Jennifer Brooks Hutchinson
Acting Assistant General Counsel and Director

October 13, 2020

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4770 – Electric Earnings Sharing Mechanism
Earnings Report - Twelve Months Ended December 31, 2019
<u>Responses to PUC Data Request – Set 3</u>

Dear Ms. Massaro:

On behalf of National Grid[1] I have enclosed an electronic version of the Company's responses to the Public Utilities Commission's Third Set of Data Requests in the above-referenced matter.[2]

The Company's responses to PUC 3-7, 3-8, and 3-17 through 3-19 are forthcoming. The Company received an extension on the following requests: PUC 3-10, 3-11, 3-14, 3-16, 3-20, and 3-25.

Thank you for your attention to this transmittal. If you have any questions regarding this filing, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Docket 4770 Service List
John Bell, Division
Christy Hetherington, Esq.
Leo Wold, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

[2] Per Commission counsel's update on October 2, 2020, concerning the COVID-19 emergency period, the Company is submitting an electronic version of this filing. The Company will provide the Commission Clerk with a hard copy and, if needed, additional hard copies of the enclosures upon request.

280 Melrose Street, Providence, RI 02907
T: 401-784-7288 ■ jennifer.hutchinson@nationalgrid.com ■ www.nationalgrid.com

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

Joanne M. Scanlon	October 13, 2020 Date

National Grid Docket No. 4770 (Rate Application) & Docket No. 4780 (PST)
Combined Service list updated 8/12/2020

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PRISM & WCRPC c/o Jeff Broadhead, Executive Director	jb@wcrpc.org;	401-792-9900
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PUC 3-1

Request:

Please provide a copy of New England Power Company's Electric Tariff No. 1 and a copy of New England Power Company's Schedule 21-NEP.

Response:

See copy of New England Power Company's Electric Tariff No. 1, attached hereto and made a part hereof as Attachment PUC 3-1-1.

See Copy of Schedule 21-NEP attached hereto and made a part hereof as Attachment PUC 3-1-2.

FERC ELECTRIC TARIFF

SECOND REVISED VOLUME NUMBER 1

OF

NEW ENGLAND POWER COMPANY

Filed with

FEDERAL ENERGY REGULATORY COMMISSION

Communications concerning this
Tariff should be addressed to:

Director of Rates
New England Power Company
40 Sylvan Road
Waltham, Massachusetts 02451

NEW ENGLAND POWER COMPANY

Primary Service for Resale

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NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers
General Terms and Conditions

Schedule I

A. Tariff.

Primary Service for resale and transmission service for Partial Requirements Customers are available only upon execution of a Service Agreement with the Company in the form set forth hereinafter.

Each such Service Agreement will incorporate these general terms and conditions (Schedule I), the Company's currently effective rate for primary service for resale (Schedule II), the terms and conditions applicable to the type of service to be rendered at said rate (Schedule III) and the specific interconnection arrangements with the Customer.

The Company will file each such Service Agreement with the Federal Energy Regulatory Commission (and such other regulatory agency as may have jurisdiction in the premises) in accordance with the provisions of applicable laws and any rules and regulations thereunder.

B. Amendments.

It is agreed that the Company shall have the right at any time to amend the General Terms and Conditions set forth in this Schedule I to the tariff, the Rate Provisions set forth in Schedule II to the tariff, the Terms and Conditions governing specified types of service set forth in Schedule III to the tariff, and the form of Service Agreement set forth in Schedule IV to the tariff, by serving an appropriate statement of such amendment upon the Customer and filing the same with the Federal Energy Regulatory Commission (and such other regulatory agency as may have jurisdiction in the premises) in accordance with the provisions of applicable laws and any rules and regulations thereunder, and the amendment shall thereupon become effective on the date specified therein, subject to any suspension order duly issued by such agency.

C. Regulation.

This tariff, any Service Agreement executed pursuant thereto, and all the rights, obligations and performance of the parties to such service agreement, are subject to the Federal Power Act and to all other applicable state and federal laws and to all duly promulgated rules, regulations and orders of the Federal Power Commission and any other regulatory agency having jurisdiction in the premises.

The obligations of the parties are further subject to and conditioned upon their securing and retaining all rights-of-way, franchises, locations, permits and other rights and approvals necessary in order to permit service to be rendered as set forth in the Service Agreement, and each party agrees to use its best efforts to secure and retain all such rights-of-way, franchises, and other rights and approvals.

D. Availability of primary service for resale.

Primary service for resale is available only to electric utilities (including municipalities) engaged in the distribution of electricity to the public, whose electric requirements are supplied in whole or in part by the Company, either directly or over facilities for the use of which the Company has contractual arrangements.

Electricity so supplied is available for the Customer's own use and for resale to ultimate customers in the Customer's service area as it may exist from time to time, which area shall consist of one or more Districts to be specified in the Service Agreement. If the Customer's service area consists of two or more Districts, all provisions of the tariff shall apply to each District separately.

Primary service for resale is also available for sales for resale by the Customer (1) to electric utilities served by the Customer as of the date of and as specified in the Service Agreement; (2) to additional electric utilities which shall then be specified in the Service Agreement; and (3) under convenience contracts for the supply of electricity to borderline customers. With reference to sales under (2) above, the Customer shall give to the Company seven years' notice of intention to serve such utilities; the Customer shall furnish such information as the Company may reasonably request; and the parties shall establish mutually agreeable reasonable terms in connection therewith.

Service for Resale to Interruptible Customers under Schedule III-C is available only to utilities who are also taking service under Schedule III-A or III-B.

The Customer's sources of supply other than the Company shall be specified in the Service Agreement; and seven years' notice shall be given by the Customer to the Company of a change in Customer's source or sources, and such change shall be implemented pursuant to mutually agreed upon reasonable terms.

E. Availability of transmission service.

The types of transmission service available to the Partial Requirements Customer are specified in Schedule III to the tariff, and the Company will consider requests for additional types of transmission service; in each case to the extent that the Company deems its existing and planned transmission capacity can accommodate such additional service without additional new construction. In cases where new construction may be required to accommodate additional types of transmission service, the Company reserves the right in its discretion either to refuse to undertake such further service, or to request financial assurance that any additional transmission investments and costs will be adequately provided for.

F. Character of primary electric service.

Electricity will be supplied in the form of three-phase, sixty-hertz alternating current at the nominal voltage or voltages specified in the Service Agreement.

The Company will maintain and operate its interconnected generating and transmission system, together with any delivery facilities required for service to the Customer, in accordance with good utility practice. The Company will use due diligence in maintaining an aggregate capacity of such facilities sufficiently in excess of current Demand to allow for the Customer's expected load growth, and the Customer will keep the Company informed as to expected trends of its load growth.

The Company shall not be liable in damages to the Customer for any failure to supply electricity nor to provide transmission service in accordance with the preceding paragraphs if prevented from doing so by reason of storm, flood, earthquake, fire, explosion, civil disturbance, labor dispute, act of God or the public enemy, restraint by a court or other public authority, or any cause beyond its reasonable control; and shall not be liable in damages to the Customer for any reduction in voltage or interruption of service resulting from the operation in accordance with good utility practice of an emergency load-reduction program; but in any such case the Company will exercise due diligence to remove the cause of any disability at the earliest practicable time. The Company and the Customer shall have the obligation to operate in accordance with good utility practice, including an emergency load reduction program, and upon request, to consult with each other in regards thereto.

