August 5, 2016

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: Tariff Revisions to Attachment F of the ISO New England Open Access Transmission Tariff to Comply with Normalization Requirements

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d (2006), and part 35 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, 18 C.F.R. § 35.13 (2016), the Participating Transmission Owners Administrative Committee ("PTO AC"), on behalf of the Participating Transmission Owners ("PTOs") in New England,[1] hereby submits for filing revisions to Attachment F to Section II of the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("ISO-NE OATT").[2]

The enclosed revisions modify the calculation of transmission-related Accumulated Deferred Income Taxes ("ADIT") related to accelerated depreciation in the Attachment F

[1] Pursuant to Section 3.04 (b) of the Transmission Operating Agreement ("TOA"), the PTO AC makes this filing on behalf of the PTOs to jointly sponsor modifications to certain terms, conditions and rates in the ISO-NE Tariff. The PTOs' rights to make such modifications are held and exercised by the PTOs in accordance with the TOA, prior Commission Orders, and/or applicable case law. The PTOs include: Emera Maine f/k/a Bangor Hydro Electric Company; Town of Braintree Electric Light Department; NSTAR Electric Company; Chicopee Electric Light Department; Central Maine Power Company; Maine Electric Power Company; Connecticut Municipal Electric Energy Cooperative; Connecticut Transmission Municipal Electric Energy Cooperative; The City of Holyoke Gas and Electric Department; New Hampshire Transmission, LLC; Green Mountain Power Corporation; Massachusetts Municipal Wholesale Electric Company; Middleborough Gas and Electric Department; Town of Hudson Light and Power Department; New England Power Company d/b/a National Grid; New Hampshire Electric Cooperative, Inc.; Eversource Energy Service Company, as agent for The Connecticut Light and Power Company; Western Massachusetts Electric Company; and Public Service Company of New Hampshire; Taunton Municipal Lighting Plant; Town of Norwood Municipal Light Department; Town of Reading Municipal Light Department; Town of Wallingford (CT) Electric Division; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Electric Cooperative, Inc.; Vermont Electric Power Company, Inc.; Vermont Transco, LLC; Vermont Public Power Supply Authority; and Shrewsbury Electric and Cable Operations.

The PTOs, and not ISO-NE, share the Federal Power Act ("FPA") section 205 rights over Attachment F of the ISO-NE OATT. This filing is being submitted through the eTariff system by ISO-NE on behalf of the PTO AC in ISO-NE's capacity as administrator of the ISO-NE Tariff in the eTariff system.

[2] Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO-NE Transmission, Markets and Services Tariff, the Second Restated New England Power Pool Agreement, or the Participants Agreement by and among ISO-NE, the New England Power Pool, and the Individual Participants.

formula rate for Regional Network Service ("RNS") to incorporate the proration calculation of the Internal Revenue Service's ("IRS") regulations, consistent with guidance recently provided by the IRS. The revisions are intended to maintain compliance with the IRS's normalization rules and to thereby ensure the continued ability of each PTO to claim accelerated depreciation.[3] The PTO AC respectfully requests that the Commission grant waiver of its 60-day prior notice requirement to allow these revisions to Attachment F to become effective for the 2016/2017 rate year beginning as of June 1, 2016.[4]

I. DESCRIPTION OF FILING

A. Attachment F Background

Attachment F of the ISO-NE OATT provides the formula rate for the calculation of the Annual Transmission Revenue Requirement ("ATRR") for RNS, which is the basis for the rates for transmission service provided by ISO-NE over the Pool Transmission Facilities ("PTF") owned by the PTOs.[5] Each year on or before July 31, the PTOs collectively submit to the Commission an informational filing that details the updated Attachment F ATRR and the resulting derivation of the RNS rate that will be in effect from June 1 of that year through May 31 of the following year.[6] The PTOs also recover their cost of service not recovered under Attachment F through formulae set forth in individual attachments under Schedule 21 to the ISO-NE OATT addressing Local Network Service ("LNS").

The ATRR for RNS is the sum of three core components:[7] (i) a revenue requirement that is based on the aggregate of the PTOs' costs for PTF in service, drawn from their most recently-filed FERC Form 1 reports or a comparable source;[8] (ii) a projection of the revenue requirement associated with the aggregate of the PTOs' estimated PTF additions to be placed in service in the coming year, which is developed by multiplying the estimated PTF by a carrying charge that

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[3] A number of the PTOs are exempt from federal income tax and thus do not accrue ADIT balances. The enclosed revisions would have no effect on the ATRRs of such PTOs.

[4] *See* section II.B, *infra*.

[5] Attachment F is currently the subject of a Commission proceeding in Docket No. EL16-19-000. On December 28, 2015, the Commission instituted the proceeding under section 206 of the FPA into the RNS and LNS formula rates on two general grounds. *ISO New England Inc. Participating Transmission Owners Administrative Committee, et al.*, 153 FERC ¶ 61,343 (2015). The Commission found that the ISO-NE OATT lacks adequate transparency and challenge procedures with regard to the formula rates for the PTOs. In addition, and separate from the aforementioned concern, the Commission found that the PTOs' current RNS and LNS formula rates appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. The Commission stated that the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates. The parties to Docket No. EL16-19-000 presently are engaged in settlement discussions. It is the intent of the PTOs that upon Commission acceptance of this filing, the revisions proposed herein would be reflected among any modifications to the Attachment F formula rate that result from the proceeding in Docket No. EL16-19-000.

[6] The PTO AC filed the most recent annual update on July 29, 2016, in Docket Nos. RT04-2-000, *et al.*, for rates to be effective from June 1, 2016, to May 31, 2017.

[7] *See* ISO-NE OATT, Schedule 9, § 6.

[8] *See* ISO-NE OATT, Attachment F.

approximates representative levels of costs and return associated with the estimated PTF;[9] and (iii) a true-up component, representing the difference between the estimated ATRR for the prior rate year (including the projected revenue requirement for facilities to be placed in service) and the ATRR calculated with cost data for the most recent calendar year.[10] The true-up amount, including interest calculated pursuant to 18 C.F.R. § 35.19a, is added to or subtracted from the next year's ATRR.

The Attachment F formula rate uses end-of-year transmission ADIT balances, of which a significant portion represents deferred tax liabilities related to accelerated depreciation.[11] ADIT balances are included in the revenue requirement for in-service transmission facilities (the first component discussed above) and, through the carrying charge, in the projected revenue requirement for facilities expected to be placed in service in the coming rate year (the second component). The ADIT balances act as a reduction to rate base.[12]

B. The IRS's Proration Calculation for ADIT Balances

To be eligible to claim accelerated depreciation, the PTOs must maintain compliance with the normalization requirements of the Internal Revenue Code.[13] The IRS's normalization rules contain a precise methodology – the proration calculation – to be used when projected ADIT balances are included in a forward-looking formula rate. Section 1.167(*l*)-1(h)(6)(ii) of the IRS's regulations requires that, if a utility uses a future period (projected test year) to determine depreciation, "the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period."[14] The pro rata amount of any increase during the future period is determined by multiplying the increase by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future period.[15]

In several recent Private Letter Rulings ("PLRs"), the IRS has clarified the applicability of these rules to a public utility that uses a formula rate with a projected revenue requirement and a true-up. For example, in PLR 201541010, attached hereto as Attachment 4, the IRS concluded that a public utility that used projected data to populate a forward-looking formula rate was using a "future period," and that the utility must therefore use the proration calculation for projections of ADIT balances included in its rates.[16] In addition, the IRS concluded that the fact that the

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[9] *See* ISO-NE OATT, Attachment F, Appendix C.

[10] *Id*.

[11] *See* Attachment F, section II.A.1.e.

[12] *See* Attachment F, section II.A.1.

[13] 26 U.S.C. § 168(f)(2) (accelerated depreciation does not apply to public utility property if the taxpayer does not use a normalization method of accounting).

[14] 26 CFR § 1.167(l)-1(h)(6)(ii) (2015).

[15] *Id*.

[16] PLR 201541010 at 6-7. *See also* PLR 201531010 (April 14, 2015).

utility's formula rate incorporates a true-up adjustment does not mean that the utility is basing its rates upon a historical test year.[17]

Relevant here, the IRS also concluded that, while the utility in question had not complied with the normalization requirements due to its failure to use the proration calculation, the utility would not be sanctioned with a denial of accelerated depreciation.[18] The IRS found that the utility had acted in good faith, had attempted to comply with the normalization rules, and had made an effort to incorporate the proration calculation in its next rate change. The IRS also cautioned: "Where nonconforming rates cannot be adjusted or corrected to conform to the requirements of this ruling due to the operation of state or federal regulatory law, then such correction must be made in the next regulatory filing or proceeding in which Taxpayer's rates are considered."[19] The PTOs are making this filing and the necessary corrections "in the next regulatory filing or proceeding in which Taxpayer's rates are considered."

C. Description of the Proposed Revisions to Attachment F

As the Commission has acknowledged, the IRS's PLRs on the ADIT proration calculation represent guidance as to how the IRS interprets its regulations.[20] After studying the applicability of the PLR guidance to the Attachment F formula rate, the PTOs diligently collaborated to develop the appropriate revisions in order to ensure their continued compliance with the IRS's normalization rules. The PTOs seek to make the revisions effective "in the next regulatory filing," i.e., the Attachment F annual update effective June 1, 2016.

As indicated earlier, the Attachment F formula rate currently applies a carrying charge factor to estimated plant additions in order to approximate the expected return and costs associated with the additions during the future period. This approach is used to approximate ADIT for the estimated PTF additions as well.[21] Because Attachment F uses a "future test period," the PTOs must revise the formula to reflect the IRS's guidance. However, the proposed revisions will apply *only* to the forecasted Attachment F ATRR; the calculation of ADIT in the true-up calculation under Attachment F will continue to use actual data from the FERC Form 1.

In the enclosed revisions, the calculation of the ATRR is modified in Appendix C to Attachment F in order to, first, eliminate the existing noncompliant ADIT calculation, and second, incorporate a separate, compliant ADIT calculation. The first revision to Appendix C "cancels out" the existing calculation of ADIT in the forecasted ATRR. The revision adds a new definition of "Adjusted Carrying Charge Factor," which removes ADIT from the Carrying Charge Factor. Second, the Appendix C formula is revised to include a new definition of Forecasted ADIT, or "FADIT," that requires the projected change in ADIT related to accelerated

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[17] *Id*. at 7 ("The addition of the true up increases the ultimate accuracy of the rates but does not convert a future test period into a historical test period as those terms are used in the normalization regulations.").

[18] *Id*. at 10-11.

[19] *Id*. at 10.

[20] *Midcontinent Independent System Operator, Inc.*, 153 FERC ¶ 61,371 at P 40 (2015).

[21] *See* Attachment F, Appendix C, § 1.vi (defining the components of the Carrying Charge Factor, including Attachment F § II.A.1.e (transmission ADIT)).

depreciation and associated with PTF transmission plant to be calculated in accordance with IRS regulation Section 1.167(l)-1(h)(6). After cancelling out ADIT from the Carrying Charge Factor as described above, the impacts of FADIT will be calculated as a separate step. FADIT is multiplied by the Cost of Capital, which is already defined in Attachment F,[22] and the resulting value is deducted from the ATRR. The worksheets included in Attachment 3 demonstrate the application of the proration calculation over the rate period.[23]

D. The Proposed Revisions Are Just and Reasonable

Acceptance of the enclosed filing is consistent with Commission precedent. The Commission has previously recognized the importance of compliance with the IRS's normalization rules in order to allow a regulated entity to use accelerated depreciation.[24] With regard to the proration calculation in particular, the Commission has accepted recent formula rate revisions to incorporate the required calculation over the past year as awareness of the PLRs has grown.[25]

Like these formula rate modifications accepted by the Commission for other regions, the impact of incorporating the proration calculation into the Attachment F formula will likely cause an initial rate increase in the forecasted ATRR. However, customers ultimately will not pay higher charges because these prorated amounts will be trued-up to actual costs in the following year using actual ADIT data from the FERC Form 1. Thus, to the extent the forecasted ATRR is increased in a particular year due to the ADIT proration calculation, customers will be returned any excess amounts, with interest, as part of the true-up calculation in the following year. The Attachment F changes simply result in a timing difference which is necessary to comply with IRS regulations as recently clarified.

On the other hand, if the PTOs were to lose their ability to claim accelerated depreciation due to a potential IRS finding of noncompliance with the normalization rules, this could result in

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[22] The PTOs propose to include the definition of "Cost of Capital" from Attachment F Section II.A.2 for purposes of the calculation.

[23] As noted above, the PTOs recover their cost of service not recovered under Attachment F through formulae set forth in individual attachments to the ISO-NE OATT addressing LNS, designated as Schedule 21. Central Maine Power Company and The United Illuminating Company have determined that the formula rate projections provided for in their Schedule 21 LNS rates need to be amended in order to reflect the IRS proration rules, and intend to make separate filings to amend their Schedule 21 rates accordingly. The other PTOs have determined that the formula rate projections provided for in their Schedule 21 LNS rates are sufficiently flexible to accommodate the IRS proration rules without any changes to the language of the rate schedule, and therefore do not intend to make such filings.

[24] *See Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 170 (2002) (approving elimination of ADIT balance in conjunction with asset sale and explaining "[t]he Commission believes that the ADIT balance must be eliminated to comply with the IRS's normalization rules and to permit the pipeline to use accelerated depreciation. As the Commission stated in [*Koch Gateway Pipeline Co*., 74 FERC ¶ 61,088 at 61,276 (1996)], it is reluctant to take an action which would endanger a pipeline's right to favorable tax treatment through the use of normalization (i.e. deferring taxes) in the future.").

[25] *See MidAmerican Energy Co*., unpublished letter order, Docket No. ER16-16-000 (Dec. 30, 2015); *Midcontinent Independent System Operator, Inc.*, 153 FERC ¶ 61,371 (2015) (accepting ADIT revisions to the formula rates of Minnesota Power (and its subsidiary Superior Water, L&P), Montana-Dakota Utilities Co., Northern Indiana Public Service Company, Otter Tail Power Company, and Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana)).

significant rate increases. If the PTOs cannot claim accelerated depreciation, they would have to pay back deferred taxes and not have the benefit of accelerated depreciation going forward, which would result in less ADIT and higher rate base.

The effect of the proration calculation on the forecasted ATRR will depend from year to year on the level of planned investment by the PTOs. For the rate year beginning June 1, 2016, applying the proration calculation will cause the total RNS rate to increase by approximately $0.56/kW-year, from $103.30/kW-year to $103.86/kW-year. As explained above, however, there will be no actual rate increase to customers over time because, where the revenue requirement increases in any particular year due to the ADIT proration calculation, customers will be returned any excess amounts, with interest, as part of the true-up calculation in the following year. As Attachment 3 to this filing, the PTO AC includes workpapers showing the impact of the proration calculation on the ATRR for the rate year starting June 1, 2016. The impact of including the proration calculation in the individual ATRRs of certain affected PTOs are summarized in the table below:

PTO	**Total ATRR without ADIT proration**	**Total ATRR with ADIT proration**	**Difference**
Central Maine Power Company	$244,488,407	$244,862,074	$373,667
Emera Maine	$52,294,541	$51,913,700	($380,841)
Eversource Energy Service Company[26]	$764,749,214	$768,857,928	$4,108,714
Fitchburg Gas & Electric Light Company	$1,210,464	$1,227,218	$16,754
Maine Electric Power Company	$4,065,741	$4,064,799	($942)
New England Power Company	$414,211,208	$417,898,117	$3,686,909
New Hampshire Transmission	$5,463,968	$5,511,619	$47,651
NSTAR Electric Company	$242,163,440	$245,254,249	$3,090,809
The United Illuminating Company	$148,121,871	$148,542,822	$420,951
VT Transco	$145,948,098	$145,816,223	($131,875)

[26] Representing certain of its operating company affiliates (The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire).

II. Additional Requirements of Part 35 of the Commission's Regulations

A. Contents of Filing

This filing consists of the following:

- This transmittal letter;
- Attachment 1a: Clean version of the revised Appendix C to Attachment F;
- Attachment 1b: Redlined version of the revised Appendix C to Attachment F;
- Attachment 2: June 27, 2016 notice provided to stakeholders in New England;
- Attachment 3: Supporting workpapers;
- Attachment 4: IRS Private Letter Ruling 201541010;
- Attachment 5: List of Participating Transmission Owners sponsoring this filing; and
- Attachment 6: Service List of state regulators and other interested parties.

B. Requests for Waivers

1. Requested Effective Date of June 1, 2016

The PTO AC respectfully requests waiver of the Commission's prior notice requirements to permit an effective date of June 1, 2016, for the enclosed revisions. Good cause exists to grant the waiver. First, granting a June 1, 2016 effective date will allow the PTOs to incorporate the ADIT proration calculation into their rates as part of their current annual update, which is arguably the "next proceeding in which Taxpayer's rates are considered," consistent with the guidance of the IRS in PLR 201541010 for when it would consider not seeking sanctions.

Second, the waiver is consistent with Commission policy. The Commission has explained that "waiver of notice generally will be appropriate when an uncontested filing has no rate impact."[27] As discussed above, the ADIT proration calculation will not ultimately result in higher charges to customers, as the true-up calculation will continue to be based on FERC Form 1 balances and any excess amounts collected from customers due to the ADIT proration calculation will be refunded, with interest.

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[27] *Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139 at 61,974 (1993) (discussing *Central Hudson Gas & Electric Corp. et al.*, 60 FERC ¶ 61,106, *reh'g denied*, 61 FERC ¶ 61,089 (1992)).

In addition, the PTOs provided advance notice to stakeholders on June 27, 2016, of their intent to submit the instant filing to ensure compliance with the ADIT proration calculation. The PTO AC includes a copy of the notice as Attachment 2 to this filing. The PTOs also provided additional workpapers showing the ADIT proration calculation with their posting of the draft annual update on June 15, 2016 for stakeholder review.

2. Other Requirements of 18 C.F.R. § 35.13

Included as Attachment 3 to this filing are supporting workpapers showing the calculation of the proration adjustment to the PTOs' ADIT balances and the resulting impact on the revenue requirement. To the extent necessary, the PTO AC respectfully requests waiver of any requirements of 18 C.F.R. § 35.13 that would require the inclusion of additional cost of service statements to support the proposed revisions to Attachment F. Good cause exists for such waiver. The rate revisions are required by IRS regulations, and the workpapers provided in Attachment 3 support the reasonableness of the calculations pursuant to those regulations. Additional detailed statements of the applicant's cost of service are not needed where the proposed rates are formulary and will be based on actual costs as reflected in the applicant's audited books and records. Further, such waiver would be consistent with Commission precedent for formula rates of this nature.[28]

C. Communications

Communications regarding this filing should be addressed to the individuals from the sponsoring PTOs listed in Attachment 5.

D. The Names and Addresses of Persons to Whom a Copy of the Rate Change Has Been Posted – Section 35.13(b)(3)

A copy of this submission is being sent to state regulators in New England, the New England Conference of Public Utility Commissioners, ISO-NE, NEPOOL and the Power Planning Committee of the New England Governors Conference, Inc. Attachment 6 identifies the service list of entities to whom this filing has been sent.

E. Brief Description of Rate Change – Section 35.13(b)(4)

See Sections I.C and I.D above.

F. Requisite Agreement for Rate Change – Section 35.13(b)(6)

The PTOs, acting jointly, in accordance with Section 3.04(b) of the TOA among the PTOs and ISO-NE, and with the Rate Design and Funds Disbursement Agreement, have the right to revise the design of the rates and charges for service provided over PTF. On July 27, 2016,

[28] *See, e.g., Public Service Electric & Gas Co.*, 124 FERC ¶ 61,303 (2008); *Am. Elec. Power Serv. Corp.*, 120 FERC ¶ 61,205 (2007).

the PTO AC held a vote which endorsed the enclosed tariff revisions and authorized this filing. No other agreement is necessary for the rate change.[29]

G. Statement Showing Expenses or Cost Included in Cost of Service Statements – Section 35.13(b)(7)

None of the costs related to this filing have been alleged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory practices.

III. CONCLUSION

For the reasons stated above, the PTO AC respectfully requests that the Commission accept the enclosed revisions to Attachment F, to be effective June 1, 2016. The PTO AC requests all necessary waivers of any additional Commission regulations in order to permit the included Tariff records to become effective on the date requested.

Respectfully submitted,

/s/ *Mary E. Grover*
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Attachments

Cc: Persons and Entities identified in Attachments 5 and 6

[29] Pursuant to Section 3.04(b) of the TOA, the PTO AC has the right to propose changes under section 205 of the Federal Power Act to the rates and charges in Attachment F for transmission service pursuant to which the revenue requirements for all transmission facilities of the PTOs used for the provision of transmission service are recovered. Stakeholder notification of such proposed changes is required pursuant to Section 3.04(l) of the TOA. The PTO AC presented the proposed changes to Attachment F included in this filing to the NEPOOL Transmission Committee for an advisory vote at its July 26, 2016 meeting, receiving a 100% favorable vote. The PTO AC similarly presented the proposed tariff changes for an advisory vote by the NEPOOL Participants Committee in a meeting on August 5, 2016, the date of this filing, and received a 100% favorable vote. The PTO AC also notes that the tariff changes proposed in this filing were presented for review to ISO-NE, who confirmed that the proposed filing will not be inconsistent with the design of the New England Markets, as accepted or approved by the FERC, and that no ISO-NE software changes will be necessary to accommodate the proposed tariff changes.

Attachment 1A

Clean Version of Attachment F

ATTACHMENT F
ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF, including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs that are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF pursuant to Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12:

I. The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the Attachment F Implementation Rule contained in this OATT.

ATTACHMENT F

IMPLEMENTATION RULE

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each PTO. Such Transmission Revenue Requirements shall reflect the PTO’s costs for Pool Transmission Facilities (“PTF”) and the Highgate Transmission Facilities (“HTF”), including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each PTO will reflect the PTO’s costs with respect to Pool Supported PTF and the HTF. The Transmission Revenue Requirements will be an annual calculation based on the previous year’s calendar data as shown, in the case of PTOs which are subject to the Commission’s jurisdiction, in the PTO’s FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO’s costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12. The HTF Transmission Revenue Requirements shall be subject to the limitations of inclusion of such costs as set forth in Appendix B to this Attachment. The owners of the HTF, or their designated agent, will submit the annual HTF Transmission Revenue Requirements calculation based on the previous calendar year's cost data from their FERC Form 1 or equivalent information from their official books and records, as appropriate.

