6.15%, due 9/1/18	8/20/08	9/1/18	50,000,000
Ser. A 2009, 4.96%, due 12/1/19	12/8/09	12/1/19	60,000,000
Ser. B 2009, 6.00%, due 12/1/39	12/8/09	12/1/39	60,000,000
Ser. A 2016, 3.88%, due 12/1/46	12/14/16	12/1/46	75,000,000
Sub Total			660,000,000

Pike	
First Mortgage Bonds:	
C 7.070% due 10/01/18	-
Total Pike	-
CONSOLIDATED TOTAL	660,000,000

Rockland Electric Company
Statement AW
Cost of Short-Term Debt
For the Year Ended June 30, 2017 (Period II)

Statement AW is not applicable. RECO does not have expect to have any debt on its books at June 30, 2017.

Rockland Electric Company
Statement AX
Other recent and pending rate changes
For the Year Ended June 30, 2017 (Period II)

Statement AX is not applicable.

Rockland Electric Company
Statement AY
Income and revenue tax rate data
For the Twelve Months Ended June 30, 2017 (Period 2)

Line No.		
1	Effective Tax Rate Reconciliation is as follows:	
2		
3	Federal income tax rate	35.00%
4	State income tax rate	9.00%
5	Federal Benefit of State Income Taxes	-3.15%
6	Sub-Total	40.85%
7	Gross-up Factor	1.6906
8	Total Income Tax Rate	69.06%

Note: Formula rate gross-up factor results from current Tariff Schedule 9 formula rate recovery structure; wherein, charges to customers must equal actual costs incurred. In order for charges to customers for income taxes to equal the income tax expense, the estimated income tax expense needs to be grossed-up.

Rockland Electric Company
Statement BA
Wholesale customer rate groups
For the Year Ended June 30, 2017 (Period II)

Tariff Schedule	Customer Rate Groups/Service Categories
Schedule 1A:	Scheduling, System Control and Dispatch Costs
Schedule 7:	Long-term firm and short-term firm point-to-point transmission service
Schedule 8:	Non-firm point-to-point transmission service
Attachment H-12:	Annual Transmission Rates for Network Integration Transmission Service

Rockland Electric Company
Statements BB
Allocation demand and capability data
For the Year Ended June 30, 2017 (Period II)

Upon FERC approval of a transmission revenue requirement and the RECO scheduling system control and dispatch (“SSC&D”) rate, RECO will translate the transmission revenue requirement into service classification specific transmission rates. The RECO SSC&D rate will be added to the service classification specific per kWh rates. The derivation of the service classification specific retail transmission rates will be filed with the Board of Public Utilities for their approval for inclusion in RECO’s retail customer tariff – B.P.U. No. 3 – Electricity.

Rockland Electric Company
Statements BC
Reliability data
For the Year Ended June 30, 2017 (Period II)

We will be seeking a waiver for Statement BC.

Rockland Electric Company
Statements BD
Allocation energy and supporting data
For the Year Ended June 30, 2017 (Period II)

See Statement BB.

Rockland Electric Company
Statements BE
Specific Assignment Data
For the Year Ended June 30, 2017 (Period II)

See Statement BB.

Rockland Electric Company
Statements BF
Exclusive-use commitments of major power supply facilities
For the Year Ended June 30, 2017 (Period II)

We will be seeking a waiver for Statement BF.

Rockland Electric Company
Statement BG
Revenue Data to Reflect Changed Rates
For the Year Ended June 30, 2017 (Period II)

The revenue to be collected is as shown on EXHIBIT RECO-2, Electric Transmission Revenue Requirement, which contains the calculations supporting the Company's requested transmission revenue requirement. Upon approval of the revenue requirement, retail rates will be filed with the Board of Public Utilities to collect this revenue requirement.

Rockland Electric Company
Statement BH
Revenue Data to Reflect Present Rates
For the Year Ended June 30, 2017 (Period II)

The current revenue requirement is shown on the Summary Page of EXHIBIT RECO-2, Electric Transmission Revenue Requirement. The current revenue requirement in present rates (in effect since 1994) is $11,785,928.

Rockland Electric Company
Statement BI
Fuel Cost Adjustment Factors
For the Year Ended June 30, 2017 (Period II)

Statement BI is not applicable.

Rockland Electric Company
Statements BJ-BK
Summary data tables
Electric utility department cost of service, total and as allocated
For the Year Ended June 30, 2017 (Period II)

We will be seeking a waiver for Statements BJ-BK.

Rockland Electric Company
Statement BL
Rate Design Information
For the Year Ended June 30, 2017 (Period II)

RECO's current rate design was approved in July 23, 2014 to collect the following revenue requirements. These revenue requirements were then translated into retail rates that were approved by the New Jersey Board of Public Utilities to all full service customers.

1. Transmission Owner Scheduling, System Control and Dispatch Service
   $0.2475/MWh

2. Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service
   $32.114/kW (Annual); $2.676/kW (Monthly); $0.6176/kW (Weekly);
   $0.1235/kW (Daily Peak); $0.0882/kW (Daily Off-Peak)

3. Non-Firm Point-To-Point Transmission Service
   $2.676/kW (Monthly); $0.6176/kW (Weekly); $0.1235/kW (Daily Peak);
   $0.0882/kW (Daily Off-Peak),
   $7.7/MWh (Hourly On Peak); $3.67/MWh (Hourly Off Peak)

4. Annual Transmission Rates – Network Integration Transmission Service
   $11,785,928 (Annual Transmission Revenue Requirement)
   $32,114/MW/yr (Network Integration Transmission Service)

Rockland Electric Company
Statement BM
Construction Program Statement
For the Year Ended June 30, 2017 (Period II)

Statement BM is not applicable because RECO is not seeking a return on Construction Work in Progress (CWIP).