G. Delivery and ownership of facilities.

1. All deliveries will be made a single delivery point in each District (which may also be used to serve other customers of the Company or affiliated companies of the New England Electric System), except where District load can be more feasibly served by multiple delivery points. The Service Agreement shall set forth with respect to each District of the

Customer's system the point or points of delivery, the delivery voltage or voltages and the ownership of transformation and metering equipment.

2. Deliveries at each delivery point will be made at a single voltage except as otherwise provided in the Service Agreement.

3. All lines, apparatus and other equipment up to the point of delivery shall be supplied, maintained and operated by the Company or affiliated companies of the New England Electric System, and all such equipment beyond such point of delivery shall be supplied, maintained and operated by the Customer. The Customer shall, however, supply free of cost a suitable place for the installation of the Company's metering equipment and any of the Company's lines, or other equipment which it is proper to locate on the Customer's property, and the Company shall have access to the Customer's property for all reasonable purposes in connection therewith.

4. All the Customer's lines, apparatus and equipment (and the maintenance, operation and adjustment of the same) which are connected to the facilities of the Company, and the maintenance, operation and adjustment of which may adversely affect the operation of the Company's facilities, shall be subject to the reasonable inspection and approval of the Company.

5. The Customer assumes all responsibility for electricity beyond the point of delivery, and the Company shall not be liable for damage to the person or property of the Customer or of its employees or of any other persons resulting from the use of electricity beyond the point of delivery.

Variations from the provisions of paragraphs 1 through 5 above will be permitted, in the discretion of the Company, if and to the extent that equitable adjustments are provided for and set forth in the Service Agreement.

H. Metering.

The Company reserves the right to determine the metering installations and will supply the metering equipment for determining the quantity and conditions of supply of electricity delivered hereunder. Any exceptions to this provision shall be reflected in the Service Agreement.

If at any time such equipment shall be found to be inaccurate by more than 2% up or down, the owner shall make it accurate and the charges and meter readings for the period of inaccuracy, so far as the same can reasonably be ascertained, shall be adjusted. However, no adjustment prior to the beginning of the next preceding month shall be made except by mutual agreement.

In addition to regular routine tests, the owner shall have any such meter tested at any time upon written request of the other party, and if such meter prove accurate within 2% up or down the expense of the test shall be borne by the party requesting the test.

I. Transmission losses.

Unless otherwise specified in the tariff, all losses incurred in providing transmission service hereunder shall be for the account of the Customer, and delivery of the aggregate quantity of electricity received for transmission, less such losses, shall constitute full performance by the Company. When segregation of energy flows is required to determine such losses, the Company will calculate the same in accordance with good engineering practice.

J. Billing and payment.

Bills for each month shall be rendered during the first part of the next succeeding month and shall be due when rendered.

As used herein the term “month” shall refer to the period between two meter readings each of which shall have been taken within two days of the end of successive calendar months.

When all or part of any bill shall remain unpaid for more than thirty (30) days after the rendering thereof by the Company, interest at the rate of 1 ½% per month shall accrue to the Company from and after the rendering of said bill and be payable to the Company on either: (1) such unpaid amount or (2) in the event the amount of the bill is disputed, the amount finally determined to be due and payable.

Notwithstanding the foregoing, no late payment penalty shall be imposed upon any customer where payment is made within forty-fine (45) days of the rendering of the bill by the Company provided that each of the following conditions are met: 1) the average prior calendar year’s monthly billing to such customer was less than $45,000; and 2) payment of such bill within thirty (30) days by such customer would cause undue hardship because of the fact that one or more part-time employees or officials are essential to the processing of payment by such customer. A letter from an appropriate official of a customer certifying that one or more part-time employees are essential to the processing of payment shall constitute satisfactory evidence that condition 2 herein has been met.

In addition, no late payment penalty shall be imposed upon any customer electing to make installment payments with respect to any bill so long as the weighted average payment date, based on the amount of each payment, is no later than 30 days after the date of the rendering of the bill.

K. Remedies.

If any bill remains unpaid for more than sixty days, except amounts in dispute, the Company may apply to the regulatory agency having jurisdiction to suspend delivery of electricity until full payment has been made of all amounts due.

If either party shall have defaulted in any of its obligations and such default shall have continued for and not been remedied within sixty days after receipt of a written notice from the other party specifying the nature of such default in reasonable detail, the other party may by written notice terminate the Service Agreement at the end of the next succeeding calendar month. No delay by either party in enforcing any of its rights hereunder shall be deemed a waiver of such rights, nor shall a waiver of one default be deemed a waiver of any other or subsequent default.

The enumeration of the foregoing remedies shall not be deemed to be a waiver of any other remedies to which other party is legally entitled.

L. Hours of Labor.

The Company agrees to comply with the provisions of the General Laws of Massachusetts, Chapter 149, Section 34, as amended, with reference to the hours of laborers, workmen or mechanics in its employ, so far as the same may be applicable to work under this tariff.

M. Notices.

Notices by the Company or the Customer shall be in writing, mailed or delivered to the respective addresses set forth in the Service Agreement. Either party may change its address by written notice to the other.

N. Term.

Once initiated, service under this tariff shall continue until terminated by either party giving to the other at least seven years' written notice of termination directed to the end of a calendar month.

A Customer that seeks to terminate service without providing the notice required under this tariff and its service agreement and that has not otherwise agreed to a settlement of its early termination costs may exercise an option to terminate service under this tariff early by giving the

Company thirty days' written notice directed to the end of a calendar month and paying the Contract Termination Charge applicable under Schedule II-C of this tariff. The Contract Termination Charge shall be payable in equal monthly installments of principal and interest, the first payment to be made within 30 days after the date of termination of service ("Early Termination Date"), over the remaining term of the Customer's notice period (or such shorter term, or in a single payment, as agreed by the Company and the Customer). The Customer's payments shall include carrying charges on the unpaid amount of the Contract Termination Charge at the interest rate determined pursuant to section 35.19a of the Commission's regulations (18 C.F.R. 35.19a) effective on the Early Termination Date and compounded monthly. The Company reserves the right to require the Customer to provide security in a form appropriate to the Company and consistent with commercial practices to protect the Company against the risk of non-payment. This paragraph shall not apply to Customers that have entered into settlement agreements with the Company allowing early termination of service under this tariff and establishing the recovery of contract termination charges. The Company at its discretion may waive the thirty days' notice provision under this paragraph.

O. Successors and assigns.

The executed service agreement shall be binding upon, shall inure to the benefit of, and may be performed by, the successors and assigns of the parties.