The Post-96 Transmission Revenue Requirement for each PTO that is based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on the PTO's PTF transmission plant investments included in the Regional System Plan and placed in-service on or after January 1,2004 (such investments referred to herein as "Post-2003 PTF Investment"). The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment shall incorporate an incentive ROE adder of 100 basis points for plant investment placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157, et al. for any projects included in the RSP, and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments (however; the 125 basis point ROE incentive adder granted to NEEWS under Order No. 679 in Docket No. ER08-1548 and the 50 basis point ROE incentive adder for RTO participation shall not apply to the costs related to the Central Connecticut Reliability Project, consistent with FERC's order) and for MPRP CWIP and NEEWS CWIP. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining each PTO's Incremental Return and Associated Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the PTO's accounting records.

The Post-1996 Pool PTF Rate, as calculated pursuant to Schedule 9, shall include for each PTO a Forecasted Transmission Revenue Requirement calculated in accordance with Appendix C to this Attachment F Implementation Rule. Additionally, the Pre-1997 and Post-1996 Pool PTF Rates shall include an Annual True-up calculated in accordance with Appendix C to this Attachment F Implementation Rule.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year.Further, the informational filing with respect to the determination of the Pool PTF Rate will include a breakdown by PTO of the amount of the change in PTF and HTF investment during the prior year and the PTF and HTF retirements or additions causing such change to beginning and end-of-year PTF balances and HTF balances (although beginning-of-year PTF balances and HTF balances are not used in the formula itself), and any additions to PTF and HTF, retirements of PTF and HTF, and reclassifications of PTF and HTF during the year for each PTO. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs will file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the ISO website. The filing of the information filing does not re-open the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing.

The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term "agreed-upon procedures" shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries including those of affiliated Companies to the PTO's total direct wages and salaries including those of the Affiliates' Companies and excluding administrative and general wages and salaries.

2. PTF/HTF Transmission Plant Allocation Factor shall equal the ratio of PTF/HTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF (Phase I/II HVDC-TF Leases).

3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, and Transmission Related Intangible and General Plant to Total Plant in service excluding Phase I/II HVDC-TF Leases.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the PTO's transmission expenses as recorded in FERC Account No. 403.

General Plant shall equal the PTO's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the PTO's general expenses as recorded in FERC Account No. 403 and NSTAR Electric's FERC Account No. 404 for items subject to amortization.

General Plant Amortization Reserve shall equal NSTAR Electric's general reserve balance as recorded in FERC Account No. 111.

HTF Transmission Plant shall equal the PTO's balance of investment in the Highgate Transmission Facilities as recorded in FERC Account Nos. 350-359.

Intangible Plant shall equal NSTAR Electric's gross plant balance as recorded in FERC Account No. 303. The only allowable Intangible Plant for inclusion are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal NSTAR Electric's amortization expenses as recorded in FERC Account Nos. 404-405. The only allowable Intangible Plant Amortization Expense for inclusion is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal NSTAR Electric's amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion is that related to the amortization of software, patent or rights costs.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107 for costs determined to be Pool- Supported PTF in accordance with Schedule 12 of this OATT.

Merger-Related Costs shall equal NSTAR Electric Company's ("NSTAR Electric"), CL&P's, Public Service Company of New Hampshire's ("PSNH") and WMECO's amortized merger-related costs as authorized by FERC or by state regulatory order.

New England East-West Solution Construction Work in Progress ("NEEWS CWIP") shall equal the NEEWS CWIP balances of The Connecticut Light and Power Company ("CL&P") and Western Massachusetts Electric Company ("WMECO") and New England Power Company ("NEP") as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - shall equal NSTAR Electric's, CL&P's, PSNH's and WMECO's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1.

Phase I/II HVDC-TF Leases shall equal the PTO's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No.105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Transmission Plant shall equal the PTO's transmission plant as defined in the Section II.49 of the OATT and determined in accordance with Appendix A of this Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

PTF/HTF Transmission Plant Investment shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF Transmission Plant.

Total Accumulated Deferred Income Taxes shall equal the net of the PTO's deferred tax balance as recorded in FERC Account Nos. 281-283 and the PTO's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

Transmission Merger-Related Costs shall equal NSTAR Electric's, CL&P's, PSNH's and WMECO's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Phase I/II HVDC-TF expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP), (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT, (O) Transmission Rents Received from Electric Property and (P) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements. The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment for each PTO shall be calculated using the investment base components specifically identified in Section A. 1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, Transmission Investment Base will only include Sections II.A. 1 .(a), (d), (e), (k), and (1) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of(a) PTF/HTF Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation and Amortization Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Loss on Re.acquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital, plus (k) MPRP CWIP, plus (l) NEEWS CWIP.

(a) PTF Transmission Plant will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post2003 PTF Transmission Plant shall be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of the PTO's balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the PTO's balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(d) Transmission Related Depreciation and Amortization Reserve shall equal the PTO's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of the sum of Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve, and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO's balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.

(e) Transmission Related Accumulated Deferred Taxes shall equal the PTO’s electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO’s balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, to Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.

(f) Transmission Related Loss on Reacquired Debt shall equal the PTO’s electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal the PTO’s electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO’s electric balance of FAS 109 multiplied by the Plant Allocation Factor, plus NSTAR Electric’s, CL&P’s, PSNH’s and WMECO’s unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission

Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(k) MPRP CWIP shall equal CMP's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and in accordance with CMP's Accounting Procedures for MPRP CWIP. In order to calculate the Incremental Return and Associated Income Taxes for MPRP CWIP, MPRP CWIP shall be separately identified.

(l) NEEWS CWIP shall equal CL&P, WMECO and NEP's balances as recorded in FERC Account No. 107 for the NEEWS as authorized by Commission order and in accordance with the companies' respective Accounting Procedures for NEEWS CWIP. In order to calculate the Incremental Return and Associated Income Taxes for NEEWS CWIP, NEEWS CWIP shall be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (e) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, shall only reflect item (iii) below and shall apply in the manner indicated below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-1997 and post-1996 assets, the ROE is 11.07%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; (2) any ROE incentive approved by the FERC under Order No. 679 for other plant investments (however; the 125 basis point ROE incentive adder granted to NEEWS under Order No. 679 in Docket No. ER08-1548 and the 50 basis point ROE incentive adder for RTO participation shall not apply to the costs related to the Central Connecticut Reliability Project, consistent with FERC's order) and MPRP CWIP and NEEWS CWIP, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period, and (3) the ratio that common equity is to the PTO's total capital) [1]

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{I\text{-}FT}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections ll.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section ll.B., and D is Transmission Investment Base, as determined in Section II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental Federal Income Tax shall equal

$\underline{(A' * FT)}$

[1] FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

(1 -FT)

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section ll.D.below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B.. D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. <u>Transmission Depreciation and Amortization Expense</u> shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of (i) the PTO's Depreciation Expense for Transmission Plant, plus (ii) an allocation of Intangible Plant Amortization Expense and (iii) General Plant Depreciation and Amortization Expense calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation and Amortization Expense by the Transmission Wages and Salaries Allocation Factor.

C. <u>Transmission Related Amortization of Loss on Reacquired Debt</u> shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

D. <u>Transmission Related Amortization of Investment Tax Credits</u> shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

E. <u>Transmission Related Municipal Tax Expense</u> shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

F. <u>Transmission Related Payroll Tax Expense</u> shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

G. <u>Transmission Operation and Maintenance Expense</u> shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.

H. <u>Transmission Related Administrative and General Expenses</u> shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1 plus Transmission Merger-Related Costs. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

I. <u>Transmission Related Integrated Facilities Charges</u> shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.

J. <u>Transmission Support Revenues</u> shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule

12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.

K. Transmission Support Expense shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for Regional Network Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.

M. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.

N. Revenues for Short-Term service under the OATT shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.

O. Transmission Rents Received from Electric Property shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.

P. Transmission Revenues from MGTSAs shall equal any MGTSA revenues recorded in Account 456.

APPENDIX A TO ATTACHMENT F
IMPLEMENTATION RULE RULES FOR DETERMINING
INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:

   a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

   b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

c. lines that are normally operated open.

d. those that are classified as MTF.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).

3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in "1" and "2" above, then such PTO's connection to PTF will constitute PTF if both of the following requirements are met for this connection:

a. The connection is rated 69 kV or above.

b. The connection is the principal transmission link between the PTO and the remainder of the ISO PTF network.

The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the PTO's system.

4. R/W and land required for the installation of PTF facilities listed in "1", "2", or "3" (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of PTF and Non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The PTOs shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalog of PTF facilities.

All new facilities being installed should be properly classified at the time the facilities are approved under Section I.3.9 of the Transmission, Markets and Services Tariff.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines in consultation with the PTO Administrative Committee determines that treatment of the facility as PTF will facilitate accomplishment of the ISO’s objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as “owned” or “supported,” as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO’s Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.

3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in

such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.

12. The PTO Administrative Committee may designate appropriate facilities as PTF.

Section C: Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.

3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

   a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

   b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

   c. Where a R/W is widened, but the new facilities, either PTF or Non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.

4. In allocating R/W between PTF and Non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae.

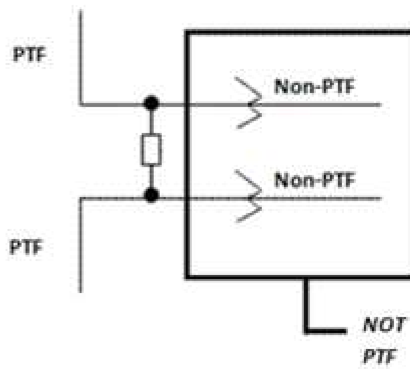
   a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

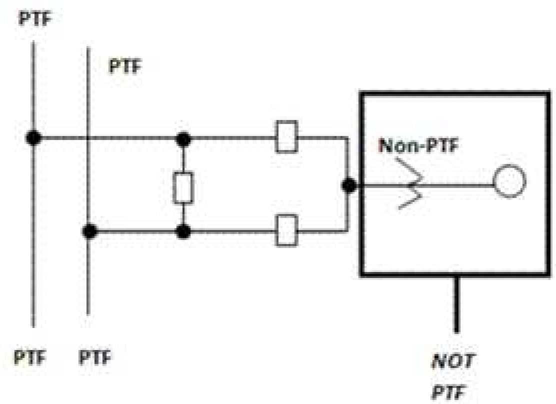
   b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

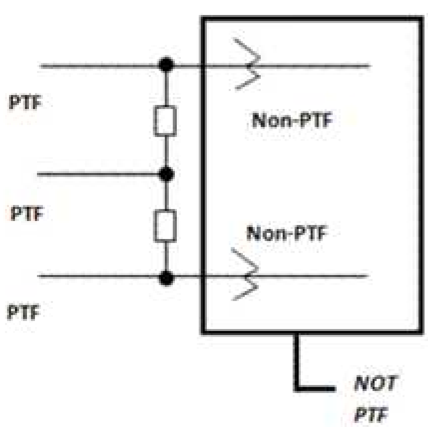
5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the PTO Administrative Committee included under paragraph 1.

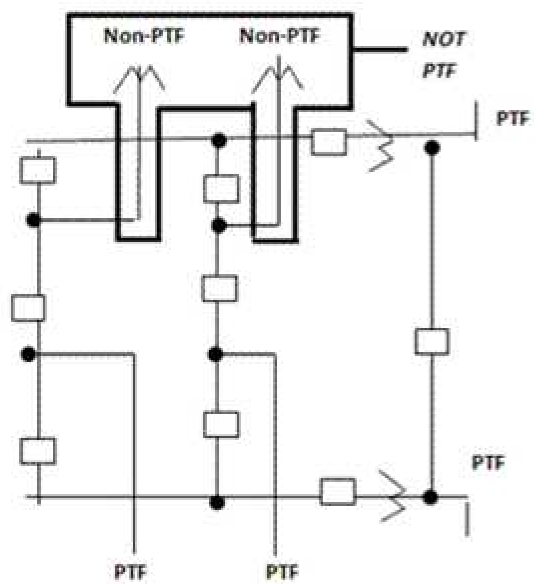
ATTACHMENT 1 TO APPENDIX A TO
ATTACHMENT F IMPLEMENTATION RULE

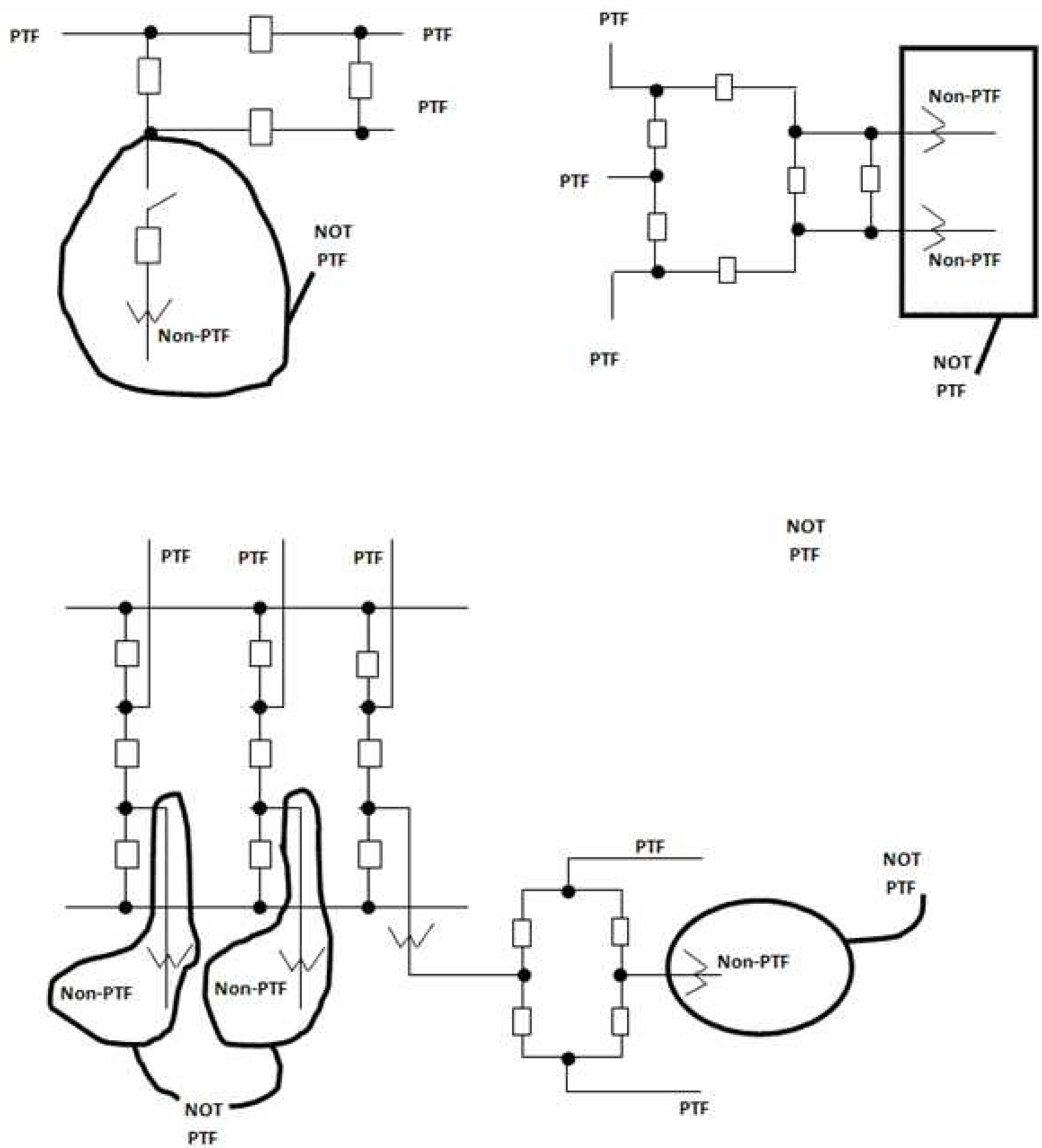
Examples of the Methods for Distinguishing PTF
from Non-PTF Terminal Facilities
in a Number of Typical Substation Configurations







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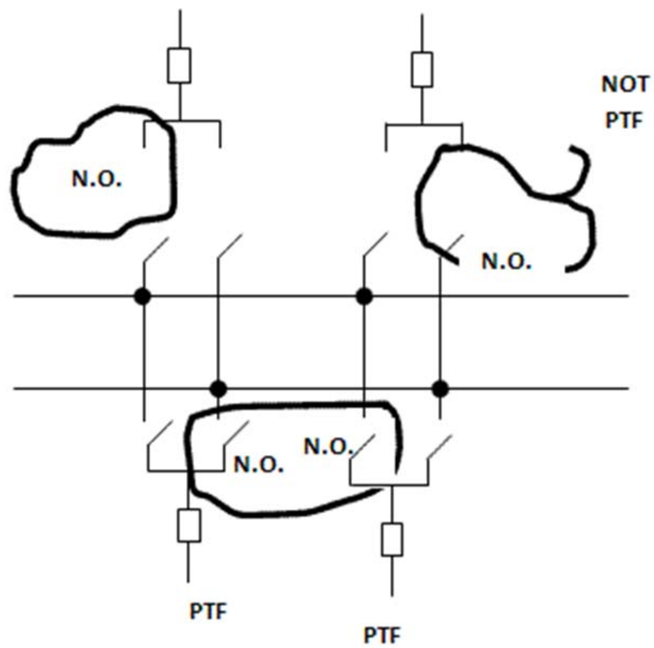

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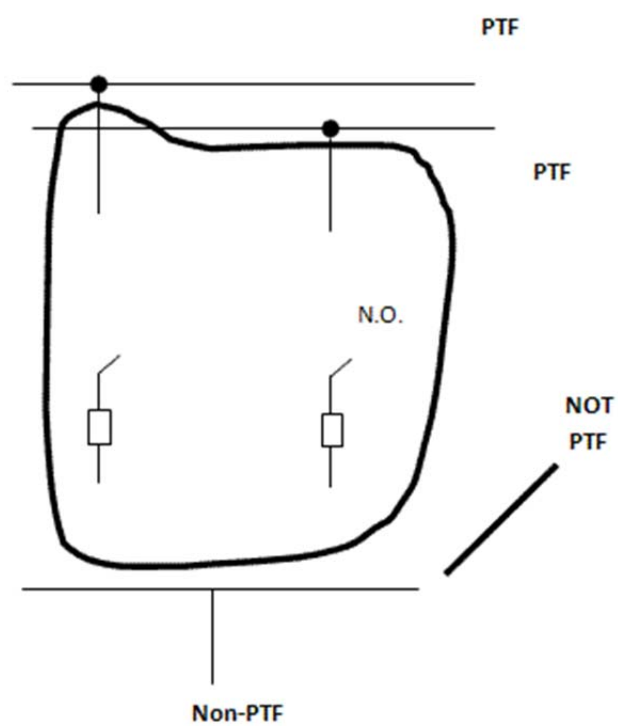

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APPENDIX B TO ATTACHMENT F IMPLEMENTATION RULE

HTF TRANSITION SCHEDULE

The inclusion of HTF Annual Transmission Revenue Requirements in Attachment F (and the calculation of the Pool PTF Rate) to this OATT will be limited by the provisions of this schedule.

VELCO, as a PTO and acting as agent for the HTF owners, may include the HTF Annual Transmission revenue Requirements (i.e., HTF Transmission Plant) within the Attachment F calculations. Additionally, the total HTF Annual Transmission Revenue Requirements included shall be limited to the following:

Year 1: A maximum of $1.2M in Year 1. For the sole purpose of this Schedule, "Year 1" shall be defined as the first full year after the Operations Date:

Year 2: A maximum of $2.0M in Year 2. For the sole purpose of this Schedule, "Year 2" shall be defined as the second full year after the Operations Date;

Year 3: A maximum of $2.8M in Year 3. For the sole purpose of this Schedule, "Year 3" shall be defined as the third full year after the Operations Date;

Year 4: A maximum of $3.5M in Year 4. For the sole purpose of this Schedule, "Year 4" shall be defined as the fourth full year after the Operations Date;

and

Year 5 and thereafter: All HTF Annual Transmission Revenue Requirements shall be included in Attachment F.

ATTACHMENT F IMPLEMENTATION RULE
APPENDIX C

I. DEFINITIONS

(i) Adjusted Carrying Charge Factor (ACCF): shall equal the sum of the Carrying Charge Factor and the quotient of (i) the Cost of Capital Rate multiplied by the PTOs' Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant for the most recently concluded calendar year, and (ii) Post-1996 PTF Transmission Plant for the most recently concluded calendar year, as shown:

ACCF = CCF + [(COC * Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant) ÷ Post-1996 PTF Transmission Plant]

(ii) Annual True-up – Pre-1997 (ATU): shall be the difference between the actual Pre-1997 Annual Transmission Revenue Requirements and the as-billed Pre-1997 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Pre-1997 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Pre-1997 PTF cost data for the most recently concluded calendar year. The as-billed Pre-1997 Annual Transmission Revenue Requirements shall be those Pre-1997 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year.

(iii) Annual True-up – Post-1996 (ATU'): shall be the difference between the actual Post-1996 Annual Transmission Revenue Requirements and the as-billed Post-1996 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Post-1996 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Post-1996 PTF cost data for the most recently concluded calendar year.The as-billed Post-1996 Annual Transmission Revenue Requirements shall be those Post-1996 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year and which included the sum of the Post-1996 Transmission

Revenue Requirements for the year prior to the most recently concluded calendar year plus the Forecasted Transmission Revenue Requirements for the most recently concluded calendar year.

(iv) Carrying Charge Factor (CCF): shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A, excluding MPRP CWIP and NEEWS CWIP, through II.H divided by Attachment F Section II.A.1.a.

(v) Cost of Capital Rate (COC): shall be determined in accordance with Attachment F Section II.A.2.

(vi) Forecast Period: The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.

(vii) Forecasted ADIT (FADIT): shall equal the PTOs' projected change in Accumulated Deferred Income Taxes from the most recently concluded calendar year related to accelerated depreciation and associated with PTF Transmission Plant for the Forecast Period calculated in accordance with Treasury regulation Section 1.167(l)-1(h)(6).

(viii) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P's estimated incremental change in NEEWS CWIP for the Forecast Period.

(ix) Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated incremental change in MPRP CWIP for the Forecast Period.

(x) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xi) Forecasted Transmission Plant Additions (FTPA): shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.

(xii) Forecasted Transmission Revenue Requirement (FTRR): shall equal FTPA multiplied by the ACCF, minus FADIT multiplied by the COC, plus FCWIP multiplied by the MCOC, plus FCCWIP multiplied by CCOC, plus FWCWIP multiplied by WCOC, plus FNCWIP multiplied by NCOC, as shown:

FTRR = (FTPA * ACCF) - (FADIT * COC) + (FCWIP * MCOC) + (FCCWIP * CCOC) + (FWCWIP * WCOC) + (FNCWIP * NCOC)

(xiii) <u>Forecasted WMECO NEEWS CWIP (FWCWIP)</u>: shall equal WMECO's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xiv) <u>MPRP Cost of Capital Rate (MCOC)</u>: shall be determined in accordance with Attachment F Section II.A.2.