NEW ENGLAND POWER COMPANY

Schedule II-A

THIS SECTION INTENTIONALLY LEFT BLANK

NEW ENGLAND POWER COMPANY

Schedule II-B

NEW ENGLAND POWER COMPANY
Primary Service for Resale
Rate W-95(N)

Demand Charge:	$17.17 per month for each kilowatt of Demand.
Energy Charge:	21.83 mills ($0.02183) for each kilowatt-hour of electricity delivered, except for kilowatt-hours of electricity delivered under Service for Resale to Interruptible Customers, Schedule III-C.
Interruptible Service: Charge	For each kilowatt-hour delivered in any hour pursuant to Schedule III-C, the amount specified for that hour by the Company pursuant to Paragraph C of Schedule III-C
Fuel and Purchased Economic Power Adjustment Clause:	For any month for which the Cost of Fuel is greater or less than 14.0000 mills per kilowatt-hour, the Energy Charge shall be increased or decreased respectively by the applicable fuel adjustment rate per kilowatt-hour delivered, which rate shall be equal to the difference of:

$$\frac{Fm}{Sm} - \frac{Fb}{Sb}$$

Where F is the expense of fossil and nuclear fuel and purchased economic power in the base (b) and current (m) periods; and “S” is the kilowatt-hour sales in the base and current periods, all as defined in Section 35.14 of the Regulations under the Federal Power Act as provided in Order No. 352 issued December 7, 1983 in Docket No. RM83-62-000. F shall also include expenses associated with purchases of electricity from alternate energy suppliers, provided however that payments from such suppliers due to their failure to perform or pursuant to contractual security provisions shall be credited to F above. F shall be credited with the revenues from sales for resale to interruptible customers pursuant to Schedule III-C and such sales shall be excluded from S.

As a signatory to the NEPOOL Agreement, dated as of September 1, 1971, as amended, the Company’s reserve capacity criteria is determined as a part of the NEPOOL reserve requirement. This type of interconnected pool operation avoids the need for member companies to individually determine reserve capacity criteria, while preserving individual company integrity through the basic NEPOOL Agreement. Each member utility's commitment to the Pool's requirements is assured by a monthly assessment of each members "Capability Responsibility", as defined in the NEPOOL Agreement. See also the NEPOOL Agreement, FERC Rate Schedule No. 210. In determining whether a purchase is a reliability purchase, the Company will use its then-applicable NEPOOL reserve requirement, regardless of whether the selling utility is a member of NEPOOL. In the event that a short term operating reserve purchase is made by NEPOOL and an assessable share is billed to NEP, NEP will include in this clause only the cost of fuel associated with such purchase. Part of the costs in evaluating the interchange with NEPEX (the NEPOOL dispatching agency) may initially be estimated. All energy savings shares that are created in the NEPEX dispatch are reflected in fuel costs. The value of the estimated costs will be combined with the value of the actual costs for the billing month to determine the monthly fuel clause factor. Any difference between the actual and estimated data for a billing month will be reflected in cost data utilized in the calculation for the succeeding month.

Notwithstanding the above, whenever the foregoing determination would be affected by energy produced from generating units under construction as they undergo operational tests prior to their in service dates, the components of F shall be adjusted so that its value is the same as it would have been if such test energy were not available. Such adjustment to F in the formula shall also recognize that current wholesale customers have paid a part of the cost of generating units under construction through demand charges reflecting CWIP in rate base; therefore, a credit to F shall be applied equal to the differential between the cost of test energy and the displaced cost of fuel in the ratio that demand contributions for such units bear to the carrying cost of such units.

In addition to the foregoing, F shall also include fifty percent (50%) of all natural gas transportation demand charges incurred for the period beginning November 1, 1991 and ending on the sooner to occur of January 1, 1996 or the conclusion of the construction period for the Manchester Street Station repowering project, provided, however, that revenues received from third parties related to their use of NEP's pipeline capacity during the foregoing period shall be credited to F above. Thereafter, all natural gas transportation demand charges incurred shall be included in F above.

Once each calendar year, NEP shall reconcile the total incremental fuel costs of all short-term unit sales transactions, and sales pursuant to Schedule III-C, to fuel revenue from these transactions. If the total incremental fuel cost exceeds the fuel revenue, F shall be credited with the differential. The reconciliations shall be done in accordance with the procedures set forth in Dockets 92-372-000 et al. (unit power contracts) and Docket No. 94-1056-000 (Schedule III-C sales).

In accordance with a Surcharge Compliance Filing Settlement Agreement filed in Docket Nos. ER88-630-000, et al., a monthly charge for fuel expense underrecovery will be assessed all Customers except Massachusetts Electric Company, as shown at Appendix C to that Settlement Agreement. The foregoing charge will become effective as approved by the Commission and will continue thereafter for a period of ten (10) years, provided that if any of these Customers terminates service from NEP prior to the conclusion of the amortization period, that Customer shall pay its remaining unamortized fuel expense upon the date it terminates service. The monthly charge will be: Narragansett Electric - $48,889, Granite State - $6,499, Groveland - $225, Merrimac - $196, Littleton - $535, Norwood - $3,128, N.H. Elec. Coop - $66, GMP - $52, and Ft. Devens - $540.

In accordance with the settlement of Docket No. FA91-53-000, F shall also include the 1.5% NEPEX differential billed to NEP by Central Maine Power for the use of low sulphur oil in the Wyman Units 1, 2, and 3 when Wyman 4 is operating.

Standard Delivery Point: For purposes of this Tariff, the “Standard Delivery Point” shall be considered to be that point on the integrated generating and transmission system of the Company that first follows one transformation from the power supply system or, by agreement of the parties, a point in close proximity thereto.

Metering Adjustments: Where delivery is metered at the Company’s supply line voltage, in no case less than 69,000 volts, thereby saving the Company transformer losses then, before determining the number of kilowatts and kilowatt-hours to be billed under the preceding provisions, there shall be deducted from the meter registrations of kilowatts and kilowatt-hours for the month in question an amount respectively of one percent (1.0%) of such registrations. Where delivery is metered at the sub-transmission voltage, or at the low side terminals of the transformation from the sub-transmission to the distribution of the customer, and not at the low side terminals of the transformation from the Company's supply line, there shall be added to the meter registrations of kilowatts and kilowatt-hours for the month in question an amount respectively of one and one half percent (1.5%) of such registrations.

Transformer Ownership Credit:

If delivery is made at the Company's supply line voltage, not less than 69,000 volts, and the Company is saved the cost of installing any transformer and associated equipment there will be allowed a credit of thirty cents ($0.30) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. In accordance with a Settlement Agreement in Docket Nos. ER91-565-000, et al., the credit applicable to the Town of Norwood will be twenty-one cents ($0.21) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. The foregoing credits, as applicable, shall be computed after the applicable Metering Adjustments.

Credit for EPRI Contributions:

A credit of six cents ($0.06) per kilowatt of the demand component will be allowed to all customers served under this schedule with the exception of the Company's affiliated customers (Massachusetts Electric Company, Narragansett Electric Company and Granite State Electric Company) in order to reflect the Company's commitment to research support of the Electric Power Research Institute (EPRI) unless a customer notifies the Company in writing that it desires to contribute through the Company's commitment, in which event this credit shall not apply to such Customer. In accordance with a Settlement Agreement in Docket Nos. ER91-565, et al., the credit applicable to the Town of Norwood will be nine cents ($0.09) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. These credits shall be computed after the application of any applicable Metering Adjustments and at the point of delivery which enters into the computation of the Customer's Demand for the month in question.

Norwood Yankee: Surcharge:	In accordance with the terms of the W-12 Settlement Amendment dated December 17, 1992 in Docket No. ER90-525 et al., NEP shall apply a monthly surcharge to the Town of Norwood, equal to the amounts calculated in accordance with that settlement.
Norwood Seabrook 1 Amortization Surcharge:	In accordance with the terms of the W-95(N) Settlement dated June 30, 1995 in Docket No. ER95-267 et al., NEP shall apply a monthly surcharge to the Town of Norwood, equal to the amounts calculated in accordance with section 2.2(b) of that settlement.

The Company reserves the right to amend the foregoing rate in the manner set forth in its General Terms and Conditions governing primary service for resale in Schedule I.

Effective Date: July 12, 1995

NEW ENGLAND POWER COMPANY

Primary Service for Resale

DETERMINATION OF CONTRACT TERMINATION CHARGE
UNDER EARLY TERMINATION PROVISION

A. Applicability

The terms and conditions of this Schedule II-C are applicable to any eligible all-requirements wholesale customer ("Customer") of New England Power Company ("Company") under this tariff which elects the early termination option under Schedule I, Section N of this tariff.

B. Determination of Contract Termination Charge

If a Customer exercises the early termination option under Schedule I, Section N, paragraph 2, of this tariff, the Customer shall pay the Company a Contract Termination Charge ("CTC") as determined under this schedule. The CTC shall be determined as follows:

$$CTC = (R - M) \times L$$

where:

R	=	the Customer's Annual Average Revenue, as determined in Section 1 below;
M	=	the Estimated Market Value of the Customer's released capacity and associated energy, as determined under Section 2 below;
L	=	the Length of Obligation in years, as determined under Section 3 below;

Payment of the CTC by the Customer shall be in accordance with Schedule I, Section N, paragraph 2, of this tariff.

The CRC shall be determined on a net present value basis, with the difference between R and M discounted to the Early Termination Date as defined in Section 3 below. The discount rate used shall equal the rate determined pursuant to section 35.19a of the Commission's regulations (18 C.F.R. § 35.19a) effective on the Early Termination Date.

In no event shall the CTC exceed the amount determined under section 4 below.

1. R – Average Annual Revenue

The Customer's Annual Average Revenue shall equal the Total Revenue minus the Transmission Revenue.

a. *Total Revenue* shall equal the annual average of revenues received by the Company from the Customer over three years under the presently effective rates as shown on Schedule II-A and Schedule II-B of this tariff. The three-year period shall be the 36 months immediately prior to the Early Termination Date as specified by the Customer under the second paragraph of Schedule I, Section N of this tariff. In the event that the rates paid by the Customer under Schedule II-A or Schedule II-B of this tariff have changed during the three-year period, Total Revenue shall be determined using the Customer's revenue for the 12 months immediately prior to the Early Termination Date. The Company at its discretion may use estimates of the Customer's billing units for determining Total Revenue, such estimates to be reconciled to actual billing units within six months after the Early Termination Date. The calculation of Total Revenue shall include credits pursuant to Schedule III-D of this tariff as well as all credits and surcharges applicable to the Customer under the Customer's Service Agreement with the Company under this tariff, with the exception of credits associated with Integrated Facilities arrangements under Schedule III-B of this tariff and any credits associated with the Company's reimbursement of the Customer's payments to third parties for transmission service.

b. *Transmission Revenue* shall equal the sum of: (i) the annual average of revenues the Company credited to the Customer with respect to payments made by the Customer to third parties for transmission service pursuant to any applicable provision of the service agreement between the Company and the Customer; or (ii) if the service agreement does not provide for such credits, the annual average of revenues the Company would have received from the Customer using the presently effective rates under the Company's Open Access Transmission Tariff, FERC Electric Tariff Original Volume No. 9 ("Tariff No. 9"); and (iii) the annual average of payments made by the Company to the New England Power Pool ("NEPOOL") for transmission service on the Customer's behalf under NEPOOL's Open Access Transmission Tariff, all as determined during the period over which the Total Revenue is determined. The Company at its discretion may use estimates of the Customer's billing units for determining Transmission Revenue, such estimates to be reconciled to actual billing units within six months after the Early Termination Date.

2. <u>M – Estimated Market Value</u>

The Estimated Market Value shall equal the annual average of the Market Price Estimate for each year of the Length of Obligation (as determined pursuant to Section 3 below) multiplied by the Customer's Released Load.

a. *Market Price Estimate* shall equal the per kilowatt-hour amount set forth in the Table below, as in effect on the Early Termination Date, as applicable to each year during the Length of Obligation. The Market Price Estimate shall include both a capacity-related and energy-related component.

Year	Capacity (¢/kWh)	Energy (¢/kWh)	Total (¢/kWh)
1998	1.10	2.71	3.81
1999	1.22	2.64	3.86
2000	1.22	2.66	3.88
2001	1.25	2.61	3.86
2002	1.31	2.63	3.94
2003	1.34	2.71	4.05
2004	1.40	2.72	4.12
2005	1.44	2.77	4.21
2006	1.47	2.86	4.33
2007	1.53	2.95	4.48
2008 forward		prices for 2007 escalated at 2% annually	

b. *Released Load* shall equal the annual average of the Customer’s kilowatt-hour purchases from the Company for the period over which Total Revenue is determined. The Company at its discretion may use estimates of the Customer’s kilowatt-hour purchases for determining Released Load, such estimates to be reconciled to actual purchases within six months after the Early Termination Date.

3. L – Length of Obligation

The Length of Obligation shall equal the time period between the Early Termination Date and the Regular Termination Date.

a. *Early Termination Date* shall be as determined under Schedule I, Section N, paragraph 2 of this tariff

b. *Regular Termination Date* shall be the date at which the Company or the Customer could have unilaterally terminated service under Schedule I, Section N, paragraph 1 of this tariff and any applicable provisions of the Customer’s Service Agreement with the Company under this tariff.

4. Maximum Contract Termination Charge

In no event shall the difference between R and M (as determined in Sections 1 and 2 above) exceed the Customer’s annual contribution to the Company’s fixed power supply costs under this tariff. The Customer’s annual contribution to the company’s fixed power supply costs shall equal its Total Revenue minus Transmission Revenue minus the Company’s Average Fuel Costs. Average Fuel Costs shall equal the annual average of revenues the Company recovered for its Cost of Fuel as defined in Schedule II-A of this tariff multiplied by the Customer’s monthly kilowatt-hour purchases during the period over which Total Revenue is determined in Section 1 above.

NEW ENGLAND POWER COMPANY

Schedule III-A

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NEW ENGLAND POWER COMPANY

Primary Service for Resale

TERMS AND CONDITIONS

governing

ALL-REQUIREMENTS SERVICE - INTEGRATED FACILITIES

Schedule III-B

A. Applicability

The terms and conditions set forth herein shall apply when the Service Agreement is between the Company and a Customer which is affiliated with the New England Power Company, and specifies All-Requirements Service - Integrated Facilities.

B. Integrated facilities: Obligations of the parties.

Recognizing that the generation and transmission facilities owned by the Company and the Customer are physically interconnected and can be operated to achieve maximum economy through integrated operation, the Customer and the Company agree as follows:

1. The Customer will operate and maintain its generating and transmission facilities in accordance with standards fixed from time to time by the Company, and will make available to the Company the full capacity of such facilities to meet the load of the integrated generating and transmission system (consisting of the generating and transmission facilities owned by the Company and affiliated companies of the New England Power Company). The Company and the Customer may agree to exclude from the facilities made available as aforesaid any facilities deemed not to be necessary or feasible for integration, and such excluded facilities shall not be considered part of the integrated generating and transmission system as defined above.