(xv) <u>NEEWS CL&P Cost of Capital Rate (CCOC)</u>: shall be determined in accordance with Attachment F Section II.A.2.

(xvi) <u>NEEWS WMECO Cost of Capital Rate (WCOC)</u>: shall be determined in accordance with Attachment F Section II.A.2.

(xvii) <u>NEEWS NEP Cost of Capital Rate (NCOC)</u>: shall be determined in accordance with Attachment F Section II.A.2.

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

The PTOs' annual informational filing shall include supporting documentation for their estimated capital additions to be placed in service during the current calendar year as well as supporting documentation pertaining to any annual true-up and interest calculations.

Attachment 1B

Redlined Version of Attachment F

ATTACHMENT F

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF, including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs that are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF pursuant to Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12:

I. The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the Attachment F Implementation Rule contained in this OATT.

ATTACHMENT F

IMPLEMENTATION RULE

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each PTO. Such Transmission Revenue Requirements shall reflect the PTO's costs for Pool Transmission Facilities ("PTF") and the Highgate Transmission Facilities ("HTF"), including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12. The HTF Transmission Revenue Requirements shall be subject to the limitations of inclusion of such costs as set forth in Appendix B to this Attachment. The owners of the HTF, or their designated agent, will submit the annual HTF Transmission Revenue Requirements calculation based on the previous calendar year's cost data from their FERC Form 1 or equivalent information from their official books and records, as appropriate.

The Post-96 Transmission Revenue Requirement for each PTO that is based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on the PTO's PTF transmission plant investments included in the Regional System Plan and placed in-service on or after January 1,2004 (such investments referred to herein as "Post-2003 PTF Investment"). The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment shall incorporate an incentive ROE adder of 100 basis points for plant investment placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157, et al. for any projects included in the

RSP, and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments (however; the 125 basis point ROE incentive adder granted to NEEWS under Order No. 679 in Docket No. ER08-1548 and the 50 basis point ROE incentive adder for RTO participation shall not apply to the costs related to the Central Connecticut Reliability Project, consistent with FERC's order) and for MPRP CWIP and NEEWS CWIP. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining each PTO's Incremental Return and Associated Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the PTO's accounting records.

The Post-1996 Pool PTF Rate, as calculated pursuant to Schedule 9, shall include for each PTO a Forecasted Transmission Revenue Requirement calculated in accordance with Appendix C to this Attachment F Implementation Rule. Additionally, the Pre-1997 and Post-1996 Pool PTF Rates shall include an Annual True-up calculated in accordance with Appendix C to this Attachment F Implementation Rule.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year.Further, the informational filing with respect to the determination of the Pool PTF Rate will include a breakdown by PTO of the amount of the change in PTF and HTF investment during the prior year and the PTF and HTF retirements or additions causing such change to beginning and end-of-year PTF balances and HTF balances (although beginning-of-year PTF balances and HTF balances are not used in the formula itself), and any additions to PTF and HTF, retirements of PTF and HTF, and reclassifications of PTF and HTF during the year for each PTO. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs will file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the ISO website. The filing of the information filing does not re-open the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing.

The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term “agreed-upon procedures” shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. <u>Transmission Wages and Salaries Allocation Factor</u> shall equal the ratio of Transmission-related direct wages and salaries including those of affiliated Companies to the PTO’s total direct wages and salaries including those of the Affiliates’ Companies and excluding administrative and general wages and salaries.

2. <u>PTF/HTF Transmission Plant Allocation Factor</u> shall equal the ratio of PTF/HTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF (Phase I/II HVDC-TF Leases).

3. <u>Plant Allocation Factor</u> shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, and Transmission Related Intangible and General Plant to Total Plant in service excluding Phase I/II HVDC-TF Leases.

B. TERMS

<u>Administrative and General Expense</u> shall equal the PTO’s expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

<u>Amortization of Loss on Reacquired Debt</u> shall equal the PTO’s expenses as recorded in FERC Account No. 428.1.

<u>Amortization of Investment Tax Credits</u> shall equal the PTO’s credits as recorded in FERC Account No. 411.4.

<u>Depreciation Expense for Transmission Plant</u> shall equal the PTO’s transmission expenses as recorded in FERC Account No. 403.

<u>General Plant</u> shall equal the PTO’s gross plant balance as recorded in FERC Account Nos. 389-399.

<u>General Plant Depreciation and Amortization Expense</u> shall equal the PTO’s general expenses as recorded in FERC Account No. 403 and NSTAR Electric’s FERC Account No. 404 for items subject to amortization.

<u>General Plant Amortization Reserve</u> shall equal NSTAR Electric’s general reserve balance as recorded in FERC Account No. 111.

<u>HTF Transmission Plant</u> shall equal the PTO's balance of investment in the Highgate Transmission Facilities as recorded in FERC Account Nos. 350-359.

<u>Intangible Plant</u> shall equal NSTAR Electric’s gross plant balance as recorded in FERC Account No. 303. The only allowable Intangible Plant for inclusion are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal NSTAR Electric's amortization expenses as recorded in FERC Account Nos. 404-405. The only allowable Intangible Plant Amortization Expense for inclusion is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal NSTAR Electric's amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion is that related to the amortization of software, patent or rights costs.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107 for costs determined to be Pool- Supported PTF in accordance with Schedule 12 of this OATT.

Merger-Related Costs shall equal NSTAR Electric Company's ("NSTAR Electric"), CL&P's, Public Service Company of New Hampshire's ("PSNH") and WMECO's amortized merger-related costs as authorized by FERC or by state regulatory order.

New England East-West Solution Construction Work in Progress ("NEEWS CWIP") shall equal the NEEWS CWIP balances of The Connecticut Light and Power Company ("CL&P") and Western Massachusetts Electric Company ("WMECO") and New England Power Company ("NEP") as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - shall equal NSTAR Electric's, CL&P's, PSNH's and WMECO's unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1.

Phase I/II HVDC-TF Leases shall equal the PTO's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No.105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Transmission Plant shall equal the PTO's transmission plant as defined in the Section II.49 of the OATT and determined in accordance with Appendix A of this Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

PTF/HTF Transmission Plant Investment shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF Transmission Plant.

Total Accumulated Deferred Income Taxes shall equal the net of the PTO's deferred tax balance as recorded in FERC Account Nos. 281-283 and the PTO's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

Transmission Merger-Related Costs shall equal NSTAR Electric's, CL&P's, PSNH's and WMECO's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Phase I/II HVDC-TF expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP), (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G)

Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT, (O) Transmission Rents Received from Electric Property and (P) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements. The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment for each PTO shall be calculated using the investment base components specifically identified in Section A. 1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, Transmission Investment Base will only include Sections II.A. 1 .(a), (d), (e), (k), and (1) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of(a) PTF/HTF Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation and Amortization Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Loss on Re.acquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h)
Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital, plus (k) MPRP CWIP, plus (l) NEEWS CWIP.

(a) PTF Transmission Plant will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) the Pre-1997

PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post2003 PTF Transmission Plant shall be separately identified.

(b) Transmission Related Intangible and General Plant shall equal the sum of the PTO's balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the PTO's balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(d) Transmission Related Depreciation and Amortization Reserve shall equal the PTO's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of the sum of Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve, and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO's balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.

(e) Transmission Related Accumulated Deferred Taxes shall equal the PTO’s electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO’s balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, to Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.

(f) Transmission Related Loss on Reacquired Debt shall equal the PTO’s electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal the PTO’s electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO’s electric balance of FAS 109 multiplied by the Plant Allocation Factor, plus NSTAR Electric’s, CL&P’s, PSNH’s and WMECO’s unamortized balance of merger-related transmission costs recorded in FERC Account No. 182.3 as authorized by FERC. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

(k) MPRP CWIP shall equal CMP's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and in accordance with CMP's Accounting Procedures for MPRP CWIP. In order to calculate the Incremental Return and Associated Income Taxes for MPRP CWIP, MPRP CWIP shall be separately identified.

(l) NEEWS CWIP shall equal CL&P, WMECO and NEP's balances as recorded in FERC Account No. 107 for the NEEWS as authorized by Commission order and in accordance with the companies' respective Accounting Procedures for NEEWS CWIP. In order to calculate the Incremental Return and Associated Income Taxes for NEEWS CWIP, NEEWS CWIP shall be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (e) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, shall only reflect item (iii) below and shall apply in the manner indicated below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-1997 and post-1996 assets, the ROE is 11.07%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; (2) any ROE incentive approved by the FERC under Order No. 679 for other plant investments (however; the 125 basis point ROE incentive adder granted to NEEWS under Order No. 679 in Docket No. ER08-1548 and the 50 basis point ROE incentive adder for RTO participation shall not apply to the costs related to the Central Connecticut Reliability Project, consistent with FERC’s order) and MPRP CWIP and NEEWS CWIP, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period, and (3) the ratio that common equity is to the PTO's total capital) [1]

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{I-FT}$$

[1] FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections ll.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section ll.B., and D is Transmission Investment Base, as determined in Section II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section ll.D.below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B.. D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP and NEEWS CWIP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of (i) the PTO's Depreciation Expense for Transmission Plant, plus (ii) an allocation of Intangible Plant Amortization Expense and (iii) General Plant Depreciation and Amortization Expense calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation and Amortization Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.

H. Transmission Related Administrative and General Expenses shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1 plus Transmission Merger-Related Costs. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

I. Transmission Related Integrated Facilities Charges shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.

J. Transmission Support Revenues shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule 12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.

K. Transmission Support Expense shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for

Regional Network Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.

M. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.

N. Revenues for Short-Term service under the OATT shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.

O. Transmission Rents Received from Electric Property shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.

P. Transmission Revenues from MGTSAs shall equal any MGTSA revenues recorded in Account 456.

APPENDIX A TO ATTACHMENT F

IMPLEMENTATION RULE RULES FOR DETERMINING

INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:

   a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

c. lines that are normally operated open.

d. those that are classified as MTF.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).

3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in "1" and "2" above, then such PTO's connection to PTF will constitute PTF if both of the following requirements are met for this connection:

a. The connection is rated 69 kV or above.

b. The connection is the principal transmission link between the PTO and the remainder of the ISO PTF network.

The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the PTO's system.

4. R/W and land required for the installation of PTF facilities listed in "1", "2", or "3" (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of PTF and Non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The PTOs shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalog of PTF facilities.

All new facilities being installed should be properly classified at the time the facilities are approved under Section I.3.9 of the Transmission, Markets and Services Tariff.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines in consultation with the PTO

Administrative Committee determines that treatment of the facility as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.

3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise

supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.

12. The PTO Administrative Committee may designate appropriate facilities as PTF.

Section C: Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.

3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

   a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

   b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

c. Where a R/W is widened, but the new facilities, either PTF or Non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.

4. In allocating R/W between PTF and Non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae.

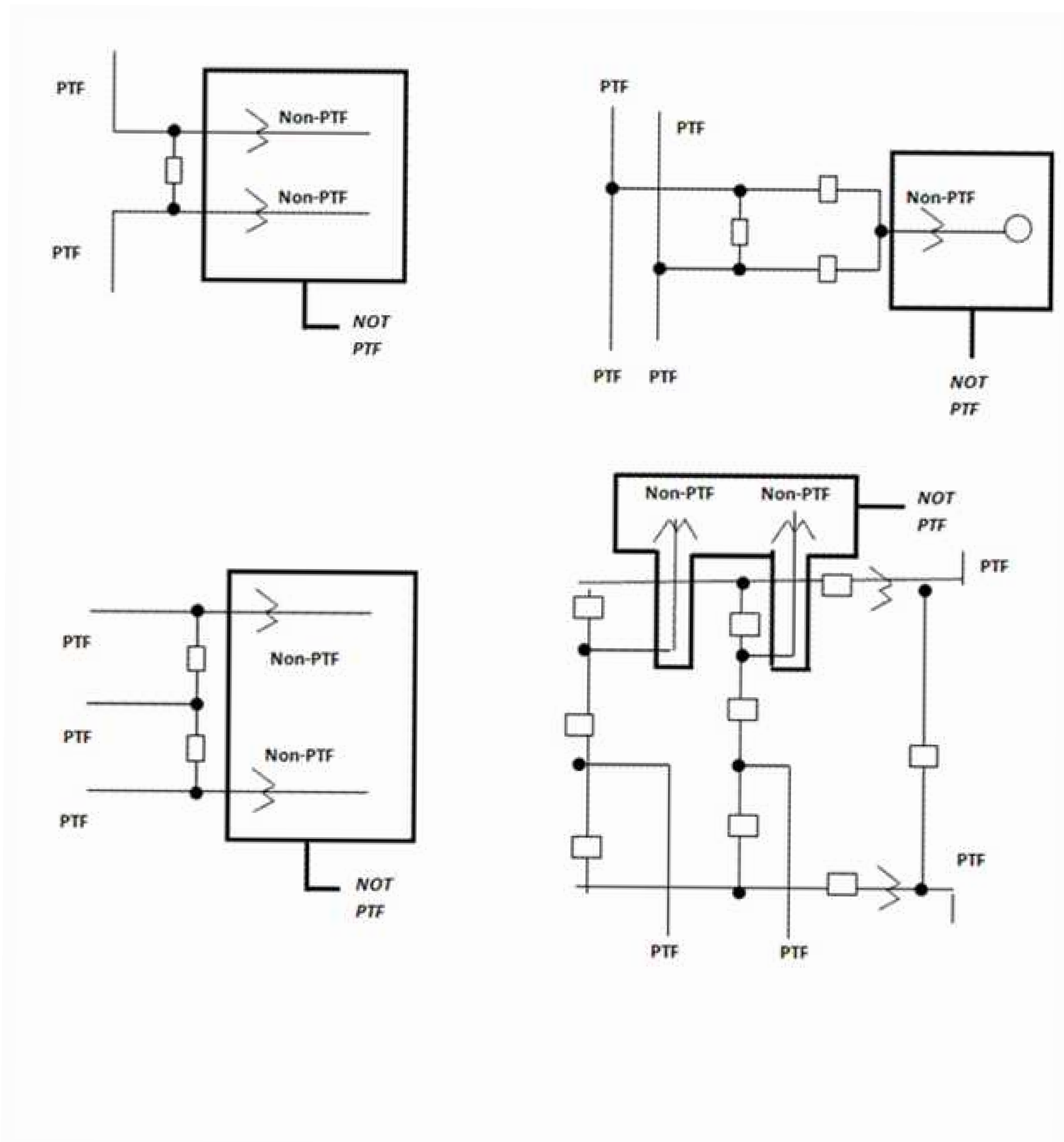
a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the PTO Administrative Committee included under paragraph 1.

ATTACHMENT 1 TO APPENDIX A TO
ATTACHMENT F IMPLEMENTATION RULE

Examples of the Methods for Distinguishing PTF
from Non-PTF Terminal Facilities
in a Number of Typical Substation Configurations



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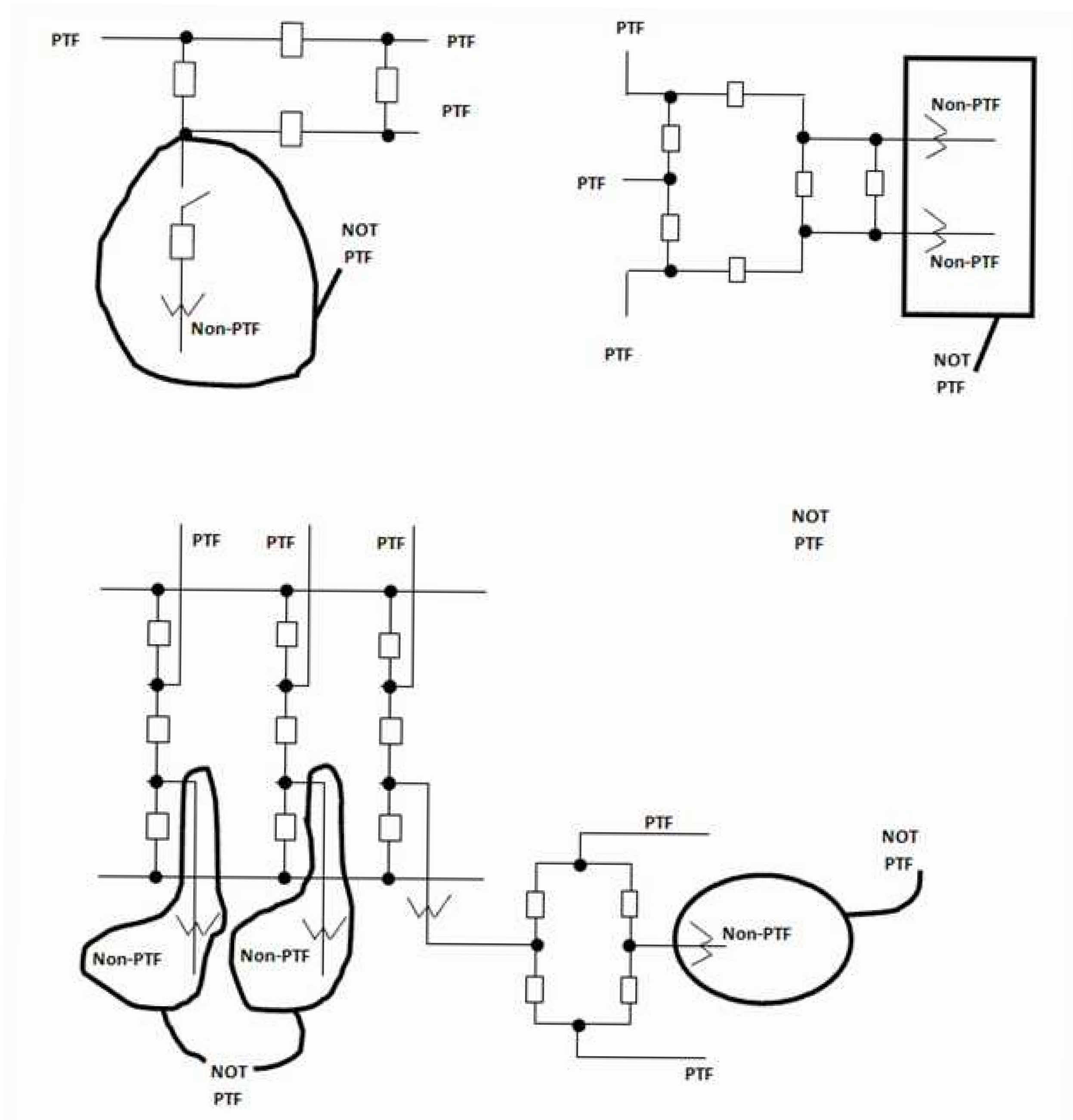
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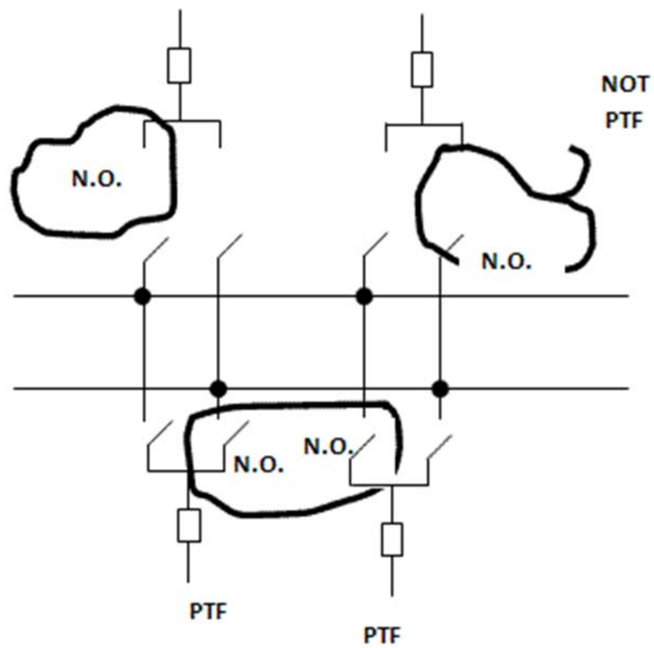
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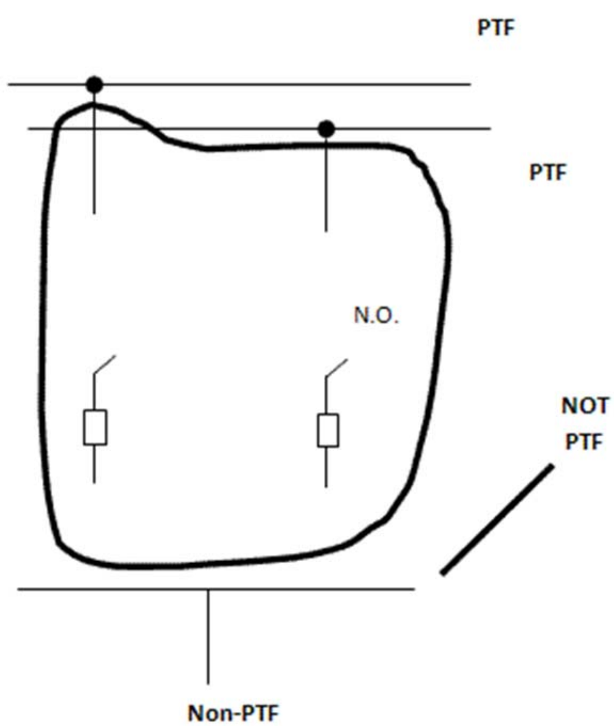
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APPENDIX B TO ATTACHMENT F IMPLEMENTATION RULE

HTF TRANSITION SCHEDULE

The inclusion of HTF Annual Transmission Revenue Requirements in Attachment F (and the calculation of the Pool PTF Rate) to this OATT will be limited by the provisions of this schedule.

VELCO, as a PTO and acting as agent for the HTF owners, may include the HTF Annual Transmission revenue Requirements (i.e., HTF Transmission Plant) within the Attachment F calculations. Additionally, the total HTF Annual Transmission Revenue Requirements included shall be limited to the following:

Year 1: A maximum of $1.2M in Year 1. For the sole purpose of this Schedule, "Year 1" shall be defined as the first full year after the Operations Date:

Year 2: A maximum of $2.0M in Year 2. For the sole purpose of this Schedule, "Year 2" shall be defined as the second full year after the Operations Date;

Year 3: A maximum of $2.8M in Year 3. For the sole purpose of this Schedule, "Year 3" shall be defined as the third full year after the Operations Date;

Year 4: A maximum of $3.5M in Year 4. For the sole purpose of this Schedule, "Year 4" shall be defined as the fourth full year after the Operations Date;

and

Year 5 and thereafter: All HTF Annual Transmission Revenue Requirements shall be included in Attachment F.