2. The generating and transmission facilities of the Customer made available to the Company under paragraph 1 shall be subject to dispatch by the Company to meet the load of the integrated generating and transmission system, and the output of the Customer's generating units so dispatched shall be deemed to be for the account of the Company. The Customer will conform to maintenance schedules fixed by the Company to ensure maximum availability of capacity.

3. The Company and the customers whose facilities constitute a part of the integrated generating and transmission system will plan jointly for the future requirements of such system. The Customer agrees to make additions to and retirements of its generating and transmission facilities in accordance with

schedules fixed from time to time by the Company.

4. In consideration of the foregoing, the Company assumes responsibility for the supply of the electrical requirements of the Customer from the integrated generating and transmission system, including transmission losses over such system, and agrees to credit the Customer for the use of its generating and transmission facilities, in accordance with the following provisions:

   a. The Company agrees to sell and the Customer agrees to buy, at the Company's effective rate for primary service for resale, the Customer's entire requirements of electricity for its own use and for resale within the Districts described in the Service Agreement, with the following exceptions: (1) electricity purchased by the Customer from commercial and industrial establishments located within any District of the Customer's service area and specified in the Service Agreement, (2) electricity purchased by the Customer under convenience contracts for the supply of electricity to borderline customers, and (3) such other exceptions as may be mutually agreed upon between the parties and set forth in the Service Agreement.

   b. For Customer-owned Transmission Plant, the Company will credit each monthly bill rendered to the Customer using the calculation shown below based on the previous month's cost data from Customer's official books and records. Capitalized terms used in this calculation will have the following definitions:

      1. Gross Transmission Plant Allocation Factor shall equal the ratio of Customer's Total Investment in Transmission Plant to Total Plant in Service, excluding General Plant.

      2. PTF Allocation Factor shall equal the ratio of PTF Transmission Plant to Transmission Plant.

      3. PTF-RSP Allocation Factor shall equal the ratio of PTF-RSP Transmission Plant to Transmission Plant.

      4. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct electric wages and salaries from Customer to Customer's total electric direct wages and salaries and excluding electric administrative and general wages and salaries.

      5. Administrative and General Expense shall equal Customer's electric expenses as recorded in FERC Account Nos. 920-935, less Post Employment Benefits Other than Pensions ("PBOP") included in FERC Account 926, plus the FERC-accepted Post Employment

Benefit Other than Pensions identified in each Customer’s Service Agreement or any other amount subsequently approved by FERC under Section 205 of the Federal Power Act.

6. Amortization of Investment Tax Credits shall equal Customer's electric credits as recorded in FERC Account No. 411.4.

7. Amortization of Loss on Reacquired Debt shall equal Customer's electric expenses as recorded in FERC Account No. 428.1.

8. Depreciation Expense for Transmission Plant shall equal Customer's electric transmission plant related depreciation expenses as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in each Customer’s Service Agreement.

9. General Plant shall equal Customer's electric gross general plant balance as recorded in FERC Account Nos. 389-399.

10. General Plant Depreciation Expense shall equal Customer's electric general plant related depreciation expenses as recorded in FERC Account No. 403.

11. General Plant Depreciation Reserve shall equal Customer's electric general plant depreciation reserve balance as recorded in FERC Account No. 108.

12. Municipal Tax Expenses shall equal Customer's electric transmission-related municipal tax expense as recorded in FERC Account No. 408.1.

13. Payroll Taxes shall equal those electric payroll tax expenses as recorded in Customer's FERC Account Nos. 408.1.

14. Land Held for Future Use shall equal the Customer's electric transmission-related balance for Land in FERC Account No. 105.

15. Prepayments shall equal Customer's electric prepayment balance as recorded in FERC Account No. 165.

16. PTF-RSP Transmission Plant shall equal any PTF Transmission Plant as defined below and approved as part of the ISO-NE Regional System Plan.

17. PTF Transmission Plant shall equal electric transmission plant as defined in Section II.49 of the ISO-NE OATT and determined in

accordance with Appendix A of Attachment F Implementation Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

18. Total Accumulated Deferred Income Taxes shall equal the net of Customer's electric deferred tax balance as recorded in FERC Account Nos. 281-283 and Customer's electric deferred tax balance as recorded in FERC Account No. 190, all excluding associated FAS 109 Accumulated Deferred Income Taxes and any Accumulated Deferred Income Taxes associated with pension-related regulatory assets or liabilities.

19. Total Loss on Reacquired Debt shall equal Customer's electric expenses as recorded in FERC Account 189.

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

21. Total Transmission Depreciation Reserve shall equal Customer's electric transmission plant related depreciation reserve balance as recorded in FERC Account 108.

22. Transmission Operation and Maintenance Expense shall equal Customer's electric expenses as recorded in FERC Account Nos. 560-564 and 566-573 less any expenses recorded in FERC Accounts 561.4 and 561.8.

23. Transmission Plant shall equal Customer's electric gross plant balance as recorded in FERC Account Nos. 350-359.

24. Transmission Plant Materials and Supplies shall equal Customer's electric materials and supplies balance as recorded in FERC Account No. 154.

25. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided which is not specifically identified under any other section contained herein.

In the event that the above-referenced FERC accounts are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

Calculation of Transmission Revenue Requirements

The monthly Transmission Revenue Requirement shall equal the sum of Customer’s (A) Return and Associated Income Taxes (including the Incremental Returns for PTF-RSP and PTF Investment), (B) Transmission Depreciation 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) Direct Assignment Facilities Credit, (J) Transmission Related Taxes and Fees Charge, (K) Billing Adjustments, and (L) Annual True-Up Adjustment. The Incremental Return and Associated Income Taxes for PTF-RSP and PTF Investments 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 each of the Transmission Investment Base (PTF-RSP, PTF and Non-PTF, respectively) and the Cost of Capital Rates applicable to each.

1. Transmission Investment Base

(a) Total Transmission Investment Base shall be defined as a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, plus (d) Transmission Related Construction Work In Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital.

(i) PTF-RSP Investment Base will be the monthly balances of PTF-RSP Transmission Plant, less the sum of (d) Transmission Related Depreciation Reserve and (e) Transmission Related Accumulated Deferred Income Taxes, multiplied by the PTF-RSP Allocation Factor.

(ii) PTF Transmission Investment Base will be the monthly balances of PTF Transmission Plant, less PTF-RSP Investment Base, plus the product of: PTF Allocation Factor multiplied by the sum of the [(b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Income Taxes, plus (f) Transmission Related Loss on Reacquired Debt, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital].

(iii) Non-PTF Transmission Investment Base shall equal Total

Transmission Investment Base less PTF-RSP Investment Base less PTF Investment Base.

(b) Transmission Related General Plant shall equal Customer's balance of investment in electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Land Held for Future Use shall equal Customer's balance of electric Transmission-related Land Held for Future Use.

(d) Transmission Related Construction Work In Progress shall equal the portion of Customer's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal Customer's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Related Accumulated Deferred Income Taxes shall equal Customer's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Gross Transmission Plant Allocation Factor.