ATTACHMENT F IMPLEMENTATION RULE

APPENDIX C

I. DEFINITIONS

(i) **Adjusted Carrying Charge Factor (ACCF): shall equal the sum of the Carrying Charge Factor and the quotient of (i) the Cost of Capital Rate multiplied by the PTOs' Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant for the most recently concluded calendar year, and (ii) Post-1996 PTF Transmission Plant for the most recently concluded calendar year, as shown:**

ACCF = CCF + [(COC * Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant) ÷ Post-1996 PTF Transmission Plant]

(ii) Annual True-up – Pre-1997 (ATU): shall be the difference between the actual Pre-1997 Annual Transmission Revenue Requirements and the as-billed Pre-1997 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Pre-1997 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Pre-1997 PTF cost data for the most recently concluded calendar year. The as-billed Pre-1997 Annual Transmission Revenue Requirements shall be those Pre-1997 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year.

([~~ii~~]**iii**) Annual True-up – Post-1996 (ATU'): shall be the difference between the actual Post-1996 Annual Transmission Revenue Requirements and the as-billed Post-1996 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Post-1996 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Post-1996 PTF cost data for the most recently concluded calendar year.The as-billed Post-1996 Annual Transmission Revenue Requirements shall be those Post-1996 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year and which included the sum of the Post-1996 Transmission Revenue Requirements for the year prior to the most recently concluded calendar year plus the Forecasted Transmission Revenue Requirements for the most recently concluded calendar year.

[~~(iii~~]~~)~~ ~~Forecast Period: The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.~~

(iv) ~~Forecasted Transmission Plant Additions (FTPA): shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.~~

[~~(v~~]~~)~~ ~~Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated incremental change in~~[~~MPRPCWIP for the Forecast Period.~~]][~~(vi)~~]Carrying Charge Factor (CCF): shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A, excluding MPRP CWIP and NEEWS CWIP, through II.H divided by Attachment F Section II.A.1.a.

([~~vii)~~ ~~MPRP~~]**v)** Cost of Capital Rate ([~~MCOC~~]**COC**): shall be determined in accordance with Attachment F Section II.A.2.

(vi) Forecast Period: The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.

(vii) Forecasted ADIT (FADIT): shall equal the PTOs' projected change in Accumulated Deferred Income Taxes from the most recently concluded calendar year related to accelerated depreciation and associated with PTF Transmission Plant for the

Forecast Period calculated in accordance with Treasury regulation Section 1.167(l)-1(h)(6).

(viii) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P's estimated incremental change in NEEWS CWIP for the Forecast Period.

(ix) Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated incremental change in **MPRP CWIP for the Forecast Period.**

(x) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP's estimated incremental change in NEEWS CWIP for the Forecast Period.

(xi) Forecasted Transmission Plant Additions (FTPA): shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.

([~~viii~~]**xii**) Forecasted Transmission Revenue Requirement (FTRR): shall equal FTPA multiplied by the [~~CCF~~]**ACCF, minus FADIT multiplied by the COC,** plus FCWIP multiplied by the MCOC, plus FCCWIP multiplied by CCOC, plus FWCWIP multiplied by WCOC, plus FNCWIP multiplied by NCOC, as shown:

FTRR = **(**FTPA * [~~CCF~~]**ACCF) - (FADIT * COC)** + (FCWIP * MCOC) + (FCCWIP * CCOC) + (FWCWIP * WCOC) + (FNCWIP * NCOC)

[~~(ix~~]~~) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P's estimated incremental change in NEEWS CWIP for the Forecast Period.~~

~~(x~~ **(xiii**) Forecasted WMECO NEEWS CWIP (FWCWIP): shall equal WMECO's estimated incremental change in NEEWS CWIP for the Forecast Period.

([~~xi~~]**xiv) MPRP Cost of Capital Rate (MCOC): shall be determined in accordance with Attachment F Section II.A.2.**

(xv) NEEWS CL&P Cost of Capital Rate (CCOC): shall be determined in accordance with Attachment F Section II.A.2.

([~~xii~~]xvi) NEEWS WMECO Cost of Capital Rate (WCOC): shall be determined in accordance with Attachment F Section II.A.2.

[~~(xiii~~]~~) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP's estimated incremental change in NEEWS CWIP for the Forecast Period.~~

([~~xiv~~]xvii) NEEWS NEP Cost of Capital Rate (NCOC): shall be determined in accordance with Attachment F Section II.A.2.

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

The PTOs' annual informational filing shall include supporting documentation for their estimated capital additions to be placed in service during the current calendar year as well as supporting documentation pertaining to any annual true-up and interest calculations.

Attachment 2

June 27, 2016 Notice Provided to Stakeholders in New England

Date: June 27, 2016

To: PTO AC Chair & Vice Chair
NEPOOL Participants Committee Members & Alternates
NEPOOL Transmission Committee Members and Alternates
Executive Director – NECPUC

From: Mary Grover, PTO-AC Legal Work Group Chair

Subject: Notice of Tariff Revisions to Attachment F of the ISO OATT

Pursuant to Section 3.04 of the Transmission Operating Agreement ("TOA"), the PTO-AC, on behalf of several individual PTOs, hereby provides written notification that it will make certain tariff revisions to Section II of the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("the OATT"), pursuant to Section 205 of the Federal Power Act. The proposed tariff revisions are being submitted for the purpose of incorporating recent Internal Revenue Service ("IRS") guidance indicating that when a utility's formula rate is based on a forecasted revenue requirement (even where the forecast is trued up to actuals), the utility should apply a "proration formula" specified by the IRS to estimate the appropriate level of accumulated deferred income taxes ("ADIT") in order to comply with the IRS's normalization requirements. The intended filing will propose a change to Attachment F to the OATT so that it incorporates the IRS proration formula into the calculation of the Forecasted Transmission Revenue Requirement.

The PTO-AC plans to file these tariff revisions with the Federal Energy Regulatory Commission ("FERC") on or about August 5, 2016. The PTOs will request that the tariff revisions be made effective June 1, 2016.

In the good faith judgment of the PTOs, the proposed filing will not be inconsistent with the design of the New England Markets, as accepted or approved by the FERC. The PTOs believe that no ISO-NE software changes will be necessary to accommodate the proposed tariff changes, and will work with ISO New England, Inc. to obtain a definitive answer as to whether any software changes may be necessary prior to filing the proposed Tariff amendments with the FERC.

This notification satisfies all TOA requirements. Please contact Lisa M. Cooper at (860) 665-2453 or lisa.cooper@eversource.com, or Mary Grover at (617) 424-2105 or mary.grover@eversource.com with any questions regarding the proposed filing.

Attachment 3

Supporting Workpapers

Supplement to the Draft PTOAC Informational Filing Dated June 14, 2016

June 15, 2016

Recent Internal Revenue Service ("IRS") private letter rulings have indicated that, when a utility's formula rate is based on a forecasted revenue requirement, the utility should apply a "proration formula" specified by the IRS to estimate the appropriate level of accumulated deferred income taxes ("ADIT"). The Forecasted Transmission Revenue Requirement included in each year's Regional Network Service ("RNS") rate update currently is calculated using a Carrying Charge Factor that reflects the test year historic level of ADIT. This is the approach reflected in the draft of the Informational Filing for the 6/1/2016 OATT Schedule 1 and 9 Tariff Rates posted on the ISO-NE website on June 14, 2016.

A group of New England transmission owners ("TOs") intend to make a filing with FERC in the next several months that will propose a change to Attachment F to the ISO-NE open access transmission tariff so that it explicitly incorporates the IRS proration formula into the calculation of the Forecasted Transmission Revenue Requirement. This change to Attachment F will be presented for advisory review by the appropriate NEPOOL committees. The materials posted with this notice show the calculation of the 6/1/2016 RNS rate with Forecasted Transmission Revenue Requirements calculated using the IRS proration formula consistent with the proposed changes to Attachment F.

The following items are contained in this supplement to the Draft PTOAC informational filing:

1. Attachment 7 - Schedule 9 RNS Rates Effective June 1, 2016 – May 31, 2017 based on 2015 Actual Data, 2016 Forecasted Data and Annual True-up Adjusted to Reflect ADIT Proration.

2. Attachment 8 - PTOs' Annual Transmission Revenue Requirement Calculations Pursuant to Attachment F Based on 2015 Actual Data, 2016 Forecasted Data and Annual True-up Adjusted to Reflect ADIT Proration.

Schedule 9 RNS Rates Effective June 1, 2016 – May 31, 2017
Based on 2015 Actual Data, 2016 Forecasted Data and Annual True-up
Adjusted to Reflect ADIT Proration

PTO 2015 12 CP NETWORK LOADS

Local Networks	2015 Network Load (MW)
Central Maine Power Co.	1,403.442
Emera Maine	248.353
Fitchburg Gas & Electric Light Co.	75.395
New England Power Co.	5,582.393
Eversource Energy Service Company	6,894.113
NSTAR Electric Co.	4,142.840
The United Illuminating Co.	720.803
VT Transco LLC	803.914
Total	19,871.253

Long Term TOUT (MW)	0

PTO RNS Rates for 06/01/16 - 5/31/17	PRE 97 RNS Rate	Post 96 RNS Rate	RNS Rates for June 1, 2016 Adjusted to reflect ADIT proration (a)	RNS Rates Effective June 1, 2016	Delta
Total NE Rev Req	$341,362,939	$1,722,487,505			
Total NE Loads - kW	19,871,253	19,871,253			
Total NE RNS $ / kW-yr.	17.17873	86.68238	103.86111	103.29588	0.56523

(a) A group of New England transmission owners ("TOs") intend to make a filing with FERC in the next several months that will propose a change to Attachment F to the ISO NE transmission tariff so that it explicitly incorporates the IRS proration formula into the calculation of the Forecasted Revenue Requirement.

PTO 2016 Rev Req - Adjusted to reflect ADIT proration

PTO Annual Input Data 2015

		Customer #	DUNS #	DUNS Name	PTF Revenue Requirements Pre-1997 PTF $	PTF Revenue Requirements Post-1996 PTF $	
1		5	17-057-1897	Braintree Electric Light Department	$ 285,758	$ 2,852,291	1
2		6	00-694-8954	**Central Maine Power Company**	$ 14,912,436	$ 229,949,638	2
3		7	11-468-3899	Chicopee Electric Light Department	$ 27,061	$ 565,129	3
4		51386	96-773-8696	Connecticut Transmission Municipal Electric	$ 253,516	$ 9,706,602	4
5		2	00-694-9002	**Emera Maine**	$ 902,314	$ 51,011,385	5
6		112	05-254-3980	**Eversource Energy Service Company**	$ 61,707,456	$ 707,150,472	6
7		38	00-695-4317	**Fitchburg Gas & Electric Light Co.**	$ 283,347	$ 943,871	7
8		44	08-465-0050	Holyoke Gas & Electric Department	$ 1,047,219	$ 2,063,514	8
9		45	10-775-5126	Hudson Light & Power Department	$ 84,350	$ 129,910	9
10		6	06-099-4258	**Maine Electric Power Company**	$ 1,646,182	$ 2,418,617	10
11		76	07-172-4900	Massachusetts Municipal Wholesale Electric	$ 1,036,792	$ 615,970	11
12		79	15-597-6665	Middleborough Gas & Electric Department	$ 60,658	$ 1,034,546	12
13		81	00-695-2881	**New England Power Company**	$178,483,724	$ 239,414,394	13
14		51321	83-132-2677	**New Hampshire Transmission, LLC**	$ 2,999,244	$ 2,512,375	14
15		158	08-421-1572	Norwood Municipal Light Department	$ -	$ 2,761,813	15
16		3	00-695-1552	**NSTAR Electric Company**	$ 44,499,536	$ 200,754,713	16
17		148	86-703-4654	Reading Municipal Light Plant	$ 203,889	$ 324,346	17
18		149	78-451-8870	Shrewsbury Electric and Cable Operations	$ -	$ 439,239	18
19		153	04-661-6033	Taunton Municipal Light Plant	$ 210,053	$ 8,453	19
20	*	185	79-806-8342	Unitil Power Corp.	$ 109,023	$ -	20
21		181	00-691-7967	**United Illuminating Company**	$ 21,149,155	$ 127,393,667	21
22		50853	78-039-9163	**Vermont Transco LLC**	$ 10,508,508	$ 135,307,716	22
22		182	00-579-1934	Vermont Electric Power Co, Inc.	$ 869,855	$ 4,622,830	22
23		51310	01-013-9228	Wallingford Electric	$ 82,862	$ 506,014	23
24				Total	$341,362,939	$ 1,722,487,505	24

* Revenue requirement amounts indicate payments made to support PTF owned by other Participants.

BOLD = Companies PTF RR was adjusted to reflect ADIT proration

PTOs’ Annual Transmission Revenue Requirement Calculations
Pursuant to Attachment F
Based on 2015 Actual Data, 2016 Forecasted Data and Annual True-up
Adjusted to Reflect ADIT Proration

ISO-NE Tariff Billing
PTO Annual Transmission Revenue Requirements
per OATT Attachment F
Adjusted to Reflect ADIT Proration

Submitted on:	June 14, 2016
Revenue Requirements for (test year):	2015
Rates Effective for the period:	June 1, 2016
through:	May 31, 2017
Customer:	Central Maine Power Company
Customer's NABs Number:	06
Name of Participant responsible for customer's billing:	Central Maine Power Company
DUNs number of Participant responsible for customer's billing:	006948954

	Pre-97 Revenue Requirements		**Post-96 Revenue Requirements**	
Total of Attachment F - Sections A through I	= $ 15,009,463	(a)	$ 232,162,895	(f)
Total of Attachment F - Section J - Support Revenue	324,817	(b)	-	(g)
Total of Attachment F - Section K - Support Expense	625,382	(c)	-	(h)
Total of Attachment F - Section (L through O)	(129,095)	(d)	(1,915,451)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	15,180,933	(e)=(a)-(b)+(c)+(d)	230,247,444	(j)
Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)	N/A		5,467,370	(k)
Annual True-up (per Appendix C to Attachment F Implementation Rule)	(425,312)	(l)	(8,179,328)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	**$ 14,755,621**	(n)=(e)+(l)	**$ 227,535,486**	(o)=(j)+(k)+(m)
Prior Year Interest Expense Correction	164,656		2,534,866	
Revenue Requirement Impacts of Income Tax Flow-Through vs. Normalization	(7,841)		(120,714)	
Total with Income Tax Adjustment	**$14,912,436**		**$229,949,638**	

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements, and True-ups (including interest)	**$ 244,862,074**	(p) = (n)+(o)

Central Maine Power
Post-96 RNS Revenue Requirements
Adjusted to Reflect ADIT Proration

Line No.	**FORECASTED TRANSMISSION REVENUE REQUIREMENTS (FTRR)**	**Forecast Period**	**Attachment F Reference Section:**	**Amount**	**Reference**
1	Forecasted Rev Req'ts for FTPA			$ 2,810,793	line 10 below
2	Forecasted Rev Req'ts for FCWIP			2,656,577	line 9 below
3	Forecasted Transmission Revenue Requirements (Lines 1 + 2)			$ 5,467,370	
4	Forecasted Transmission Plant Additions (FTPA)	2015	Appendix C iv	$ 16,498,273	
5	Carrying Charge Factor (CCF)		Appendix C vi	17.61%	line 20 below
6	Subtotal Forecasted Rev Req'ts for FTPA (Lines 1*2)			2,904,525	
7	ADIT Adjustment - IRS Proration			705,761	Worksheet 2_ADIT Proration
8	Cost of Capital Rate			13.28%	Line 33 below
9	Revenue Requirement Associated with ADIT Adjustment (Line 7*Line 8)			93,732	
10	Total Forecasted Rev Req'ts for FTPA (Lines 6 - Line 9)			2,810,793	
11	Forcasted MPRP CWIP (FCWIP)	2015	Appendix C v	$ 19,025,181	Annual Report of Construction Costs
12	MPRP Cost of Capital Rate (MCOC)		Appendix C vii	13.96%	line 23 below
13	Forecasted Rev Req'ts for FCWIP (Lines 11*12)			$ 2,656,577	
	DERIVATION OF CARRYING CHARGE FACTOR (CCF)				
14	Investment Return and Income Taxes		(A)	$ 145,713,006	Worksheet 2a, line 14
15	Depreciation Expense		(B)	34,066,471	Worksheet 1, line 16
16	Amortization of Loss on Reacquired Debt		(C)	129,261	Worksheet 1, line 17
17	Amortization of Investment Tax Credits		(D)	-	Worksheet 1, line 18
18	Municipal Taxes		(E)	18,253,506	Worksheet 1, line 19
19	Payroll Taxes		(F)	-	Worksheet 1, line 20
20	Operation and Maintenance Expense		(G)	17,442,736	Worksheet 1, line 21
21	Administrative and General Expense		(H)	13,807,109	Worksheet 1, line 22
22	Total Expenses (Lines 14 thru 21)			229,412,089	
23	PTF Transmission Plant		(A)(1)(a)	$ 1,553,019,488	Worksheet 1, line 1
24	Carrying Charge Factor (Lines 22/23)			14.77%	
	Adjustment to carrying charge factor to reflect removal of ADIT that is subject to normalization.				
25	Transmission Related ADIT Balance at 12/31/2015			435,186,977	Sheet 2, Line 1
26	Post-96 PTF Transmission Plant Allocation Factor			76.12%	Post 96 RNS Rev Rqmt worksheet 14, line 3
27	Transmission Related ADIT Balance - Post-96 PTF Total (line 25*26)			331,280,429	
28	Cost of Capital Rate (Line 33)			13.28%	line 33
29	Total Return and Income Taxes Associated with Post-96 PTF ADIT (Line 27*Line 28)			43,997,354	
30	Original Carrying Charge Factor (Line 24 above)			14.77%	
31	Incremental CCF Adjustment for Post-96 PTF ADIT (Line 29/Line 23)			2.83%	
32	New Carrying Charge Factor (Line 30 + Line 31)			17.61%	
	DERIVATION OF MPRP COST OF CAPITAL RATE (MCOC)				
33	Cost of Capital Rate - 11.07% ROE			13.28100%	Worksheet 2, line 9
34	Cost of Capital Rate - 1.25% bp ROE adder for MPRP			0.68248%	Worksheet 2, line 11. col C
35	MPRP Cost of Capital Rate (MCOC) (Lines 25 + 26)			13.96348%	

Company Name
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	-	
2	Transmission Plant Allocation Factor	-	
3	Transmission Related ADIT Balance at 12/31/2015	-	(Line 1 * Line 2) or Appropriate Reference
4	Transmission Related ADIT Balance at 12/31/2015	435,186,977	FF1 page 450.1 footnotes page 274, line 9, column k
5	Post-96 and Pre-97 PTF Plant Allocation Factors	81.25%	Sum of Pre-1997 and Post-1996 PTF Allocation Factors
6	PTF ADIT as of 12/31/2015	353,607,697	(Line 4*Line 5) or Appropriate Reference
7	Forecasted Transmission Related ADIT balance at 12/31/2016	437,061,988	Internal Records
8	Post-96 and Pre-97 PTF Plant Allocation Factors	81.25%	(Line 5)
9	Forecasted PTF ADIT 12/31/2016	355,131,222	(Line 7 * Line 8)
10	Change in ADIT 2015 to 2016	1,523,525	(Line 9 - Line 6)
11	Monthly Change in ADIT	126,960	(Line 10 /12 months)

	(A) Month	(B) Remaining Days	(C) = (B)/ Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT
12	Month 1	335	91.7808%	116,525
13	Month 2	307	84.1096%	106,786
14	Month 3	276	75.6164%	96,003
15	Month 4	246	67.3973%	85,568
16	Month 5	215	58.9041%	74,785
17	Month 6	185	50.6849%	64,350
18	Month 7	154	42.1918%	53,567
19	Month 8	123	33.6986%	42,784
20	Month 9	93	25.4795%	32,349
21	Month 10	62	16.9863%	21,566
22	Month 11	32	8.7671%	11,131
23	Month 12	1	0.2740%	348
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 705,761

ISO Tariff Billing
PTO Annual Transmission Revenue Requirements
per OATT Attachment F

Adjusted to Reflect ADIT Proration

Submitted on:	15 June 2016
Revenue Requirements for (year):	Calendar Year 2015
Customer:	Emera Maine (Bangor Hydro District Transmission)
Customer's NABs Number:	002
Name of Participant responsible for customer's billing:	Emera Maine (Bangor Hydro District Transmission)
DUNs number of Participant responsible for customer's billing:	006949002

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	$770,175	(a)	$51,129,890	(f)
Total of Attachment F - Section J - Support Revenue	$0	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$129,160	(c)	$0	(h)
Total of Attachment F - Section (L through O)	($19,141)	(d)	($1,256,881)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$880,193	(e)=(a)-(b)+(c)+(d)	$49,873,009	(j)
Forecasted Transmission Revenue Requirements includes ADIT Proration (per Attachment C to Attachment F Implementation Rule)	NA		($380,841)	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	$22,121	(l)	$1,519,217	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	$902,314	(n)=(e)+(l)	$51,011,385	(o)=(j)+(k)+(m)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements, and True-ups (including interest).			$51,913,700	(p) = (n) + (o)

Emera Maine - Bangor Hydro District
Post-96 RNS Revenue Requirements
Adjusted to Reflect ADIT Proration

Line No.	**FORECASTED TRANSMISSION REVENUE REQUIREMENTS (FTRR)**	**Forecast Period**	**Attachment F Reference Section:**	**Amount**	**Reference**
1	Forecasted Rev Req'ts for FTPA			$ (380,841)	line 10 below
2	Forecasted Rev Req'ts for FCWIP			-	line 9 below
3	Forecasted Transmission Revenue Requirements (Lines 1 + 2)			$ (380,841)	
4	Forecasted Transmission Plant Additions (FTPA)	2016	Appendix C iv	$ -	
5	Carrying Charge Factor (CCF)		Appendix C vi	17.11%	line 20 below
6	Subtotal Forecasted Rev Req'ts for FTPA (Lines 1*2)			-	
7	ADIT Adjustment - IRS Proration			2,730,438	Worksheet 10
8	Cost of Capital Rate			13.95%	Line 40 below
9	Revenue Requirement Associated with ADIT Adjustment (Line 7*Line 8)			380,841	
10	Total Forecasted Rev Req'ts for FTPA (Lines 6 - Line 9)			(380,841)	
11	Forcasted NRI CWIP (FCWIP)	2016	Appendix C v	$ -	Annual Report of Construction Costs
12	NRI Cost of Capital Rate		Appendix C vii	14.67%	line 42 below
13	Forecasted Rev Req'ts for FCWIP (Lines 11*12)			$ -	
	DERIVATION OF CARRYING CHARGE FACTOR (CCF)				
14	Investment Return and Income Taxes		(A)	$ 35,312,265	Worksheet(s) 1, line 14 Totals
15	Depreciation Expense		(B)	9,009,211	Worksheets 1, line 15
16	Amortization of Loss on Reacquired Debt		(C)	-	Worksheets 1, line 16
17	Amortization of Investment Tax Credits		(D)	(15,692)	Worksheets 1, line 17
18	Municipal Taxes		(E)	3,708,277	Worksheet 1, line 18
19	Payroll Taxes		(F)	101,572	Worksheet 1, line 19
20	Operation and Maintenance Expense		(G)	2,489,991	Worksheet 1, line 20
21	Administrative and General Expense		(H)	1,294,441	Worksheet 1, line 21
22	Transmission Related Integrated Facilities Charge		(I)	-	Worksheet 1, line 22
23	Transmission Support Revenue		(J)	-	Worksheet 1, line 23
24	Transmission Support Expense		(K)	129,160	Worksheet 1, line 24
25	Transmission Related Expense from Generators		(L)	-	Worksheet 1, line 25
26	Transmission Related Taxes and Fees Charge		(M)	-	Worksheet 1, line 26
27	Revenue for ST Trans. Service Under ISO Tariff		(N)	(755,687)	Worksheet 1, line 27
28	Transmission Rents Received from Electric Property		(O)	(520,336)	Worksheet 1, line 28
29	Total Expenses (Lines 14 thru 21)			50,753,202	
30	PTF Transmission Plant		(A)(1)(a)	$ 355,608,630	Worksheet 1, line 1
31	Carrying Charge Factor (Lines 22/23)			14.27%	
	Adjustment to carrying charge factor to reflect removal of ADIT that is subject to normalization.				
32	Transmission Related ADIT Balance at 12/31/2015			102,753,997	Sheet 2, Line 1
33	Post-96 PTF Transmission Plant Allocation Factor			70.52%	Worksheet 5, Line 3
34	Transmission Related ADIT Balance - Post-96 PTF Total (line 32*33)			72,463,762	
35	Cost of Capital Rate (Line 40)			13.95%	Appropriate Reference
36	Total Return and Income Taxes Associated with Post-96 PTF ADIT (Line 27*Line 28)			10,107,246	
37	Original Carrying Charge Factor (Line 31 above)			14.27%	
38	Incremental CCF Adjustment for Post-96 PTF ADIT (Line 36/Line 30)			2.84%	
39	New Carrying Charge Factor (Line 37 + Line 38)			17.11%	
	DERIVATION OF NRI COST OF CAPITAL RATE				
40	Cost of Capital Rate - 11.07% ROE			13.94800%	Worksheet 2, post 96
41	Cost of Capital Rate - 0.67% bp ROE adder for NRI			0.72600%	Worksheet 2, post 03 (NRI)
42	NRI Cost of Capital Rate (Lines 40 + 41)			14.67400%	

Emera Maine - Bangor Hydro District
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	160,276,747	Company Records
2	Transmission Plant Allocation Factor	54.36%	2016 BHD LNS Exhibit 6, line 47
3	Transmission Related ADIT Balance at 12/31/2015	87,127,291	(Line 1 * Line 2)
4	Transmission Related ADIT Balance at 12/31/2015	87,127,291	Line 3
5	Post-96 and Pre-97 PTF Plant Allocation Factors	71.60%	BHD RNS Worksheet(s) 5
6	PTF ADIT as of 12/31/2015	62,379,307	(Line 4*Line 5)
7	Forecasted Transmission Related ADIT balance at 12/31/2016	95,359,910	Company Records
8	Post-96 and Pre-97 PTF Plant Allocation Factors	71.60%	(Line 5)
9	Forecasted PTF ADIT 12/31/2016	68,273,499	(Line 7 * Line 8)
10	Change in ADIT 2015 to 2016	5,894,193	(Line 9 - Line 6)
11	Monthly Change in ADIT	491,183	(Line 10 /12 months)

	(A) Month	(B) Remaining Days	(C) = (B)/ Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT
12	Month 1	335	91.7808%	450,812
13	Month 2	307	84.1096%	413,132
14	Month 3	276	75.6164%	371,415
15	Month 4	246	67.3973%	331,044
16	Month 5	215	58.9041%	289,327
17	Month 6	185	50.6849%	248,956
18	Month 7	154	42.1918%	207,239
19	Month 8	123	33.6986%	165,522
20	Month 9	93	25.4795%	125,151
21	Month 10	62	16.9863%	83,434
22	Month 11	32	8.7671%	43,063
23	Month 12	1	0.2740%	1,346
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 2,730,438
25	Number of Days in the Year	365		

Eversource Energy Service Company
ISO New England Inc. Transmission markets and Services Tariff, Section II
Actual PTF Revenue Requirements per Attachment F of the ISO-NE OATT
Adjusted to Reflect ADIT Proration

Submitted on:	May 31, 2016
Revenue Requirements for (year):	Calendar Year 2015
Customer:	Eversource Energy Service Company
Customer's NABs Number:	# 34
Name of Participant responsible for customer's billing:	Eversource Transmission
DUNs number of Participant responsible for customer's billing:	# 05-254-3980

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	= 73,343,115	(a)	633,278,394	(g)
Total of Attachment F - Section J - Support Revenue	3,149,116	(b)	-	(h)
Total of Attachment F - Section K - Support Expense	2,910,297	(c)	-	(i)
Total of Attachment F - Section (L through O)	(7,168,474)	(d)	4,926,836	(j)
Sub Total - Sum (A through I) - J + K + (L through O)	65,935,822	(e)=(a)-(b)+(c)+(d)	638,205,230	(k)=(g)-(h)+(i)+(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A	(f)	80,206,714	(l)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	(4,228,366)	(m)	(18,199,472)	(n)
Forecasted Transmission Related Merger Cost Adjustment - Docket No. ER16-1023. See Exhibit No. ES-221, Schedule 1, Page 1 of 1.	N/A	(o)	6,938,000	(p)
Adjusted Sub Total (Sub Total + True-up)	61,707,456	(q) = (e)+(f)+(m)+(o)	707,150,472	(r) = (k)+(l)+(n)+(p)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post Revenue Requirements Subtotals, Forecasted Revenue Requirements, and True-ups (including interest)			768,857,928	(s) = (q) + (r)

Worksheet 1F

Eversource Energy Service Company
Forecasted Transmission Revenue Requirements of PTF Facilities - 2015 Estimated
ISO New England Inc. Transmission, Markets and Service Tariff, Section II
Actual PTF Revenue Requirements per Attachment F of the ISO-NE OATT
For Costs in 2015 at 11.07%
Adjusted to Reflect ADIT Proration

Line No.			Attachment F Reference	CL&P	PSNH	WMECO	Total NU	Reference
	I.	**FORECASTED TRANSMISSION REVENUE REQUIREMENTS**						
1		Forecasted Transmission Plant Additions (excl. Localized)	App. C	$ 293,526,784	$ 147,717,558	$ 67,540,782		Attachment G
2		Carrying Charge Factor (line 18)	App. C	16.50%	18.26%	17.59%		Line 29
3		**Forecasted Transmission Revenue Requirements** (Lines 1 * 2)		$ 48,443,000	$ 26,968,000	$ 11,881,000	$ 87,292,000	
4		Forecasted NEEWS CWIP		$ -		$ -		
5		NEEWS Cost of Capital Rate (line 28)		12.93%		12.60%		
6		**Forecasted Transmission Rev. Req. for CWIP** (Lines 4 * 5)		$ -		$ -		
7		ADIT Adjustment - IRS Proration		33,827,368	16,386,661	7,939,854		ADIT Proration Sheets 1, 2, 3. Line 24
8		Cost of Capital Rate		12.34%	11.95%	12.00%		W/S 2A, 2B, 2C
9		**Revenue Requirement Associated with ADIT Adjustment**		4,174,297	1,958,206	952,783		Line 7 * Line 8
10		**Total Forecasted Transmission Revenue Requirements**		$ 44,268,703	$ 25,009,794	$ 10,928,217	$ 80,206,714	Line 3 + 6 - 9
	II.	**CARRYING CHARGE FACTOR (Post 96) (*)**						
11		Investment Return and Income Taxes	(A)	$ 237,268,151	58,567,874	65,857,638	361,693,663	W/S 1B line 16
12		Depreciation Expense	(B)	65,596,406	14,427,472	14,842,994	94,866,872	W/S 1B line 17
13		Amortization of Loss on Reacquired Debt	(C)	427,704	198,567	41,130	667,401	W/S 1B line 18
14		Investment Tax Credit	(D)	(298,958)	(3,114)	(27,864)	(329,936)	W/S 1B line 19
15		Property Tax Expense	(E)	41,027,464	17,218,213	17,493,124	75,738,801	W/S 1B line 20
16		Payroll Tax Expense	(F)	207,381	77,535	(70,159)	214,757	W/S 1B line 21
17		Operation & Maintenance Expense	(G)	23,897,727	6,386,523	5,340,203	35,624,453	W/S 1B line 22
18		Administrative & General Expense	(H)	34,760,272	9,982,392	8,767,488	53,510,152	W/S 1B line 23
19		Total Expenses (Lines 8 thru 15)		$402,886,147	$106,855,462	$112,244,554	$621,986,163	
20		PTF Transmission Plant		$2,751,657,489	$676,116,503	$774,552,936	$4,202,326,928	W/S 1B line 1
21		Carrying Charge Factor (Lines 16/17)		14.64%	15.80%	14.49%	14.80%	
	III.	**Adjustment to carrying charge factor to reflect removal of ADIT that is subject to normalization.**						
22		Transmission Related ADIT Balance at 12/31/2015		523,936,888	172,814,135	241,669,618	938,420,641	ADIT Proration Sheet 2, Line 1
23		Post-96 PTF Transmission Plant Allocation Factor		79.3185%	80.4301%	82.8103%		Sheet 6, Line 3
24		Transmission Related ADIT Balance - Post-96 PTF Total		415,578,881	138,994,582	200,127,336	754,700,798	Line 22 * 23
25		Cost of Capital Rate (Line 33)		12.34%	11.95%	12.00%		Line 8
26		Total Return and Income Taxes Associated with Post-96 PTF ADIT		51,282,434	16,609,853	24,015,280	91,907,567	Line 24*Line 25
27		Original Carrying Charge Factor		14.64%	15.80%	14.49%		Line 21
28		Incremental CCF Adjustment for Post-96 PTF ADIT (Line 29/Line 23)		1.86%	2.46%	3.10%		Line 26 / Line 20
29		New Carrying Charge Factor (Line 30 + Line 31)		16.50%	18.26%	17.59%		Line 24 + Line 25
29		Cost of Capital Rate - 11.07% ROE		12.34%		12.00%		W/S 2A, 2C
30		Cost of Capital Rate - 0.67% bp ROE adder for NEEWS		0.59%		0.60%		W/S 2A, 2C
31		NEEWS Cost of Capital Rate		12.93%		12.60%		

(*) The Carrying Charge Factor shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A through II. H divided by PTF Transmission Plant.

Connecticut Light and Power Company (CL&P)
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)
ADIT Proration Sheet 1

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	-	
2	Transmission Plant Allocation Factor	-	
3	Transmission Related ADIT Balance at 12/31/2015	-	
4	Transmission Related ADIT Balance at 12/31/2015	523,936,888	FF1 page 274 ln. 9 footnote
5	Post-96 and Pre-97 PTF Plant Allocation Factors	89.5945%	Sheet 5, Line 3 + Sheet 6, Line 3
6	PTF ADIT as of 12/31/2015	469,418,635	(Line 4*Line 5)
7	Forecasted Transmission Related ADIT balance at 12/31/2016	605,440,888	Internal Records
8	Post-96 and Pre-97 PTF Plant Allocation Factors	89.5945%	(Line 5)
9	Forecasted PTF ADIT 12/31/2016	542,441,736	(Line 7 * Line 8)
10	Change in ADIT 2015 to 2016	73,023,101	(Line 9 - Line 6)
11	Monthly Change in ADIT	6,085,258	(Line 10 /12 months)

	(A) Month	(B) Remaining Days	(C) = (B)/ Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT
12	Month 1	335	91.7808%	5,585,100
13	Month 2	307	84.1096%	5,118,286
14	Month 3	276	75.6164%	4,601,456
15	Month 4	246	67.3973%	4,101,297
16	Month 5	215	58.9041%	3,584,467
17	Month 6	185	50.6849%	3,084,309
18	Month 7	154	42.1918%	2,567,479
19	Month 8	123	33.6986%	2,050,649
20	Month 9	93	25.4795%	1,550,491
21	Month 10	62	16.9863%	1,033,660
22	Month 11	32	8.7671%	533,502
23	Month 12	1	0.2740%	16,672
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 33,827,368
				To Summary, Line 7
25	Number of Days in the Year	365		

Public Service Company of New Hampshire (PSNH)
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)
ADIT Proration Sheet 2

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	-	
2	Transmission Plant Allocation Factor	-	
3	Transmission Related ADIT Balance at 12/31/2015	-	
4	Transmission Related ADIT Balance at 12/31/2015	172,814,135	FF1 page 274 ln. 9 footnote
5	Post-96 and Pre-97 PTF Plant Allocation Factors	90.9237%	Sheet 5, Line 3 + Sheet 6, Line 3
6	PTF ADIT as of 12/31/2015	157,129,006	(Line 4*Line 5)
7	Forecasted Transmission Related ADIT balance at 12/31/2016	211,719,135	Internal Records
8	Post-96 and Pre-97 PTF Plant Allocation Factors	90.9237%	(Line 5)
9	Forecasted PTF ADIT 12/31/2016	192,502,871	(Line 7 * Line 8)
10	Change in ADIT 2015 to 2016	35,373,865	(Line 9 - Line 6)
11	Monthly Change in ADIT	2,947,822	(Line 10 /12 months)

	(A) Month	(B) Remaining Days	(C) = (B)/ Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT
12	Month 1	335	91.7808%	2,705,535
13	Month 2	307	84.1096%	2,479,401
14	Month 3	276	75.6164%	2,229,038
15	Month 4	246	67.3973%	1,986,751
16	Month 5	215	58.9041%	1,736,388
17	Month 6	185	50.6849%	1,494,102
18	Month 7	154	42.1918%	1,243,739
19	Month 8	123	33.6986%	993,376
20	Month 9	93	25.4795%	751,089
21	Month 10	62	16.9863%	500,726
22	Month 11	32	8.7671%	258,439
23	Month 12	1	0.2740%	8,076
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 16,386,661
				To Summary, Line 7
25	Number of Days in the Year	365		

Western Massachusetts Electric Company (WMECO)
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)
ADIT Proration Sheet 3

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	-	
2	Transmission Plant Allocation Factor	-	
3	Transmission Related ADIT Balance at 12/31/2015	-	
4	Transmission Related ADIT Balance at 12/31/2015	241,669,618	FF1 page 274 ln. 9 footnote
5	Post-96 and Pre-97 PTF Plant Allocation Factors	88.1176%	Sheet 5, Line 3 + Sheet 6, Line 3
6	PTF ADIT as of 12/31/2015	212,953,467	(Line 4*Line 5)
7	Forecasted Transmission Related ADIT balance at 12/31/2016	261,120,618	Internal Records
8	Post-96 and Pre-97 PTF Plant Allocation Factors	88.1176%	(Line 5)
9	Forecasted PTF ADIT 12/31/2016	230,093,222	(Line 7 * Line 8)
10	Change in ADIT 2015 to 2016	17,139,754	(Line 9 - Line 6)
11	Monthly Change in ADIT	1,428,313	(Line 10 /12 months)

	(A) Month	(B) Remaining Days	(C) = (B)/ Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT
12	Month 1	335	91.7808%	1,310,917
13	Month 2	307	84.1096%	1,201,348
14	Month 3	276	75.6164%	1,080,039
15	Month 4	246	67.3973%	962,644
16	Month 5	215	58.9041%	841,335
17	Month 6	185	50.6849%	723,939
18	Month 7	154	42.1918%	602,631
19	Month 8	123	33.6986%	481,322
20	Month 9	93	25.4795%	363,926
21	Month 10	62	16.9863%	242,618
22	Month 11	32	8.7671%	125,222
23	Month 12	1	0.2740%	3,913
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 7,939,854
				To Summary, Line 7
25	Number of Days in the Year	365		

Sheet: Input Panel

EFFECTIVE JUNE 1, 2016
ISO New England Inc.
Annual Transmission Revenue Requirements
Per FERC Electric Tariff No. 3, Section II - Attachment F
Adjusted to Reflect ADIT Proration

Shading denotes an input

Submitted on:	15-May-16
Revenue Requirements for (year):	Calendar Year 2015
Customer:	Fitchburg Gas and Electric Light Company
Customer's NABs Number:	38
Name of Participant responsible for customer's billing:	Fitchburg Gas and Electric Light Company
DUNs number of Participant responsible for customer's billing:	006-954-4317

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I =	$212,303	(a)	$656,526	(f)
Total of Attachment F - Section J - Support Revenue	$0	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$36,589	(c)	$0	(h)
Total of Attachment F - Section (L through O)	$0	(d)	$0	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$248,892	(e)=(a)-(b)+(c)+(d)	$656,526	(j)=(f)-(g)+(h)+(i)
Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)	N/A		$172,509	(m) Worksheet 1a
Annual True-up (per Appendix C to Attachment F Implementation Rule)	$33,333	(k)	$111,099	(n) Worksheet 1c
Interest Charge on Annual True-up	$1,121	(l)	$3,736	(o) Worksheet 1c
Total	$283,347	(p) =(e)+(k)+(l)+(p)	$943,871	(q)=(j)+(m)+(n)+(o)+ (q)

Annual Revenue Requirements Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements & True-ups (including interest) — $1,227,218 (r) =(p)+(q)

Fitchburg Gas and Electric Light Company
Post-96 RNS Revenue Requirements
Adjusted to Reflect ADIT Proration

Line No.	FORECASTED TRANSMISSION REVENUE REQUIREMENTS (FTRR)	Forecast Period	Attachment F Reference Section:	Amount	Reference
1	Forecasted Rev Req'ts for FTPA			$ 172,509	line 10 below
2	Forecasted Rev Req'ts for FCWIP			-	
3	Forecasted Transmission Revenue Requirements (Lines 1 + 2)			$ 172,509	
4	Forecasted Transmission Plant Additions (FTPA)	2016	Appendix C iv	$ 904,638	Workpaper 1, page 8
5	Carrying Charge Factor (CCF)		Appendix C vi	19.27%	line 29 below
6	Subtotal Forecasted Rev Req'ts for FTPA (Lines 1*2)			174,291	
7	ADIT Adjustment - IRS Proration			13,512	Worksheet 1a.1, line 24
8	Cost of Capital Rate			13.18%	Worksheet 2
9	Revenue Requirement Associated with ADIT Adjustment (Line 7*Line 8)			1,781	
10	Total Forecasted Rev Req'ts for FTPA (Lines 6 - Line 9)			172,509	
	DERIVATION OF CARRYING CHARGE FACTOR (CCF)				
11	Investment Return and Income Taxes		(A)	$ 266,332	Worksheet 1, line 14
12	Depreciation Expense		(B)	145,744	Worksheet 1, line 15
13	Amortization of Loss on Reacquired Debt		(C)	-	Worksheet 1, line 16
14	Amortization of Investment Tax Credits		(D)	-	Worksheet 1, line 17
15	Municipal Taxes		(E)	46,383	Worksheet 1, line 18
16	Payroll Taxes		(F)	1,702	Worksheet 1, line 19
17	Operation and Maintenance Expense		(G)	114,373	Worksheet 1, line 20
18	Administrative and General Expense		(H)	81,994	Worksheet 1, line 21
19	Total Expenses (Lines 11 thru 18)			656,528	
20	PTF Transmission Plant		(A)(1)(a)	$ 3,813,149	Worksheet 5, line 1
21	Carrying Charge Factor (Lines 19/20)			17.22%	
	Adjustment to carrying charge factor to reflect removal of ADIT that is subject to normalization.				
22	Transmission Related ADIT Balance at 12/31/2015			1,961,867	Worksheet 1a.1, Line 4
23	Post-96 PTF Transmission Plant Allocation Factor			30.20%	Worksheet 5
24	Transmission Related ADIT Balance - Post-96 PTF Total (line 22*23)			592,580	
25	Cost of Capital Rate (Line 33)			13.18%	Worksheet 2
26	Total Return and Income Taxes Associated with Post-96 PTF ADIT (Line 24*Line 25)			78,126	
27	Original Carrying Charge Factor (Line 24 above)			17.22%	
28	Incremental CCF Adjustment for Post-96 PTF ADIT (Line 29/Line 23)			2.05%	
29	New Carrying Charge Factor (Line 27 + Line 28)			19.27%	

Fitchburg Gas and Electric Light Company
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	21,096,705	Workpaper 3
2	Transmission Plant Allocation Factor	9.2994%	Worksheet 5
3	Transmission Related ADIT Balance at 12/31/2015	1,961,867	(Line 1 * Line 2)
4	Transmission Related ADIT Balance at 12/31/2015	1,961,867	Line 3
5	Post-96 and Pre-97 PTF Plant Allocation Factors	39.94%	Worksheet 5
6	PTF ADIT as of 12/31/2015	783,660	(Line 4*Line 5)
7	Forecasted Transmission Related ADIT balance at 12/31/2016	2,034,889	Internal Records
8	Post-96 and Pre-97 PTF Plant Allocation Factors	39.94%	(Line 5)
9	Forecasted PTF ADIT 12/31/2016	812,828	(Line 7 * Line 8)
10	Change in ADIT 2015 to 2016	29,168	(Line 9 - Line 6)
11	Monthly Change in ADIT	2,431	(Line 10 /12 months)

	(A) Month	(B) Remaining Days	(C) = (B)/ Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT	
12	Month 1	335	91.7808%	2,231	
13	Month 2	307	84.1096%	2,044	
14	Month 3	276	75.6164%	1,838	
15	Month 4	246	67.3973%	1,638	
16	Month 5	215	58.9041%	1,432	
17	Month 6	185	50.6849%	1,232	
18	Month 7	154	42.1918%	1,026	
19	Month 8	123	33.6986%	819	
20	Month 9	93	25.4795%	619	
21	Month 10	62	16.9863%	413	
22	Month 11	32	8.7671%	213	
23	Month 12	1	0.2740%	7	
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 13,512	To Worksheet 1a, Line 7
25	Number of Days in the Yea	365			

ISO-NE Tariff Billing
PTO Annual Transmission Revenue Requirements
per OATT Attachment F
Adjusted to Reflect ADIT Proration