(g) Transmission Related Loss on Reacquired Debt shall equal Customer's electric balance of Total Loss on Reacquired Debt multiplied by the Gross Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal Customer's electric balance of prepayments multiplied by the Gross Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal Customer's electric balance of Transmission Plant Materials and Supplies, multiplied by the Gross Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Customer's Transmission Operation and Maintenance Expense and Transmission-Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will incorporate Customer's imputed capital structure, Customer's actual cost of long-term debt and preferred equity, and approved ROEs for Transmission Investment Bases (PTF-RSP, PTF and Non-PTF, respectively), plus Federal Income Tax and State Income Tax, as applicable.

a) The Weighted Costs of Capital will be calculated for each of the Transmission Investment Bases (PTF-RSP, PTF and Non-PTF, respectively) based upon the imputed capital structure for Customer in place in accordance with Rhode Island Docket Nos. 2930 and 3617 and will equal the sum of (i), (ii), and each ROE applied in item (iii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of Customer's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45%.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Customer's preferred stock then outstanding and the imputed preferred stock capitalization ratio of 5%.

(iii) the return on equity component (ROE), shall be the product of the allowed ROEs applicable to the corresponding investments below and the Customer's imputed common equity capitalization ratio of 50% consistent with FERC's Order on Rehearing issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and FERC Opinion Nos. 531-A and 531-B issued in Docket No. EL11-66-000 et al., plus any additional incentive ROE adders as may be applied to specific investment approved by the FERC in response to requests for such adders filed by NEP pursuant to Order No. 679, 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 of 11.74% effective as of October 16, 2014, consistent with FERC Opinion Nos. 531-A and 531-B. To the extent FERC modifies ROEs as applicable to transmission services under the ISO New England Open Access Transmission Tariff, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to a filing with FERC under Section 205 of the Federal Power Act.

11.74% - Post-2003 to pre-2009 PTF transmission plant investment included in the Regional System Plan approved by ISO-NE.

11.07% - The remaining PTF transmission plan investment.

10.57% - The remaining transmission plant investment.

(b) Federal Income Tax applied shall equal

$$\frac{(PS + ROE) \quad x \quad \text{Federal Income Tax Rate}}{(1\text{- Federal Income Tax Rate})}$$

where PS is the Preferred Stock Component and ROE is the return on equity component, each as determined in Sections 2.(a)(ii) and for the applied ROEs set forth in 2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{((PS+ROE) + \text{Federal Income Tax}) \text{ x State Income Tax Rate}}{1 - \text{State Income Tax Rate}}$$

where PS is the Preferred Stock Component and ROE is the return on equity component in Section 2.(a)(ii) and Section 2.(a)(iii) above, Federal Income Tax is Federal Income Tax as determined in Section 2.(b) above.

B. Transmission Depreciation Expense shall equal Customer’s electric Depreciation Expense for Transmission Plant, plus an allocation of electric General Plant Depreciation Expense calculated by multiplying electric General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Customer's electric Amortization of Loss on Reacquired Debt multiplied by the Gross Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal Customer's electric Amortization of Investment Tax Credits multiplied by the Gross Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal Customer's transmission-related electric municipal tax expense.

F. Transmission Related Payroll Tax Expense shall equal Customer's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Customer's total electric Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of Customer's electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor.

I. Direct Assignment Facilities Credit shall equal the monthly revenue received by NEP for service provided to any of NEP's wholesale customers that utilize directly assigned transmission, distribution and/or generator interconnection facilities owned by Customer. Such NEP revenue is defined as any revenue NEP receives for Direct Assignment Facilities under the ISO-NE OATT or any interconnection-related charges for Customer-owned and/or maintained facilities under FERC jurisdictional agreements where NEP is the party to the agreement.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this section, including, but not limited to, expenses incurred by the Customer related to third party independent audits conducted at the request of any governmental authority, and any other fee or assessment which is not specifically identified under any other section contained herein. Such costs will be separately identified and included in item H - Administrative and General Expense, above.

K. Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods. Billing adjustments shall include, but not be limited to, adjustments due to corrections to any value included in this formula, including, but not limited to, corrections to the FERC Form 1.

L. Annual True-Up Adjustment

1. NEP shall submit an annual informational filing with the FERC with copies to state commissions and attorneys general in the state of any affected Customer reconciling monthly billings to Customer under this formula to data supplied from Customer's Quarterly FERC Form 1 (the "Annual True- up"). The Annual True-up will be completed no later than (3) months after Customer issues its final 4th Quarter FERC Form 1 for the calendar year which the Annual True-up relates (the "Service Year"). The Annual True-up will reconcile any differences between a recalculation of the costs for the Service Year based on actual data reported in Customer's Quarterly FERC Form l's as compared to the monthly actual costs invoiced. The recalculation of the costs for the Service Year will be done using the average quarterly balances for all

balance sheet items used in the formula (i.e. Plant, Depreciation Reserve, Deferred Taxes). Expenses will be those Service Year expenses reported in Customer's 4th Quarter FERC Form 1.

2. The difference, if any, between the monthly actual costs invoiced to Customer during the Service Year and the annual revenue requirement based on actual FERC Form 1 data shall be reflected as an adjustment to the monthly revenue requirement calculation for the month following the month in which the Annual True-Up report is issued (the "Annual True-up Adjustment").

3. If the recalculation of costs for the Service Year using FERC Form 1 data exceeds the monthly billed amounts for the Service Year, the Annual True-up Adjustment will be an additional credit to Customer. If the monthly billed amounts for the Service Year exceed the recalculation of costs using FERC Form 1, the Annual True-up Adjustment will be a reduction to the credit to Customer. The Annual True-up Adjustment will be adjusted for interest, whether positive or negative, accrued monthly from December 31 of the Service Year to the end of the calendar month in which the Annual True-up Adjustment will be applied to a monthly billing. Interest shall accrue pursuant to the rate specified in the Commission's regulations 18 C.F.R §35.19a.

4. Any changes to the data inputs, including but not limited to revisions to Customer's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual True-up, or as a result of the procedures set forth herein not otherwise captured as part of ongoing Billing Adjustments, shall be incorporated into the formula rate and the charges produced by the formula rate (with interest determined in accordance with 18 C.F.R. § 35.19a) in the Annual True-up for the next effective rate period.

5. In any proceeding before the FERC concerning the Annual True-up, the Company shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate. Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence challenges.

M. Five-Year Forecast

The Company’s annual informational filing will also provide a report containing a five year forecast of anticipated transmission capital expenditures by the Company and its Customers taking service under this Tariff that will, upon completion of projects, be included in transmission rates. The forecast will also include the estimated retail rate impacts for each of the Company’s respective Customers under this Schedule III-B.

N. Audit Provisions

1. There will be an "Audit Period" that will extend from the date the informational filing is filed with FERC through December 31 of the year following the Service Year. At any time during the Audit Period, a Customer shall have the right to request an audit or conduct an inspection of the actual data used in the Annual True-Up and any and all transmission charges or credits billed by Company during the Service Year. Subject to the limitation that the Attorneys General of Massachusetts and Rhode Island do not make or receive transmission payments or refunds, they shall have the same procedural rights under this Section as a Customer. Company shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel as prescribed by FERC. Company is not obligated to disclose privileged information or information protected by the attorney work product doctrine. Company shall exercise all commercially reasonable efforts to provide Customer, within 10 business days, such additional information as Customer may reasonably request. To the extent requested, Company shall meet with any Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up or any other information related to Customer billing under this Tariff during the Service Year. During the Audit Period any Customer may request that Company adjust the Annual True-up Adjustment and/or Customer bills rendered during the Service Year. Any adjustment that Company agrees to make may be reflected in the next month following such adjustment. Upon request of any Customer during the Audit Period, Company shall engage a third party independent auditor (the "Auditing Entity") through the process described in Paragraph 4, below. The Auditing Entity shall certify that the development, accuracy and application of data, is in accordance with the provisions of this Tariff. The Auditing Entity shall provide a Certified Public Accountant's attestation setting forth such certification ("CPA Attestation").