1	Submitted on:	June 14, 2016			
2	Revenue Requirements for (test year):	Calendar Year 2015			
3	Rates Effective for the period:	June 1, 2016			
4	through:	May 31, 2017			
5	Customer:	Maine Electric Power Company			
6	Customer's NABs Number:				
7	Name of Participant responsible for customer's billing:	Central Maine Power Company			
8	DUNs number of Participant responsible for customer's billing:	006948954			
		Pre-97 Revenue Requirements		**Post-96 Revenue Requirements**	
9	Total of Attachment F - Sections A through I	= $ 2,716,955	(a)	$ 3,839,162	(f)
10	Total of Attachment F - Section J - Support Revenue	-	(b)	-	(g)
11	Total of Attachment F - Section K - Support Expense	-	(c)	-	(h)
12	Total of Attachment F - Section (L through P)	(1,121,555)	(d)	(1,548,883)	(i)
13	Sub Total - Sum (A through I) - J + K + (L through P)	1,595,400	(e)=(a)-(b)+(c)+(d)	2,290,279	(j)
14	Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)			(942)	(k)
15	Annual True-up (per Appendix C to Attachment F Implementation Rule)	50,783	(l)	129,279	(m)
16	Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	**$ 1,646,182**	(n)=(e)+(l)	**$ 2,418,617**	(o)=(j)+(k)+(m)
17	Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements, and True-ups (including interest)		**$ 4,064,799**	(p) = (n)+(o)	

Maine Electric Power Company
Attachment F RNS Revenue Requirements
For the Test Year Ended December 31, 2015
Revenue Requirement associated with Forecasted Transmission Plant Additions
Adjusted to Reflect ADIT Proration

Line No.	FORECASTED TRANSMISSION REVENUE REQUIREMENTS (FTRR)	Forecast Period	Attachment F Reference Section:		Amount	Reference
1	Forecasted Rev Req'ts for FTPA			$	(942)	line 5 below
2	Forecasted Rev Req'ts for FCWIP				-	
3	Forecasted Transmission Revenue Requirements (Lines 1 + 2)			$	(942)	
4	Forecasted Transmission Plant Additions (FTPA)	2016	Appendix C iv	$	-	
5	Carrying Charge Factor (CCF)		Appendix C vi		15.10%	line 20 below
6	Forecasted Rev Req'ts for FTPA (Lines 1*2)			$	-	
7	ADIT Adjustment - IRS Proration			$	5,037	Worksheet 2_ADIT Proration
8	Cost of Capital Rate - 11.07% ROE				18.70%	Worksheet 2, line 9
9	Revenue Requirement Associated with ADIT Adjustment (Line 7*Line 8)				942	
10	Total Forecasted Revenue Requirements for FTPA (line 6- line 9)			$	(942)	
	DERIVATION OF CARRYING CHARGE FACTOR (CCF)					
11	Investment Return and Income Taxes		(A)	$	4,030,048	Worksheet 1, line 14
12	Depreciation Expense		(B)		486,302	Worksheet 1, line 15
13	Amortization of Loss on Reacquired Debt		(C)		-	Worksheet 1, line 16
14	Amortization of Investment Tax Credits		(D)		-	Worksheet 1, line 17
15	Municipal Taxes		(E)		897,479	Worksheet 1, line 18
16	Operation and Maintenance Expense		(G)		901,337	Worksheet 1, line 20
17	Administrative and General Expense		(H)		240,951	Worksheet 1, line 21
18	Total Expenses (Lines 10 thru 17)				6,556,117	
19	PTF Transmission Plant		(A)(1)(a)	$	48,906,242	Worksheet 1, line 1
20	Carrying Charge Factor (Lines 18/19)				13.41%	
	Adjustment to carrying charge factor to reflect removal of ADIT that is subject to normalization.					
21	ADIT - Account 282 Total				4,443,205	Worksheet 2_ADIT Proration
22	Post-96 PTF Transmission Plant Allocation Factor				100.00%	RNS Rev Rqmts worksheet 5, line 3
23	ADIT - Account 282, Post-96 Total (line 21*22)				4,443,205	
24	Cost of Capital (Line 8)				18.70%	
25	Total Return Associated with ADIT (Line 23*Line 24)				830,883	
26	Original Carrying Charge Factor (Line 20 above)				13.41%	
27	Incremental CCF Adjustment for ADIT (Line 25/Line 19)				1.70%	
28	New Carrying Charge Factor (Line 26 + Line 27)				15.10%	

Maine Electric Power Company
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	-	
2	Transmission Plant Allocation Factor	-	
3	Transmission Related ADIT Balance at 12/31/2015	-	(Line 1 * Line 2) or Appropriate Reference
4	Transmission Related ADIT Balance at 12/31/2015	4,443,205	FF1 page 274, line 9, column k
5	Post-96 and Pre-97 PTF Plant Allocation Factors	100.00%	Sum of Pre-1997 and Post-1996 PTF Allocation Factors
6	PTF ADIT as of 12/31/2015	4,443,205	(Line 4*Line 5) or Appropriate Reference
7	Forecasted Transmission Related ADIT balance at 12/31/2016	4,432,332	Internal Records
8	Post-96 and Pre-97 PTF Plant Allocation Factors	100.00%	(Line 5)
9	Forecasted PTF ADIT 12/31/2016	4,432,332	(Line 7 * Line 8)
10	Change in ADIT 2015 to 2016	(10,873)	(Line 9 - Line 6)
11	Monthly Change in ADIT	(906)	(Line 10 /12 months)

	(A) Month	(B) Remaining Days	(C) = (B)/ Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT
12	Month 1	335	91.7808%	(832)
13	Month 2	307	84.1096%	(762)
14	Month 3	276	75.6164%	(685)
15	Month 4	246	67.3973%	(611)
16	Month 5	215	58.9041%	(534)
17	Month 6	185	50.6849%	(459)
18	Month 7	154	42.1918%	(382)
19	Month 8	123	33.6986%	(305)
20	Month 9	93	25.4795%	(231)
21	Month 10	62	16.9863%	(154)
22	Month 11	32	8.7671%	(79)
23	Month 12	1	0.2740%	(2)
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ (5,037)

Sheet: Input Panel

ISO Tariff Billing
ISO Annual Transmission Revenue Requirements
per Tariff Attachment F and ISO Agreement Part 2, Section 6.3
Adjusted to Reflect ADIT Proration

Shading denotes an input

Submitted on:	
Revenue Requirements for (year):	Calendar Year 2015
Rates Effective for the Period:	June 2016
Through:	May 2017
Customer:	New England Power Company
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	
DUNs number of Participant responsible for customer's billing:	

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	$170,034,809	(a)	$214,272,102	(f)
Total of Attachment F - Section J - Support Revenue	$4,933,216	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$662,286	(c)	$0	(h)
Total of Attachment F - Section (L through O)	($314,956)	(d)	($1,329,682)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$165,448,923	(e)=(a)-(b)+(c)+(d)	$212,942,420	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A		$32,528,464	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	13,034,801	(l)	(6,056,490)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	$178,483,724	(n)=(e)+(l)	$239,414,394	(o)=(j)+(k)+(m)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements and True-ups (including interest)			$417,898,117	(p) = (n) + (o)

New England Power Company
Post 1996 Regional Network Service Revenue Requirement
For Test Year Ended 12/31/2015
Adjusted to Reflect ADIT Proration

Shading denotes an input

Line No.	Description	Attachment F Reference		Forecasted Amount $	Reference
1	Forecasted Revenue Requirements for Forecasted Transmission Plant Additions (FTPA)		$	32,528,464	Line 10
2	Forecasted Revenue Requirements for Forecasted Transmission CWIP		$	-	Line 13
3	***Forecasted Transmission Revenue Requirements***		**$**	**32,528,464**	Line 1 + Line 2
4	Forecasted Transmission Plant Additions (FTPA)	Appendix C iv	$	186,679,448	Project Detail
5	Carrying Charge Factor (CCF)	Appendix C vi		18.17546%	Line 32
6	***Subtotal Forecasted Revenue Requirements for FTPA***		**$**	**33,929,845**	Line 4 * Line 5
7	ADIT Adjustment - IRS Proration		$	11,604,925	ADIT Proration Line 24
8	Cost of Capital Rate			12.07574%	Worksheet 2, Cap Structure 11.07%
9	***Revenue Requirement Associated with ADIT Adjustment***		**$**	**1,401,381**	Line 7 * Line 8
10	***Total Forecasted Rev Req'ts for FTP***		**$**	**32,528,464**	Line 6 - Line 9
11	Forecasted New England Power Company (NEP) NEEWS CWIP (FNCWIP)	Appendix C xiii	$	-	Project Detail
12	NEEWS NEP Cost of Capital Rate (NCOC)	Appendix C xiv		12.78712%	Worksheet 2, Cap Structure 11.74%
13	***Forecasted Revenue Requirements for FNCWIP***		**$**	**-**	Line 11 * Line 12

Derivation of Carrying Charge (CCF)

Line No.	Description	Attachment F Reference	Forecasted Amount $	Reference
14	Investment Return and Income Taxes	(A)	$100,188,447	Worksheet 2, excluding NEEWS CWIP
15	Depreciation Expense	(B)	29,710,245	Summary, Line 16
16	Amortization of Loss on Reacquired Debt	(C)	54,038	Summary, Line 17
17	Investment Tax Credit	(D)	(225,688)	Summary, Line 18
18	Property Tax Expense	(E)	23,201,716	Summary, Line 19
19	Payroll Tax Expense	(F)	1,179,665	Summary, Line 20
20	Operation & Maintenance Expense	(G)	28,480,943	Summary, Line 21
21	Administrative & General Expense	(H)	30,067,563	Summary, Line 22
22	Total Expenses		$212,656,930	Lines 14 through Line 21
23	PTF Transmission Plant	(A)(1)(a)	$1,376,440,296	Summary, Line 1
24	***Carrying Charge Factor (CCF)***		**15.44978%**	Line 22 / Line 23

Adjustment to carrying charge factor to reflect removal of ADIT that is subject to normalization.

Line No.	Description	Forecasted Amount $	Reference
25	Transmission Related ADIT Balance at 12/31/2015	513,852,640	ADIT Proration Line 4
26	Post-96 PTF Transmission Plant Allocation Factor	60.46170%	Worksheet 5 Line 3
27	Transmission Related ADIT Balance - Post-96 PTF Total	310,684,041	Line 25 * Line 26
28	Cost of Capital Rate	12.07574%	Line 8
29	Total Return and Income Taxes Associated with Post-96 PTF ADIT	37,517,397	Line 27 * Line 28
30	Original Carrying Charge Factor (CCF)	15.44978%	Line 24
31	Incremental CCF Adjustment for Post-96 PTF ADIT	2.72568%	Line 29 / Line 23
32	Carrying Charge Factor	18.17546%	Line 30 + Line 31

New England Power Company
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	518,157,492	Worksheet 3 Row 9 + 10
2	Transmission Plant Allocation Factor	99.17%	Worksheet 5 Row 16
3	Transmission Related ADIT Balance at 12/31/2015	513,852,640	Line 1 * Line 2
4	Transmission Related ADIT Balance at 12/31/2015	513,852,640	Line 3
5	Post-96 PTF Plant Allocation Factor	60.46%	Worksheet 5 Line 3
6	PTF ADIT as of 12/31/2015	310,684,041	Line 4 * Line 5
7	Forecasted Transmission Related ADIT balance at 12/31/2016	555,286,373	Internal Records
8	Post-96 PTF Plant Allocation Factor	60.46%	Line 5
9	Forecasted PTF ADIT 12/31/2016	335,735,581	Line 7 * Line 8
10	Change in ADIT 2015 to 2016	25,051,539	Line 9 - Line 6
11	Monthly Change in ADIT	2,087,628	Line 10 / 12 Months

	(A) Month	(B) Remaining Days	25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT	
12	Month 1	335	91.7808%	1,916,042	
13	Month 2	307	84.1096%	1,755,896	
14	Month 3	276	75.6164%	1,578,590	
15	Month 4	246	67.3973%	1,407,004	
16	Month 5	215	58.9041%	1,229,699	
17	Month 6	185	50.6849%	1,058,113	
18	Month 7	154	42.1918%	880,808	
19	Month 8	123	33.6986%	703,502	
20	Month 9	93	25.4795%	531,916	
21	Month 10	62	16.9863%	354,611	
22	Month 11	32	8.7671%	183,025	
23	Month 12	1	0.2740%	5,720	
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 11,604,925	To Worksheet 1, Line 7
25	Number of Days in the Year	365			

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
Base ROE set at 10.57% per Orders 531 and 531-A
For RNS Rates Effective June 1, 2016 through May 31, 2017
Adjusted to Reflect ADIT Proration

Revenue Requirements for Test Year:	2015
Customer:	NHT
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	NHT
DUNs number of Participant responsible for customer's billing:	

	Line No.	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	1	2,737,323	Pre-97 WS1, ln 14-22	9,401,879	Post-96 WS1, ln 14-22
Total of Attachment F - Section J - Support Revenue	2	0	Pre-97 WS1, ln 23	0	Post-96 WS1, ln 23
				0	
Total of Attachment F - Section K - Support Expense	3	668,217	Pre-97 WS1, ln 24	0	Post-96 WS1, ln 24
Total of Attachment F - Section (L through O)	4	(420)	Pre-97 WS1, ln 27	(1,159)	Post-96 WS1, ln 27
Sub Total - Sum (A through I) - J + K + (L through O)	5	3,405,121	Sum of above	9,400,720	Sum of above
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	6	N/A		$706,436	Post-96 WS8a, ln. 7
Annual True-up (per Attachment C to Attachment F Implementation Rule)	7	$ (405,876)	TU WS4, line 16	$ (1,094,782)	TU WS4, line 16
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	8	$ 2,999,244	lns. 5+6+7	$9,012,375	lns. 5+6+7
Less Amounts Refunded per Settlement Agreement Pending FERC approval in Docket No. ER15-85	9	$0		($6,500,000)	
	10	$ 2,999,244		$ 2,512,375	
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements, , True-ups (including interest) and Refund			**$ 5,511,619**	Sum of lines 8 Pre-97 & Post-96 above	

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
Base ROE set at 10.57% per Orders 531 and 531-A
Forecast Transmission Revenue Requirements of PTF Facilities
Adjusted to Reflect ADIT Proration

Shading denotes an input

Line No.	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Period	Attachment F Reference Section:	NHT	Reference
1	Forecasted Transmission Plant Additions	2015	Appendix C	$3,350,000	Note 1
2	Carrying Charge Factor		Appendix C	22.39%	Line 27
3	Total Forecasted Revenue Requirements (Lines 1*2)			$749,960	Line 1 x Line 2
4	ADIT Adjustment - IRS Proration			321,684	Post-96 WS 8b, Line 24
5	Cost of Capital Rate - 11.07% ROE			13.5300%	Post-96 WS 2
6	Revenue Requirement Associated with ADIT Adjustment (Line 7*Line 8)			43,524	
7	**Total Forecasted Rev Req'ts for FTPA (Lines 6 - Line 9)**			**706,436**	
	II. CARRYING CHARGE FACTOR				
8	Investment Return and Income Taxes (Post-'96 / Pre-'04 Investments)		II(A)	$4,474,291	Post-96, WS 1, line 14
9	Incentive Investment Return and Income Taxes (Eligible Investments)			0	Post-96, WS 1, line 15
10	Depreciation Expense		II(B)	1,440,111	Post-96, WS 1, line 16
11	Amortization of Loss on Reacquired Debt		II(C)	0	Post-96, WS 1, line 17
12	Investment Tax Credit		II(D)	0	Post-96, WS 1, line 18
13	Property Tax Expense		II(E)	759,640	Post-96, WS 1, line 19
14	Payroll Tax Expense		II(F)	10,329	Post-96, WS 1, line 20
15	Operation & Maintenance Expense		II(G)	1,225,552	Post-96, WS 1, line 21
16	Administrative & General Expense		II(H)	1,491,956	Post-96, WS 1, line 22
17	Total Expenses (Lines 4 thru 12)			$9,401,879	
18	PTF Transmission Plant		II(A)(1)(a)	$47,809,636	Post-96, WS 1, line 4
19	Carrying Charge Factor (Lines 13/14)			19.67%	
	Adjustment to carrying charge factor to reflect removal of ADIT that is subject to normalization.				
20	ADIT - Account 282, Total			13,100,270	Data Support 6, Line 3
21	Post-96 PTF Transmission Plant Allocation Factor			0.7341	Post-96 WS 5, Line 24
22	ADIT - Account 282, Post-'96 Total (line 20 x line 21)			9,617,153	
23	Cost of Capital			13.5300%	Post-96 WS 2, row 44
24	Total Return and Income Taxes Associated with Post-96 PTF ADIT (Line 22*Line 23)			1,301,199	
25	Original Carrying Charge Factor (Line 19 above)			19.67%	
26	Incremental CCF Adjustment for ADIT (Line 24/Line 18)			2.72%	
27	New Carrying Charge Factor (Line 25 + Line 26)			22.39%	

Note 1:

Forecast Plant Addition includes following projects expected to be placed in service / closed to books by 12/31/16:

1	Bus 2 Upgrade	$ 2,450,000
2	CIP Security Version 5	500,000
3	363 Line CCVT Replacements	400,000
	Total Forecast Capital Additions	$ 3,350,000

New Hampshire Transmission, LLC
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	-	NA
2	Transmission Plant Allocation Factor	-	NA
3	Transmission Related ADIT Balance at 12/31/2015	-	(Line 1 * Line 2)
4	Transmission Related ADIT Balance at 12/31/2015	13,100,270	Data Support 6, Line 3
5	Post-96 and Pre-97 PTF Plant Allocation Factors	NA	Direct Assigned - See Data Support 5
6	PTF ADIT as of 12/31/2015	13,100,270	(Line 4*Line 5)
7	Forecasted Transmission Related ADIT balance at 12/31/2016	13,794,689	Data Support 6, Line 18
8	Post-96 and Pre-97 PTF Plant Allocation Factors	NA	Direct Assigned - See Data Support 5
9	Forecasted PTF ADIT 12/31/2016	13,794,689	(Line 7 * Line 8)
10	Change in ADIT 2015 to 2016	694,418	(Line 9 - Line 6)
11	Monthly Change in ADIT	57,868	(Line 10 /12 months)

	(A) Month	(B) Remaining Days	(C) = (B)/ Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT
12	Month 1	335	91.7808%	53,112
13	Month 2	307	84.1096%	48,673
14	Month 3	276	75.6164%	43,758
15	Month 4	246	67.3973%	39,002
16	Month 5	215	58.9041%	34,087
17	Month 6	185	50.6849%	29,330
18	Month 7	154	42.1918%	24,416
19	Month 8	123	33.6986%	19,501
20	Month 9	93	25.4795%	14,745
21	Month 10	62	16.9863%	9,830
22	Month 11	32	8.7671%	5,073
23	Month 12	1	0.2740%	159
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 321,684
25	Number of Days in the Year	365		

NHT
Analysis of deferreds as of 12/31/2015

					Amounts Applicable in Rates			
			12/31/2015			Per NHT Accounting Category %		
	FERC 282							
	PTF		(13,100,110)		(13,100,110)	92.04%		
	NPTF		(796,645)		(796,645)	5.60%		
	Amounts Excluded		(335,724)		(335,724)	2.36%		
	Total Deferred acccount 282	$	(14,232,479)		**(14,232,479)**	100.00%	Ties to Form 1	
	FERC 283						Per NHT Accounting Records	
REG 101	FAS109 Increment to Reg Asset - BS only	$	(123,849)		(123,849)	Categorized	Category %	
PPD101	Prepaid Insurance		(12,038)		(12,038)	(132,251)	92.04%	PTF
PPD201	Prepaid Other		(20,290)		(20,290)	(8,042)	5.60%	NPTF
Regulatory assets/liabilities	Regulatory assets/liabilities		-		-	(3,389)	2.36%	Amounts Excluded
RES136	Other Accrued Liabilities and other		12,494		12,494	**(143,683)**	100.00%	
	Rounding				-			
	Total Deferred acccount 283	**$**	**(143,683)**		(143,683)		Ties to Form 1	
	FERC 190							
Regulatory assets/liabilities	Regulatory assets/liabilities		3,330,479		3,330,479		Category %	
PPD101	Prepaid Insurance					3,065,498	92.04%	PTF
	Net operating loss		-		-	186,419	5.60%	NPTF
						78,561	2.36%	Amounts Excluded
	Total deferred	**$**	**(11,045,683)**	**$**	**(11,045,683)**	**3,330,479**	100.00%	

	Net Total Categorized
PTF	(10,166,863)
NPTF	(618,268)
Amounts Excluded	(260,552)
Total in Rates	**(11,045,683)**

NHT Analysis of Forecast Deferred Taxes

Line		Total	Federal	State	Source Reference
1	FERC 282 ADITs as of 12/31/2015	14,232,653	12,419,174	1,813,479	
2	PTF Factor	92.04%	92.04%	92.04%	From Data Support 5 Worksheet
3	PTF FERC 282 ADITs as of 12/31/2015	13,100,270	11,431,076	1,669,194	
	Forecasted 2016 Book Depreciation				
4	Gross Book PPE excluding AFUDC equity 12/31/2015	73,062,400	73,062,400	73,062,400	
5	Forecasted 2016 Additions (1)	3,350,000	3,350,000	3,350,000	
6	Gross Book PPE as Adjusted 12/31/2016	76,412,400	76,412,400	76,412,400	
7	Book depreciation Rate	3.12%	3.12%	3.12%	
8	Forecasted 2016 Book Depreciation	2,384,067	2,384,067	2,384,067	
	Forecasted 2016 Tax Depreciation		Federal	State	
9	Total Forecasted Tax Depreciation pre-2016 Additions		2,613,018	3,279,886	PowerTax Report No. 16
	Tax Depreciation on Forecasted 2016 Additions				
10	Bonus Depreciation		1,675,000		
11	Other Depreciation - 2016 Additions		83,750	167,500	
12	Total Forecasted Tax Depreciation 2016		4,371,768	3,447,386	
13	Depreciation Difference Books vs Tax		1,987,701	1,063,319	
14	Effective Tax Rate		0.35	0.05525	
15	Change in FERC 282 ADITs in 2016	754,444	695,695	58,748	
16	Forecasted FERC 282 ADITs 12/31/2016	14,987,097			
17	PTF Factor	92.04%			
18	PTF FERC 282 ADITs as of 12/31/2015	13,794,689			

Notes:

(1) Assumption is that 2016 additions are placed in January

NSTAR Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Actual PTF Revenue Requirements per Attachment F of the ISO-NE OATT
For Costs in 2015
Adjusted to Reflect ADIT Proration

Submitted on:	May 31, 2016
Revenue Requirements for (year):	Calendar Year 2015
Customer:	NSTAR Electric Company
Customer's NABs Number:	# 3
Name of Participant responsible for customer's billing:	NSTAR Electric Company
DUNs number of Participant responsible for customer's billing:	# 00-695-1552

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	51,077,145	(a)	176,240,909	(f)
Total of Attachment F - Section J - Support Revenue		1,092,103	(b)	-	(g)
Total of Attachment F - Section K - Support Expense		1,120,182	(c)	-	(h)
Total of Attachment F - Section L through O		(3,038,352)	(d)	16,554	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		$ 48,066,872	(e)=(a)-(b)+(c)+(d)	$ 176,257,463	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		-	n/a	31,872,531	(k)
Annual True-up		(3,567,336)	(l)	(9,693,281)	(m)
Forecasted Transmission Related Merger Cost Adjustment - Docket No. ER16-1023. See Exhibit No. ES-222, Schedule 1, Page 1 of 1.		-	n/a	2,318,000	(n)
Total		44,499,536	(o)=(e)+(l)	200,754,713	(p)=(j)+(k)+(m)+(n)
Annual Projected Revenue Requirement Total = Sum of Pre-97 Revenue Requirements, plus Post-96 Revenue Requirements, plus Annual True-up, and plus Interest on Annual True-up:				$ 245,254,249	(r) = (p)+(q)

NSTAR Electric Company
ISO New England Inc Transmission, Markets and Services Tariff, Section II
Actual PTF Revenue Requirements per Attachment F of the ISO-NE OATT
For Costs in 2015
Adjusted to Reflect ADIT Proration

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Pre 1997	Post 1996	Reference
1	Transmission Plant	II (A)(1)(a)	$ 392,367,697	$ 1,328,239,304	Sheet 4, line 1
2	General Plant	II (A)(1)(b)	3,389,048	11,472,558	Sheet 4, line 2
3	Intangible Plant	II (A)(1)(b)	629,423	2,130,714	Sheet 4, line 3
4	Plant Held For Future Use	II (A)(1)(c)	-	16,174,891	Sheet 4, line 5
5	Total Plant (Line 1 + 2 + 3 + 4)		$ 396,386,168	$ 1,358,017,467	
6	Accumulated Depreciation	II (A)(1)(d)	(91,247,007)	(308,888,059)	Sheet 4, line 10
7	Accumulated Deferred Income Taxes	II (A)(1)(e)	(75,940,372)	(257,072,262)	Sheet 4, line 14
8	Loss On Reacquired Debt	II (A)(1)(f)	678,015	2,295,208	Sheet 4, line 15
9	Other Regulatory Assets	II (A)(1)(g)	4,746,421	16,067,516	Sheet 4, line 19
10	Net Investment (Line 5 + 6 + 7 + 8 + 9)		$ 234,623,225	$ 810,419,870	
11	Prepayments	II (A)(1)(h)	48,177	163,088	Sheet 4, line 20
12	Materials & Supplies	II (A)(1)(I)	1,547,294	5,237,879	Sheet 4, line 21
13	Cash Working Capital	II (A)(1)(j)	867,069	2,923,310	Sheet 4, line 27
14	Total Investment Base (Line 10 + 11 + 12 + 13)		$ 237,085,765	$ 818,744,147	
	II. REVENUE REQUIREMENTS				
15	Investment Return and Income Taxes	II (A)	$ 28,713,457	$ 100,535,669	Sheet 3, Line 26
16	Depreciation Expense	II (B)	8,538,379	28,904,000	Sheet 5, Line 4
17	Amortization of Loss on Reacquired Debt	II (C)	33,551	113,577	Sheet 5, Line 5
18	Investment Tax Credit	II (D)	(71,489)	(242,003)	Sheet 5, Line 6
19	Property Taxes	II (E)	6,802,127	23,026,462	Sheet 5, Line 7
20	Payroll Tax Expense	II (F)	152,643	516,725	Sheet 5, Line 22
21	Operation & Maintenance Expense	II (G)	3,948,435	13,366,186	Sheet 5, Line 11
22	Administrative & General Expense	II (H)	2,960,042	10,020,293	Sheet 5, Line 20
23	Transmission Related Integrated Facilities Charge	II (I)	-	-	
24	Transmission Support Revenue	II (J)	(1,092,103)	-	Sheet 7, Line 8
25	Transmission Support Expense	II (K)	1,120,182	-	Sheet 7, Line 8
26	Transmission Related Expense from Generators	II (L)	-	-	
27	Transmission Related Taxes and Fees Charge	II (M)	54,390	184,119	Sheet 5, Line 21
28	Revenue for ST Trans. Service Under NEPOOL Tariff	II (N)	(49,488)	(167,565)	OATT Schedule 8 TOUT
29	Transmission Rents Received from Electric Property	II (O)	(3,043,254)	-	
30	Total Revenue Requirements (Sum of Lines 15 through 29)		$ 48,066,872	$ 176,257,463	

III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT

Line No.	Description	Amount	Reference
31	Carrying Charge Factor Base Revenue Requirement Numerator	$ 176,240,909	Line 30 - Line 27 - Line 28
32	Less Post-2003 Enhanced Return Addition to Revenue Requirement	$ 1,374,290	Sheet 3, Line 25
33	Total Post-96 PTF Revenue Requirement	$ 174,866,619	Line 31 - 32
34	Post-96 PTF Transmission Plant in Service	$ 1,328,239,304	Line 1
35	Post-96 Carrying Charge Factor	13.17%	Line 33 / Line 34
	Adjustment to carrying charge factor to reflect removal of ADIT that is subject to normalization.		
36	Transmission Related ADIT Balance at 12/31/2015	366,398,733	ADIT Proration Sheet, Line 4
37	Post-96 PTF Transmission Plant Allocation Factor	63.1503%	Sheet 6, Line 3(C)
38	Transmission Related ADIT Balance - Post-96 PTF Total	231,381,899	Line 36 * 37
39	Cost of Capital Rate	12.11%	Sheet 3, Line 15(C)
40	Total Return and Income Taxes Associated with Post-96 PTF ADIT	28,023,587	Line 38 * 39
41	Original Carrying Charge Factor	13.17%	Line 35
42	Incremental CCF Adjustment for Post-96 PTF ADIT	2.11%	Line 40 / 34
43	New Carrying Charge Factor	15.28%	Line 41 + 42
44	Forecasted Post-96 PTF Plant Additions	$ 218,540,029	Attachment A
45	Post-96 Estimated Incremental Revenue Requirement	$ 33,392,544	Line 43 * 44
46	ADIT Adjustment - IRS Proration	12,550,267	ADIT Proration Sheet, Line 24
47	Cost of Capital Rate	12.11%	Line 39
48	Revenue Requirement Associated with ADIT Adjustment	1,520,013	Line 46 * 47
49	Total Forecasted Rev Req'ts for FTPA	31,872,531	Line 45 - 48

NSTAR Electric Company
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)
ADIT Proration Sheet 1

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	1,235,875,363	FF1 275.9(k) - 275.4(k)
2	Transmission Plant Allocation Factor	29.6469%	Sheet 6, Line 19(B)
3	Transmission Related ADIT Balance at 12/31/2015	366,398,733	Line 1 * Line 2
4	Transmission Related ADIT Balance at 12/31/2015	366,398,733	Line 3
5	Post-96 and Pre-97 PTF Plant Allocation Factors	81.8052%	Sheet 6, Line 4(C)
6	PTF ADIT as of 12/31/2015	299,733,216.32	Line 4*Line 5
7	Forecasted Transmission Related ADIT balance at 12/31/2016	399,516,733	Internal Records
8	Post-96 and Pre-97 PTF Plant Allocation Factors	81.8052%	Line 5
9	Forecasted PTF ADIT 12/31/2016	326,825,462	Line 7 * Line 8
10	Change in ADIT 2015 to 2016	27,092,246	Line 9 - Line 6
11	Monthly Change in ADIT	2,257,687	Line 10 /12 months

	(A) Month	(B) Remaining Days	(C) = (B)/Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT
12	Month 1	335	91.7808%	2,072,124
13	Month 2	307	84.1096%	1,898,931
14	Month 3	276	75.6164%	1,707,183
15	Month 4	246	67.3973%	1,521,619
16	Month 5	215	58.9041%	1,329,871
17	Month 6	185	50.6849%	1,144,307
18	Month 7	154	42.1918%	952,558
19	Month 8	123	33.6986%	760,810
20	Month 9	93	25.4795%	575,246
21	Month 10	62	16.9863%	383,498
22	Month 11	32	8.7671%	197,934
23	Month 12	1	0.2740%	6,185
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 12,550,267
				To Summary, Line 46
25	Number of Days in the Year	365		

The United Illuminating Company

Sheet: Input Panel Input Panel

Regional Network Service

Annual Transmission Revenue Requirements

per Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Adjusted to Reflect ADIT Proration

Shading denotes an input

Submitted on:	5/12/2016
Revenue Requirements for (year):	2015
Rate Period	6/1/2016 - 5/31/2017
Customer:	The United Illuminating Company
Customer's NABs Number:	51
Name of Participant responsible for customer's billing:	The United Illuminating Company
DUNs number of Participant responsible for customer's billing:	00-691-7967

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	21,234,315	(a)	113,521,945	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		480,120	(c)	0	(h)
Total of Attachment F - Section L through O		(130,712)	(d)	0	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		21,583,723	(e)=(a)-(b)+(c)+(d)	113,521,945	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		0	n/a	13,559,948	(m)
Annual True-up		(420,428)	(k)	301,630	(n)
Interest Charge on Annual True-up		(14,140)	(l)	10,144	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)		21,149,155	(p)	127,393,667	(q)
Annual Projected 2015 Revenue Requirement Total = Sum of Pre-97 Revenue Requirements, plus Post-96 Revenue Requirements, plus Annual True-up, and plus Interest on Annual True-up:				148,542,822	(r) = (p)+(q)

The United Illuminating Company
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	$ 335,625,605	Workpaper 1
2	Transmission Plant Allocation Factor	32.4538%	Worksheet 5 Line 16
3	Transmission Related ADIT Balance at 12/31/2015	108,923,263	(Line 1 * Line 2)
4	Transmission Related ADIT Balance at 12/31/2015	108,923,263	Line 3
5	Post-96 and Pre-97 PTF Plant Allocation Factors	90.3886%	Worksheet 5 Line 3
6	PTF ADIT as of 12/31/2015	98,454,212	(Line 4*Line 5)
7	Forecasted Transmission Related ADIT balance at 12/31/2016	123,695,000	Internal Records
8	Post-96 and Pre-97 PTF Plant Allocation Factors	90.3886%	(Line 5)
9	Forecasted PTF ADIT 12/31/2016	111,806,179	(Line 7 * Line 8)
10	Change in ADIT 2015 to 2016	13,351,967	(Line 9 - Line 6)
11	Monthly Change in ADIT	$ 1,112,664	(Line 10 /12 months)

	(A) Month	(B) Remaining Days	(C) = (B)/ Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT
12	Month 1	335	91.7808%	$ 1,021,212
13	Month 2	307	84.1096%	935,857
14	Month 3	276	75.6164%	841,357
15	Month 4	246	67.3973%	749,905
16	Month 5	215	58.9041%	655,405
17	Month 6	185	50.6849%	563,953
18	Month 7	154	42.1918%	469,453
19	Month 8	123	33.6986%	374,952
20	Month 9	93	25.4795%	283,501
21	Month 10	62	16.9863%	189,000
22	Month 11	32	8.7671%	97,549
23	Month 12	1	0.2740%	3,048
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 6,185,192

The United Illuminating Company 2016 Forecasted Plant in Service and PTF Transmission Revenue Requirements
(in thousands)
Adjusted to Reflect ADIT Proration

Line No.	Project Name	RSP ID	Est ISD	(A) Estimated PTF Plant In-Service (in thousands)	(B) Annual Carrying Charge	(C)=(A)x(B) Forecasted PTF Revenue Requirement (in thousands)	(D) 2015 12CP RNS Load	(E)=(C) / (D) RNS Rate Impact $/kw-yr
1	Milvon to Devon Tie 88005A - 89005B 115 kV Line Upgrade	1380	Dec-16	$ 30,900,000				
2	Hawthorne 115 kV Capacitor Bank Addition	1389	Feb-16	$ 8,300,000				
3	Baird-Devon A - Drilled Pier - 88006A	N/A	Apr-16	$ 2,600,000				
4	Baird-Devon B - Drilled Pier - 89006B	N/A	Apr-16	$ 2,900,000				
5	Milvon-Woodmont A - Drilled Pier - 88005A	N/A	Apr-16	$ 1,200,000				
6	Milvon-Woodmont B - Drilled Pier - 89005B	N/A	Apr-16	$ 2,800,000				
7	Woodmont - Allings Crossing A - Drilled Pier - 8804A	N/A	Apr-16	$ 4,100,000				
8	Woodmont - Allings Crossing B - Drilled Pier - 8904B	N/A	Apr-16	$ 1,400,000				
9	Allings Crossing - Elm West A - Drilled Piers - 88003A	N/A	Apr-16	$ 1,400,000				
10	Allings Crossing - Elm West B - Drilled Piers - 89003B	N/A	Apr-16	$ 2,500,000				
11	Milvon Take Off	N/A	Dec-16	$ 2,000,000				
12	Devon - Tie Bus Upgrade	N/A	Jun-16	$ 1,300,000				
13	Other Forecasted Plant in Service less than $1M	N/A	Various	$ 5,250,000				
14				$ 66,650,000		$ 13,559,948	19,871,253	$ 0.6824
15	Carrying Charge Factor (CCF)			21.46%	Line 32 below			
16	Subtotal Forecasted Rev Req'ts for FTPA (Lines 14*15)			$ 14,304,487				
17	ADIT Adjustment - IRS Proration			$ 6,185,192	Proration of Forecasted, Line 24			
18	Cost of Capital Rate			12.04%	Line 28 below			
19	Revenue Requirement Associated with ADIT Adjustment (Line 17*Line 18)			$ 744,539				
20	Total Forecasted Rev Req'ts for FTPA (Lines 16 - Line 19)			$ 13,559,948				
21	PTF Transmission Plant			$ 570,056,627	Worksheet 1, line 1			
22	Carrying Charge Factor			19.71%	Worksheet 1, Line 32			
23	Adjustment to carrying charge factor to reflect removal of ADIT that is subject to normalization							
24	Transmission Related ADIT Balance at 12/31/2015			$ 108,923,263	Proration of Forecasted, Line 3			
25	Post-96 PTF Transmission Plant Allocation Factor			76.03%	Worksheet 5, Line 3			
26	Transmission Related ADIT Balance - Post-96 PTF Total (line 24*25)			$ 82,811,819				
27	Cost of Capital Rate			12.04%	Worksheet 2a			
28	Total Return and Income Taxes Associated with Post-96 PTF ADIT (Line 26*Line 27)			$ 9,968,423				
29	Original Carrying Charge Factor			19.71%	Line 22 above			
30	Incremental CCF Adjustment for Post-96 PTF ADIT (Line 28/Line 21)			1.75%				
31	New Carrying Charge Factor (Line 29 + Line 30)			21.46%				

The United Illuminating Company
Accumulated Deferred Income Taxes(ADIT)

Workpaper 1

Line No.	Description	Balance 12/31/2015
1	282330 - ACCUM DEF INC TAX-OTH PROP -FIT- ACCL DEP CCBT/SB2	$ 333,264
2	282335 - ACCUM DEF INC TAX-OTH PROP-CCBT- ACCL DEP CCBT/SB2	(923,184)
3	282351 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 81	(1,209,491)
4	282352 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 82	(1,039,637)
5	282353 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 83	(613,900)
6	282354 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 84	(1,001,007)
7	282355 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 85	(8,502,667)
8	282356 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 86	(185,585)
9	282357 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 87	(909,245)
10	282358 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 88	(872,424)
11	282359 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 89	(1,776,685)
12	282360 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 90	3,136,699
13	282361 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 91	(3,781,914)
14	282362 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 92	(4,643,187)
15	282363 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 93	(3,911,547)
16	282364 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 94	(7,621,346)
17	282365 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 95	(6,042,713)
18	282366 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 96	(2,449,424)
19	282367 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 97	(2,719,701)
20	282368 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 98	(1,962,609)
21	282369 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 99	(1,609,038)
22	282370 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 00	(2,004,757)
23	282371 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 01	116,181
24	282372 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 02	(2,685,811)
25	282373 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 03	(2,879,488)
26	282374 - ACCUM DEF INC TAX- OTH PROP-FIT DEP DIF POST 2003T	(268,852)
27	282375 - ACCUM DEF INC TAX- OTH PROP-FIT DEP DIF 2004 OTHER	(2,975,826)
28	282376 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 2005 T	(242,510)
29	282377 - ACCUM DEF INC TAX- OTH PROP-FIT DEP DIF 2005 NON T	(2,731,578)
30	282378 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 2006 T	(112,506)
31	282379 - ACCUM DEF INC TAX- OTH PROP-FIT DEP DIF 2006 NON T	(3,241,987)
32	282380 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 2007 T	(21,928)
33	282381 - ACCUM DEF INC TAX- OTH PROP-FIT DEP DIF 2007 NON T	(2,981,142)
34	282382 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 2008 T	(40,084,725)
35	282383 - ACCUM DEF INC TAX- OTH PROP-FIT DEP DIF 2008 NON T	(5,573,681)
36	282384 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 2009 T	(1,214,746)
37	282385 - ACCUM DEF INC TAX- OTH PROP-FIT DEP DIF 2009 NON T	(2,916,708)
38	282386 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 2010 T	(873,755)
39	282387 - ACCUM DEF INC TAX- OTH PROP-FIT DEP DIF 2010 NON T	(4,565,701)
40	282388 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 2011 T	(9,221,261)
41	282389 - ACCUM DEF INC TAX- OTH PROP-FIT DEP DIF 2011 NON T	(9,489,217)
42	282390 - ACCUM DEF INC TAX-OTH PROP-CCBT DEP DIF 2011 NON T	
43	282391 - ACCUM DEF INC TAX - OTH PROP - FIT DEPR DIF 2012 T	(12,775,682)
44	282392 - ACCUM DEF INC TAX- OTH PROP-FIT DEP DIF 2012 NON T	(21,274,642)
45	282393 - ACCUM DEF INC TAX-OTH PROP-CCBT DEP DIF 2012 NON T	
46	282394 - ACCUM DEF INC TAX - OTH PROP- FIT DEP DIF - 2013 T	(12,700,804)
47	282395 - ACCUM DEF INC TAX-OTH PROP-FIT DEP DIF- 2013 NON T	(15,916,657)
48	282396 - ADIT - OTH PROP - CCBT DEP DIF - 2013 NON T	
49	282397 - ACCUM DEF INC TAX - OTH PROP- FIT DEP DIF - 2014 T	(3,156,531)
50	282398 - ACCUM DEF INC TAX-OTH PROP-FIT DEP DIF- 2014NON T	(18,435,908)
51	282430 - ACCUM DEF INC TAX- OTH PROP-FIT CON O/H CCBT/SB2	38,808
52	282435 - ACCUM DEF INC TAX- OTH PROP- CCBT CON O/H CCBT/SB2	(88,476)
53	282496 - ACCUM DEF INC TAX - OTH PROP - FIT 109 ADJUSTMENT	(63,769,316)
54	282497 - ACCUM DEF INC TAX- OTH PROP- CCBT 109 ADJUSTMENTS	(45,271,058)
55	Total Account 282	$(335,625,605)
56	Plant Allocation Factor	32.4538%
57	Account 282 Transmission	$(108,923,263)

ISO-NE Tariff Billing
PTO Annual Transmission Revenue Requirements
per OATT Attachment F
Adjusted to Reflect ADIT Proration

Submitted on:	June 15, 2016
Revenue Requirements for (test year):	Calendar Year 2015
Rates Effective for the period:	June 1, 2016
through:	May 31, 2017
Customer:	VT TRANSCO LLC
Customer's NABs Number:	52
Name of Participant responsible for customer's billing:	VT TRANSCO LLC
DUNs number of Participant responsible for customer's billing:	78-0399163

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	= $ 10,045,136	(a)	$ 130,166,431	(f)
Total of Attachment F - Section J - Support Revenue	-	(b)	-	(g)
Total of Attachment F - Section K - Support Expense	912,673	(c)	28,211	(h)
Total of Attachment F - Section (L through O)	37,459	(d)	484,950	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	10,995,268	(e)=(a)-(b)+(c)+(d)	130,679,592	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A		6,131,189	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	(486,760)	(l)	(1,503,065)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	**$ 10,508,508**	(n)=(e)+(l)	**$ 135,307,716**	(o)=(j)+(k)+(m)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements, and True-ups (including interest) **$ 145,816,223** (p) = (n)+(o)

VT TRANSCO
Post-96 RNS Revenue Requirements
Adjusted to Reflect ADIT Proration

Line No.	FORECASTED TRANSMISSION REVENUE REQUIREMENTS (FTRR)	Forecast Period	Attachment F Reference Section:	Amount	Reference
1	Forecasted Transmission Plant Additions (FTPA)	2016		$ 35,240,000	
2	Carrying Charge Factor (CCF)			19.13%	line 26 below
3	Subtotal Forecasted Rev Req'ts for FTPA (Line 1 x Line 2)			6,743,092	
4	ADIT Adjustment - IRS Proration			5,032,838	ADIT Proration, Line 24
5	Cost of Capital Rate			12.15822%	Worksheet 2
6	Revenue Requirement Associated with ADIT Adjustment (Line 4 x Line 5)			611,903	
7	Total Forecasted Rev Req'ts for FTPA (Lines 3 - Line 6)			6,131,189	
	DERIVATION OF CARRYING CHARGE FACTOR (CCF)				
8	Investment Return and Income Taxes		(A)	$ 76,762,228	Worksheet 1, line 14
9	Depreciation Expense		(B)	24,844,209	Worksheet 1, line 15
10	Amortization of Loss on Reacquired Debt		(C)	-	Worksheet 1, line 16
11	Amortization of Investment Tax Credits		(D)	-	Worksheet 1, line 17
12	Municipal Taxes		(E)	13,325,596	Worksheet 1, line 18
13	Payroll Taxes		(F)	893,786	Worksheet 1, line 19
14	Operation and Maintenance Expense		(G)	6,838,982	Worksheet 1, line 20
15	Administrative and General Expense		(H)	6,225,755	Worksheet 1, line 21
16	Total Expenses (Lines 8 thru 15)			128,890,556	
17	PTF Transmission Plant		(A)(1)(a)	$ 725,220,719	Worksheet 1, line 1
18	Carrying Charge Factor (Lines 16/17)			17.77%	
	Adjustment to carrying charge factor to reflect removal of ADIT that is subject to normalization.				
19	Transmission Related ADIT Balance at 12/31/2015			109,016,815	Sheet 2, Line 4
20	Post-96 PTF Transmission Plant Allocation Factor			74.5312%	Worksheet 5, line 3
21	Transmission Related ADIT Balance - Post-96 PTF Total (Line 19 x Line 20)			81,251,540	
22	Cost of Capital Rate (Line 8)			12.15822%	Line 8
23	Total Return and Income Taxes Associated with Post-96 PTF ADIT (Line 21 x Line 22)			9,878,741	
24	Original Carrying Charge Factor (Line 18 above)			17.77%	
25	Incremental CCF Adjustment for Post-96 PTF ADIT (Lines 23/17)			1.36%	
26	New Carrying Charge Factor (Line 24 + Line 25)			19.13%	

VT TRANSCO
Proration of Forecasted PTF Accumulated Deferred Income Taxes (ADIT)

Line No.	Description	Amount	Reference
1	Total ADIT Balance at 12/31/2015	109,017,578	WS 3, Line 8
2	Transmission Plant Allocation Factor	99.9993%	WS 5, Line 16
3	Transmission Related ADIT Balance at 12/31/2015	109,016,815	(Line 1 x Line 2)
4	Transmission Related ADIT Balance at 12/31/2015	109,016,815	(Line 3)
5	Post-96 and Pre-97 PTF Plant Allocation Factors	80.2882%	WS 5, Line 3
6	PTF ADIT as of 12/31/2015	87,527,638	(Line 4 x Line 5)
7	Forecasted Transmission Related ADIT balance at 12/31/2016	122,548,543	VTransco Records
8	Post-96 and Pre-97 PTF Plant Allocation Factors	80.2882%	(Line 5)
9	Forecasted PTF ADIT 12/31/2016	98,392,019	(Line 7 x Line 8)
10	Change in ADIT 2015 to 2016	10,864,381	(Line 9 - Line 6)
11	Monthly Change in ADIT	905,365	(Line 10 /12 months)

	(A) Month	(B) Remaining Days	(C) = (B)/ Line 25(B) IRS Proration %	(D) = Line 11 *(C) Prorated ADIT	
12	Month 1	335	91.7808%	830,952	
13	Month 2	307	84.1096%	761,499	
14	Month 3	276	75.6164%	684,605	
15	Month 4	246	67.3973%	610,191	
16	Month 5	215	58.9041%	533,297	
17	Month 6	185	50.6849%	458,884	
18	Month 7	154	42.1918%	381,990	
19	Month 8	123	33.6986%	305,096	
20	Month 9	93	25.4795%	230,682	
21	Month 10	62	16.9863%	153,788	
22	Month 11	32	8.7671%	79,374	
23	Month 12	1	0.2740%	2,480	
24	Total Prorated ADIT Change (Sum of 12 through 23)			$ 5,032,838	To FTTR, Line 4
25	Number of Days in the Year	365			

Attachment 4

IRS Private Letter Ruling 201541010

Internal Revenue Service

Number: **201541010**
Release Date: 10/9/2015

Index Number: 167.22-01

Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.