2. In addition to the CPA Attestation, the Auditing Entity will provide an audit report that will specify the audit process and procedures; identify the individual auditors and their functions; and include all copies of all written communications with Company personnel, summaries of all other communications related to the audit, descriptions of all data analysis techniques used, findings and recommendations. Also, the Auditing Entity shall make available all workpapers and other documentation and materials that support the CPA Attestation.

3. Company shall engage the Auditing Entity to perform the CPA Attestation duties through a competitive bidding process, evaluating each bidder

according to cost, experience, competency and familiarity with the industry and the regulatory environment. The requesting Customer(s) shall have the right to approve the content of the Request for Proposal and Company's selection of the auditing entity, which approval shall not be unreasonably withheld. If necessary, and after good faith efforts have not resulted in the Company's obtaining an Auditing Entity to provide the CPA Attestation pursuant to this Paragraph 4, the requesting Customer(s) and the Company agree to negotiate in good faith the scope of work that may be needed to provide a CPA Attestation and to accommodate the American Institute of Certified Public Accountants Code of Professional Conduct.

4. In the event an independent audit is performed with respect to a Service Year and the Company determines that the Annual True-Up is incorrect, the Annual True-Up required by Paragraph L of this Tariff may be subsequently adjusted pursuant to the provisions of this Tariff.

5. The reasonable and prudent cost of the Auditing Entity's services and Company's reasonable and prudent costs of engaging the Auditing Entity and providing information to the Auditing Entity and the Customer shall be included as part of the transmission costs charged to the Customers under this Tariff.

Formula rate inputs for rate of return on common equity, depreciation rates and Post-Employment Benefits Other than Pensions (PBOP) shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission. Application under Section 205 or 206 to modify stated values for depreciation rates or PBOP expense under the formula rate shall not open review of other components of the formula rate.

Calculation of Primary Distribution Revenue Requirements

For Customer-owned distribution facilities utilized by the Company for purposes of providing wholesale transmission service, effective as of the June billing month of each year , the Company will credit each monthly bill rendered to the Customer with one-twelfth of the annual costs determined by multiplying the sum of the applicable Customer's: (i) Distribution Plant Assets; (ii) Shared Substation Assets, and; (iii) Buildings and Facilities, each as set forth in the Customer's Service Agreement, by the Primary Distribution Carrying Charge based upon previous calendar year data. The Primary Distribution Carrying Charge shall be calculated as follows for the applicable Customer:

I. The Primary Distribution System Carrying Charge shall be calculated annually based on actual calendar year data as reported in the FERC Form 1 and shall equal the sum of (A) Return and Associated Income Taxes, (B) Primary Depreciation Expense, (C) Primary Related Amortization of Loss on Reacquired Debt, (D) Primary Related Amortization of Investment Tax Credits, (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, (G) Primary Related Administrative and General Expense, and (H) Primary Revenue Credit, divided by Total Primary Distribution Plant.

A. Return and Associated Income Taxes shall equal the product of the Primary Investment Base and the Cost of Capital Rate.

1. Primary Investment Base

Primary Investment Base will be (a) Primary Distribution Plant, plus (b) Primary Related General Plant, plus (c) Primary Plant Held for Future Use, less (d) Primary Depreciation Reserve, less (e) Primary Related Accumulated Deferred Income Taxes, plus (f) Primary Related Loss on Reacquired Debt, plus (g) Primary Materials and Supplies, plus (h) Primary Related Prepayments, plus (i) Primary Related Cash Working Capital.

a) Primary Distribution Plant shall equal the Customer's Plant Accounts 360 to 373 multiplied by allocation factors from the Distribution Allocation Study.

b) Primary Related General Plant shall equal the Customer's Investment in General Plant excluding investment in specific buildings and facilities allocated to Company, multiplied by the Primary Wages & Salaries Allocation Factor. The Primary Wages & Salaries Allocation Factor shall equal the ratio of Total Distribution Wages & Salaries to the Total Customer's Wages & Salaries excluding A&G, multiplied by the ratio of Primary Distribution related O&M to Total Distribution O&M (Primary O&M Allocation Factor).

c) Primary Plant Held for Future Use shall equal the

Customer's Account 105, multiplied by the Primary Land Allocation Factor from the Distribution Allocation Study.

d) Primary Depreciation Reserve shall equal the Customer's Depreciation Reserve multiplied by the ratio of Primary Depreciable Distribution Plant to Total Depreciable Distribution Plant (Primary Depreciable Plant Allocation Factor), plus an allocation of average General Plant Depreciation Reserve calculated by multiplying beginning and end of year General Plant Depreciation Reserve by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above,

e) Primary Related Accumulated Deferred Income Taxes shall equal the Total Accumulated Deferred Income Taxes, multiplied by the ratio of average Primary Plant in Service to average Total Plant in Service excluding General Plant (Primary Plant Allocation Factor).

f) Primary Related Loss on Reacquired Debt shall equal the Total Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

g) Primary Materials and Supplies shall equal the Customer's Distribution Plant Materials and Supplies, multiplied by the Primary O&M Allocation Factor as described in Section (I)(A)(1)(b) above.

h) Primary Related Prepayments shall equal the Customer's Prepayments, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b) above.

i) Primary Related Cash Working Capital shall be a 45 day allowance or 12.5% of Primary Operation and Maintenance Expense and Primary Related Administrative and General Expense.

2. Cost of Capital Rate

Cost of Capital Rate will equal (a) the Customer'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) the long-term debt component, which equals the product of the actual dollar weighted average embedded cost to maturity of the Customer's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45 percent.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the Customer's preferred stock then outstanding and the Imputed preferred stock capitalization ratio of 5 percent.

(iii) the return on equity component (ROE), shall be the product of the allowed ROEs of 10.57% as per FERC's Order on Rehearing Issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and FERC Opinion Nos. 531-A and 531-B issued in Docket No. EL11-66-000 et al. and Customer's imputed common equity capitalization ratio of 50%, plus any additional incentive ROE adders as may be applied to specific investment approved by the FERC in response to requests for such adders filed by NEP pursuant to Order No. 679, 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 of 11.74% effective as of October 16, 2014, consistent with FERC Opinion Nos. 531-A and 531-B. To the extent FERC modifies ROEs as applicable to transmission services under the ISO New England Open Access Transmission Tariff, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to a filing with FERC under Section 205 of the Federal Power Act.

b) Federal Income Tax shall equal

$$\frac{\text{A x Federal Income Tax Rate}}{\text{1- Federal Income Tax Rate}}$$

where A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii)
above.

c) State Income Tax shall equal

$$\frac{\text{(A + Federal Income Tax) x State Income Tax Rate}}{\text{1 – State Income Tax Rate}}$$

where A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is the Federal Income Tax as determined in Section (I)(A)(2)(b) above.