Telephone Number:

Refer Reply To:
CC:PSI:B06
PLR-143241-14

Date:
July 06, 2015

LEGEND:

Taxpayer =

Parent =

State A =
State B =
Commission A =
Commission B =
Commission C =
Operator =
Year A =
Case A =
Case B =
Case C =
Date X =
Director =

Dear :

This letter responds to Parent's request, made on behalf of Taxpayer, dated January 9, 2015, for a ruling on the application of the normalization rules to certain regulatory procedures applied in State as described below.

The representations set out in your letter follow.

Taxpayer, a wholly-owned subsidiary of Parent, is primarily engaged in the business of generating, transmitting, distributing, and selling electric power to customers in State A and State B. It is subject to regulation by Commission A, Commission B, and Commission C with respect to terms and conditions of services, including the rates it may charge for its services. All three Commissions establish Taxpayer's rates based on Taxpayer's costs, including a provision for a return on the capital employed by Taxpayer in its regulated business.

The law of State A provides a process under which a utility may recover its costs relating to projects such as new electric generation facilities as a stand-alone rate adjustment added to customers' base rates. As relevant to this ruling request, the process for setting the rates involves two components. First, a taxpayer files estimated projections of all factors, including Accumulated Deferred Federal Income Taxes (ADFIT), relevant to the costs associated with the facility that is the subject of the rate adjustment. Rate base for this purpose is calculated using an average of the thirteen projected end of month balances of the components of rate base. The rate adjustment computed using these projections goes into effect at the beginning of the test period. The test period is a twelve month period. The anticipated collections from rate payers, the actual cost incurred with respect to the generating facility and any differences between anticipated amounts and actual amounts are reconciled by a "true-up" mechanism at the end of the test year. Under this mechanism, the reconciliation amount is either charged to ratepayers (if actual revenues are below estimates) or credited to ratepayers (if actual revenues exceed estimates) as part of the rates established for the forthcoming rate year. For both under and over collections, a carrying charge is imposed.

Taxpayer owns and operates electric transmission lines in several states, including State A and State B. These lines are integrated into Operator, a regional transmission operator. The rates that Taxpayer may charge its customers for these transmission services are set using a formula approved by Commission C. The formula rates are calculated using a methodology similar to that used to calculate the rate adjustments, inasmuch as the formula rates are calculated using projected costs to establish rates during the period for which rates are being set and a true-up based on over or under recoveries that are reflected in a subsequent rate year. The rates are determined by application of the formula approved by Commission C and go into effect with no additional action by Commission C.

Taxpayer claims accelerated depreciation on its tax returns to the extent permitted by the Internal Revenue Code. Taxpayer normalizes the federal income taxes deferred as a result of its use of accelerated depreciation and thus maintains an ADFIT balance on its regulatory books. In ratemaking proceedings before Commission A to authorize rate adjustments as well as in calculation of the formula rates, rate base is reduced by the calculated ADFIT balance. In calculating its ADFIT balance for purposes of both the projection and true-up elements of the rate adjustment calculations, Taxpayer followed the same averaging conventions it used for the other components of rate base. However, for prior formula rate filings, Taxpayer had calculated its ADFIT balance by an average of the beginning and ending balances notwithstanding that it used a 13-month average for computation of the plant portion of rate base. In those prior cases, the averages are calculated in accordance with the provisions of the Commission-approved template and the differences in averaging conventions are required by the regulations adopted by Commission C.

Section 1.167(l)-1(h)(6) of the Income Tax Regulations requires that a proration methodology be used by Taxpayer to calculate its applicable ADFIT balance for future test periods. Prior to Year A, Taxpayer had not used the proration methodology either in estimating its projected ADFIT balance or for the calculation of ADFIT for purposes of the true-up. Members of Taxpayer's tax department became concerned about the normalization implications of not using the proration formula during Year A. In filing Case A, Case B, and Case C, Taxpayer incorporated the proration methodology into the calculation of its projected ADFIT balance. In addition, Taxpayer incorporated the proration methodology into the calculation of the true-up in Case B. The staff of Commission A did not agree that the test period used for the rate adjustment ratemaking was a future test period and therefore asserted that the proration methodology was not required. In each of these cases, Commission A approved the use of the proration methodology in the projected ADFIT balance but denied its use in the true-up. When Commission A approved the use of the proration methodology for the projected ADFIT balance, it revised a portion of the Taxpayer's cash working capital allowance to reflect the adoption of the proration methodology. The adjusted portion was intended to compensate Taxpayer for the lag in time between when expenditures are made for services by Taxpayer and when collections for those services are received by Taxpayer. Commission A concluded that the item in the cash working capital allowance was duplicative of the effect of the proration methodology and was thus unnecessary. Due to the uncertainty surrounding the application of the proration methodology and the adjustment to cash working capital, Commission A directed Taxpayer to seek this ruling from the Internal Revenue Service.

Both Commission A and Commission C at all times have required that all public utilities under their respective jurisdictions use normalized methods of accounting.

Taxpayer requests that we rule as follows:

1. The proration methodology requirement does not apply to stand-alone rate adjustment ratemaking and to the Commission C formula rates even if they involve future test periods.
2. The estimated projection component of both the stand-alone rate adjustment ratemaking and the formula rate does not employ a future test period within the meaning of § 1.167(l)-1(h)(6)(ii) and therefore Taxpayer is not required to use the proration methodology in order to comply with the normalization rules.

3. The true-up component of both the stand-alone rate adjustment ratemaking and the formula rate does not employ a future test period within the meaning of § 1.167(l)-1(h)(6)(ii) and therefore Taxpayer is not required to use the proration methodology in order to comply with the normalization rules.
4. In Taxpayer's stand-alone rate adjustment proceedings, an adjustment to eliminate from the Taxpayer's cash working capital allowance any provision for accelerated depreciation-related ADFIT if the proration methodology is employed does not conflict with the normalization rules.
5. In order to comply with the consistency requirement of the normalization rules, it is not necessary that the Taxpayer use the same averaging convention it uses in computing the other elements of rate base in computing its ADFIT balance for purposes of the formula rates.
6. If the Service rules adversely with respect to Rulings 1, 2, or 3, above, any failure by Taxpayer to employ the proration methodology prior to the proceedings in Cases A, B, or C or the effective date approved by Commission C for the requested modification of the formula rates was not a violation of the normalization rules requiring sanctions for such violation.
7. In the event that the Service rules adversely with respect to Ruling 5, above, Taxpayer's failure to comply with the consistency requirement in connection with its formula rates prior to the effective date approved by Commission C for the requested modification of the formula rates was not a violation of the normalization rules.

Law and Analysis

Issues 1 and 2

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A) requires that a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 1.167(l)-1(h)(6) sets forth additional normalization requirements with respect to public utility property. Under § 1.167(l)-1(h)(6)(i), a taxpayer does not use a normalization method of accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes excluded from the rate base, or treated as cost-free capital, exceeds the amount of the reserve for the period used in determining the taxpayer's ratemaking tax expense. Section 1.167(l)-1(h)(6)(ii) also provides the procedure for determining the amount of the reserve for deferred taxes to be excluded from rate base or to be included as no-cost capital. If, in determining depreciation for ratemaking tax expense, a period (the "test period") is used which is part historical and part future, then the amount of the reserve account for this period is the amount of the reserve at the end of the historical portion of the period and a pro rata amount of any projected increase to be credited to the account during the future portion of the period. The pro rata amount of any increase during the future portion of the period is determined by multiplying the increase by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period.

Section 1.167(l)-1(h)(6)(i) makes it clear that the reserve excluded from rate base must be determined by reference to the same period as is used in determining ratemaking tax expense. A taxpayer may use either historical data or projected data in calculating these two amounts, but it must be consistent. As explained in section 1.167(l)-1(a)(1), the rules provided in section 1.167(l)-1(h)(6)(i) are to insure that the same time period is used to determine the deferred tax reserve amount resulting from the use of an accelerated method of depreciation for cost of service purposes and the reserve amount that may be excluded from the rate base or included in no-cost capital in determining such cost of services.

If a taxpayer chooses to compute its ratemaking tax expense and rate base exclusion amount using projected data then it must use the formula provided in section 1.167(l)-1(h)(6)(ii) to calculate the amount of deferred taxes subject to exclusion from the rate base. This formula prorates the projected accruals to the reserve so as to account for the actual time these amounts are expected to be in the reserve. As explained in § 1.167(l)-1(a)(1), the formula in section 1.167(l)-1(h)(6)(ii) provides a method to determine the period of time during which the taxpayer will be treated as having received amounts credited or charged to the reserve account so that the disallowance of earnings with respect to such amounts through rate base exclusion or treatment as no-cost capital will take into account the factor of time for which such amounts are held by the taxpayer.

The purpose of the proration formula is to prevent the immediate flow-through of the benefits of accelerated depreciation to ratepayers. The proration formula stops flow-through by limiting the deferred tax reserve accruals that may be excluded from rate base, and thus the earnings on rate base that may be disallowed, according to the length of time these accruals are actually in the reserve account.

The effectiveness of § 1.167(l)-1(h)(6)(ii) in resolving the timing issue has been questioned by its failure to define some key terms. Nowhere does this provision state what is meant by the terms "historical" and "future" in relation to the period for determining depreciation for ratemaking tax expense (the "test period"). One interpretation focuses on the type or quality of the data used in the ratemaking process. According to this interpretation, the historical period is that portion of the test period for which actual data is used, while the portion of the period for which data is estimated is the future period. The second interpretation focuses on when the utility rates become effective. Under this interpretation, the historical period is that portion of the test period before rates go into effect, while the portion of the test period after the effective date of the rate order is the future period.

The first interpretation, which focuses on the quality of the ratemaking data, is an attractive one. It proposes a simple rule, easy to follow and to enforce: any portion of the reserve for deferred taxes based on estimated data must be prorated in determining the amount to be deducted from rate base. The actual passage of time between the date ratemaking data is submitted and the date rates become effective is of no importance. But this interpretation of the regulations achieves simplicity at the expense of precision; in other words, it is overbroad. The proration of all estimated deferred tax data does serve to magnify the benefits of accelerated depreciation to the utility, but this is not the purpose of normalization. Congress was explicit: normalization "in no way diminishes whatever power the [utility regulatory] agency may have to require that the deferred taxes reserve be excluded from the base upon which the utility's permitted rate of return is calculated." H.R. Rep. No. 413, 91st Cong., 1st Sess. 133 (1969).

In contrast, the second interpretation of section 1.167(l)-1(h)(6)(ii) of the regulations is consistent with the purpose of normalization, which is to preserve for regulated utilities the benefits of accelerated depreciation as a source of cost-free capital. The availability of this capital is ensured by prohibiting flow-through. But whether or not flow-through can even be accomplished by means of rate base exclusions depends primarily on whether, at the time rates become effective, the amounts originally projected to accrue to the deferred tax reserve have actually accrued.

If rates go into effect before the end of the test period, and the rate base reduction is not prorated, the utility commission is denying a current return for accelerated depreciation benefits the utility is only projected to have. This procedure is a form of flow-through, for current rates are reduced to reflect the capital cost savings of accelerated depreciation deductions not yet claimed or accrued by the utility. Yet projected data is often necessary in determining rates, since historical data by itself is rarely an accurate indication of future utility operating results. Thus, the regulations provide that as long as the portion of the deferred tax reserve based on projected (future estimated) data is prorated according to the formula in section 1.167(l)-1(h)(6)(ii), a regulator may deduct this reserve from rate base in determining a utility's allowable return. In other words, a utility regulator using projected data in computing ratemaking tax expense and rate base exclusion must account for the passage of time if it is to avoid flow-through.

But if rates go into effect after the end of the test period, the opportunity to flow through the benefits of future accelerated depreciation to current ratepayers is gone, and so too is the need to apply the proration formula. In this situation, the only question that is important for the purpose of rate base exclusion is the amount in the deferred tax reserve, whether actual or estimated. Once the future period, the period over which accruals to the reserve were projected, is no longer future, the question of when the amounts in the reserve accrued is no longer relevant (at the time the new rate order takes effect, the projected increases have accrued, and the amounts to be excluded from rate base are no longer projected but historical, even though based on estimates).

There are two kinds of ratemaking at issue here, with identical components. For both the stand-alone rate adjustment and the formula rates, Taxpayer estimates the various components of rate base. Rates go into effect as of the beginning of the service year.[1] As such, the rates are in effect during the test year and the proration formula must be used. The addition of the true up increases the ultimate accuracy of the rates but does not convert a future test period into a historical test period as those terms are used in the normalization regulations. Therefore, Taxpayer is required to apply the proration formula in calculating accumulated deferred income taxes for purposes of calculating rate base.

Issue 3

[1] We note that, because Taxpayer is using estimated data for the test period, the test period at issue here constitutes a “future test period” under the first interpretation discussed above as well.

As discussed above, where a taxpayer computes its ratemaking tax expense and rate base exclusion amount using projected data then must use the proration formula provided in section 1.167(l)-1(h)(6)(ii) to calculate the amount of deferred taxes subject to exclusion from the rate base. This formula prorates the projected accruals to the reserve so as to account for the actual time these amounts are expected to be in the reserve. As explained in § 1.167(l)-1(a)(1), the formula in section 1.167(l)-1(h)(6)(ii) provides a method to determine the period of time during which the taxpayer will be treated as having received amounts credited or charged to the reserve account so that the disallowance of earnings with respect to such amounts through rate base exclusion or treatment as no-cost capital will take into account the factor of time for which such amounts are held by the taxpayer.

The purpose of the proration formula is to prevent the immediate flow-through of the benefits of accelerated depreciation to ratepayers. The proration formula stops flow-through by limiting the deferred tax reserve accruals that may be excluded from rate base, and thus the earnings on rate base that may be disallowed, according to the length of time these accruals are actually in the reserve account.

In contrast to the projections discussed above, the true-up component is determined by reference to a purely historical period and there is no need to use the proration formula to calculate the differences between Taxpayer's projected ADFIT balance and the actual ADFIT balance during the period. In calculating the true-up, proration applies to the original projection amount but the actual amount added to the ADFIT over the test year is not modified by application of the proration formula.

Issue 4

In Taxpayer's stand-alone rate adjustment proceedings, Commission A adjusted the already-approved cash working capital allowance specifically to mitigate the effect of the use of the proration methodology, finding the effects duplicative. In general, taxpayers may not adopt any accounting treatment that directly or indirectly circumvents the normalization rules. See generally, § 1.46-6(b)(2)(ii) (In determining whether, or to what extent, the investment tax credit has been used to reduce cost of service, reference shall be made to any accounting treatment that affects cost of service); Rev. Proc 88-12, 1988-1 C.B. 637, 638 (It is a violation of the normalization rules for taxpayers to adopt any accounting treatment that, directly or indirectly flows excess tax reserves to ratepayers prior to the time that the amounts in the vintage accounts reverse). Here, Commission A adjusted the cash working capital allowance specifically to mitigate the effect of the application of the proration methodology. This is inconsistent with the normalization rules. We do not hold that the normalization rules require a similar type of cash working capital adjustment in all cases; we hold only that, where, as here, it is adjusted or removed in an attempt to mitigate the effects of the application of the proration methodology or similar normalization rule, that adjustment or removal is not permitted under the normalization rules.

Issue 5

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A) requires that a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

In order to satisfy the requirements of §168(i)(9)(B), there must be consistency in the treatment of costs for rate base, regulated depreciation expense, tax expense, and deferred tax revenue purposes. Here, rate base, depreciation expense, and accumulated deferred income taxes are all calculated in consistent fashion – all are averaged over the same period. While there are minor differences in the convention used to average all elements of rate base including depreciation expense on the one hand, and ADFIT on the other, for purposes of §168(i)(9)(B), it is sufficient that both are determined by averaging and both are determined over the same period of time. Thus, the calculation of average rate base and accumulated deferred income taxes as described above complies with the consistency requirement of §168(i)(9)(B).

Because of the conclusion reached above, Taxpayer's seventh issue is moot and will not be considered further.

Issue 6

Because the Service has ruled in Issue 1 and 2 that Taxpayer was required to use the proration formula applicable to future test periods for the projected revenue requirement, prospectively adhering to the Service's interpretation of § 1.167(l)-1(h)(6)(ii) require adjustments to conform to this ruling. Any rates that have been calculated using procedures inconsistent with this ruling ("nonconforming rates") which are or which have been in effect and which, under applicable state or federal regulatory law, can be adjusted or corrected to conform to the requirements of this ruling, must be so adjusted or corrected. Where nonconforming rates cannot be adjusted or corrected to conform to the requirements of this ruling due to the operation of state or federal regulatory law, then such correction must be made in the next regulatory filing or proceeding in which Taxpayer's rates are considered. Specifically, the current timing of Taxpayer's stand-alone rate adjustment filings with Commission A will accommodate all adjustments or corrections to any prior estimated projections or true-ups necessary to conform to the requirements of this ruling in rates having an effective date no later Date X, including Case A, Case B, and Case C. In addition, Taxpayer has already sought an order from Commission C to make the necessary changes to the rate templates, not simply unilaterally adjusting the calculations (or the manner in which the templates are completed) in the next annual projections or true-up adjustments. If Taxpayer must request these changes through a filing with Commission C, Taxpayer has represented that it will make a filing with Commission C to amend its formula rate template within six months of receipt of this ruling letter, requesting that Commission C apply a methodology in accordance with this letter using an effective date of the first month following the date of the filing made with Commission C. Following Commission C's order in that filing, Taxpayer will prospectively apply the methodology consistent with this letter approved by Commission C. Until Commission C acts on the filing, Taxpayer will continue to use the methodology described above.

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit, Congress has stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581.

Here, Taxpayer has received stand-alone rate adjustments from Commission A without application of the proration methodology as required. In addition, Taxpayer used a template approved by Commission C to calculate formula-based rates. Both Commission A and Commission C have, at all times, required that utilities under their respective jurisdictions use normalization methods of accounting. Taxpayer also intended at all times to comply with the normalization rules. As concluded above, Taxpayer was required to use the proration methodology in these ratemaking proceedings. However because Commissions A and C as well as Taxpayer at all times sought to comply, and because Taxpayer will take the corrective actions described above, it is not currently appropriate to apply the sanction of denial of accelerated depreciation to Taxpayer.

Conclusions

1. The proration methodology requirement applies to all future test periods.
2. The estimated projection component of both the stand-alone rate adjustment ratemaking and the formula rate does employ a future test period within the meaning of § 1.167(l)-1(h)(6)(ii) and therefore Taxpayer is required to use the proration methodology in order to comply with the normalization rules.
3. The true-up component of both the stand-alone rate adjustment ratemaking and the formula rate does not employ a future test period within the meaning of § 1.167(l)-1(h)(6)(ii) and therefore Taxpayer is not required to use the proration methodology in order to comply with the normalization rules.
4. In Taxpayer's stand-alone rate adjustment proceedings, an adjustment to eliminate from the Taxpayer's cash working capital allowance any provision for accelerated depreciation-related ADFIT if the proration methodology is employed does conflict with the normalization rules.
5. In order to comply with the consistency requirement of the normalization rules, it is not necessary that the Taxpayer use the same averaging convention it uses in computing the other elements of rate base in computing its ADFIT balance for purposes of the formula rates.

6. The Service rules adversely with respect to Rulings 1 and 2, above. Any failure by Taxpayer to employ the proration methodology prior to the proceedings in Cases A, B, or C or the effective date approved by Commission C for the requested modification of the formula rates was not a violation of the normalization rules requiring sanctions for such violation.
7. Because the Service rules favorably with respect to Ruling 5, above, Taxpayer's requested Ruling 7 is moot.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman
Senior Technician Reviewer, Branch 6
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Attachment 5

Service List of Participating Transmission Owners

Service List of
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Attachment 6

Service List of State Regulators and Other Interested Parties

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