B. Primary Depreciation Expense shall equal Customer's electric distribution-related depreciation expense as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in each Customer's Service Agreement, multiplied by the Primary Depreciable Plant Allocation Factor as described in Section (I)(A)(1)(d) above, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(l)(b) above.

C. Primary Related Amortization of Loss on Reacquired Debt shall equal the Customer's Amortization of Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

D. Primary Related Amortization of Investment Tax Credits shall equal the Customer's Amortization of Investment Tax Credits, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(I)(e) above.

E. Primary Related Municipal Tax Expense shall equal a pro-rata share of the Customer's total municipal taxes allocated by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

F. Primary Operation and Maintenance Expense shall the sum of all expenses charged to FERC Account Numbers 580 through 598, allocated to Primary as indicated by the Distribution Allocation Study.

G. Primary Related Administrative and General Expenses shall equal the Customer's Administrative and General Expenses, plus Payroll Taxes, multiplied by the Primary Wages & Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

H. Primary Related Revenue Credit shall equal Customer's Other Operating Revenues excluding any revenues from network distribution transactions, multiplied by the Primary O&M Allocation Factor as defined in (I)(A)(1)(b).

For Company-owned facilities utilized by the Customer for purposes of providing retail distribution service, effective as of the June billing month of each year, the Company will net from the Primary Distribution Revenue Requirement credit applied to each monthly bill rendered to the Customer one-twelfth of Company's annual costs determined by multiplying the sum of the Company's: (i) Transmission Assets (ii) Distribution Plant Assets; (iii) Shared Substation Assets, and; (iv) Buildings and Facilities, each as set forth in the Customer's Service Agreement, by the Annual Facilities Carrying Charge for Transmission Facilities - based upon previous calendar year data. In addition, the Company will net from the Primary Distribution Revenue Requirement credit applied to each monthly bill rendered to the Customer one-twelfth of

Company's annual cost for pole and tower attachments. The Annual Facilities Charge for Transmission Facilities shall be calculated as follows:

1. The Annual Facilities Carrying Charge for Transmission Facilities shall be calculated annually based on actual calendar year data as reported in the FERC Form 1 and shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation 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 Operation and Maintenance Expense, and (G) Transmission Related Administrative and General Expenses, divided by Total Transmission Plant.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

Transmission Investment Base will be (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission-related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Income Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Related Materials and Supplies, less (i) Allowance for Funds Used During Construction (AFUDC) Regulatory Liability, plus (j) Transmission Related Prepayments, plus (k) Transmission Related Cash Working Capital.

a) Transmission Plant shall equal NEP's balance of Total Investment in Transmission Plant in FERC Accounts 350 - 359, plus NEP's Total Investment in Distribution Plant in FERC Accounts 360-369 excluding NEP's capital leases in the Hydro-Quebec DC facilities (HQ leases).

b) Transmission Related General Plant shall equal NEP's balance of investment in General Plant in FERC Accounts 389 to 399 excluding General Plant related to NEP's generation facilities.

c) Transmission Plant Held for Future Use shall equal the balance of investment in FERC account 105 excluding generation-related plant held for future use.

d) Transmission Related Construction Work in Progress shall equal the portion of NEP's investment in Transmission related projects as recorded in FERC Account 107 consistent with Commission Orders.

e) Transmission Related Depreciation Reserve shall equal the balance of Total Depreciation Reserve in FERC Account 108, excluding any generation-related depreciation reserve.

f) Transmission Related Accumulated Deferred Income Taxes shall equal the net of NEP's Total Accumulated Deferred Income Taxes in FERC Accounts 281-283 and FERC Account 190, all excluding associated FAS 109 Accumulated Deferred Income Taxes and any Accumulated Deferred Income Taxes associated with pension-related regulatory assets or liabilities and any Accumulated Deferred Taxes associated with non-utility assets or generation facilities.

g) Transmission Related Loss on Reacquired Debt shall equal NEP's balance of Total Loss on Reacquired Debt in FERC Account 189.

h) Transmission Related Materials and Supplies shall equal NEP's balance of Materials and Supplies in FERC Account 154.

i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission Orders.

j) Transmission Related Prepayments shall equal NEP's balance of prepayments in FERC Account 165 excluding any prepayments related to NEP's ongoing generation-related activities.

k) Transmission Related Cash Working Capital shall be 12.5% allowance (45 days/360) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate shall equal (a) NEP's Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) 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) the long-term debt component, which equals the product of the actual dollar weighted average embedded cost to maturity of NEP's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45 percent.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NEP's preferred stock then outstanding and the imputed preferred stock capitalization ratio of 5 percent.

(iii) the return on equity component (ROE) shall be the product of 10.57% as per FERC's Order on Rehearing issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and FERC Opinion Nos. 531-A and 531-B issued in Docket No. EL11-66-000 et al., and NEP's imputed common equity capitalization ratio of 50%. To the extent FERC modifies ROEs as applicable to transmission services under the ISO New England Open Access Transmission Tariff, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to the filing with FERC under Section 205 of the Federal Power Act.

b) Federal Income Tax shall equal

$$\frac{\text{A x Federal Income Tax Rate}}{\text{1- Federal Income Tax Rate}}$$

Where A is the sum of the preferred stock component and the return on equity component determined in Section (1)(A)(2)(a)(ii) and Section (1)(A)(2)(a)(iii) above.

c) State Income Tax shall equal

$$\frac{\text{(A + Federal Income Tax) x State Income Tax Rate}}{\text{1 – State Income Tax Rate}}$$

Where A is the sum of the preferred stock component and the return on equity component determined in Section (1)(A)(2)(a)(ii) and Section (1)(A)(2)(a)(iii) above, and the Federal Income Tax is Federal Income Tax as determined in Section (1)(A)(2)(b) above.

B. Transmission Related Depreciation Expense shall equal the Depreciation Expense in FERC Account 403 associated with Transmission Plant, Transmission Related General Plant and Transmission Plant Held for Future Use as described in Sections (1)(A)(1)(a),(b) and (c), less the amortization of AFUDC Regulatory

Liability as recorded in FERC Account 407.3.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal NEP's amortization of the balance on Loss on Reacquired Debt recorded in FERC Account 428.1.

D. Transmission Related Amortization of Investment Tax Credits shall equal the amortization of Investment Tax Credits recorded in FERC Account 411.4, excluding any ITC credits specifically identified as generation-related.

E. Transmission Related Municipal Tax Expense shall equal NEP's total municipal tax expense recorded in FERC Account 408.1 excluding specifically identified generation-related municipal taxes or payments in lieu of such generation-related municipal taxes.

F. Transmission Operation and Maintenance Expense shall equal all expenses charged to FERC Account Numbers 560 through 598. Account Number 565, Transmission by Others, shall only include those expenses in support of facilities that are integrated with NEP's Transmission System or other transmission systems.

G. Transmission Related Administrative and General Expenses shall equal NEP's Administrative and General Expenses recorded in FERC Accounts 920-935, less production-related Administrative and General Expenses associated with joint-owned production units, plus Payroll Taxes.

The Company's rate for tower attachments is $49.28 per tower. The Company's rate for pole attachments is $253.27 per pole. The annual cost for the Customer to attach to the Company's towers and poles will be the product of the respective rate multiplied by the number of respective attachments as specified in the Customer's Service Agreement.

The Customer shall afford to the Company the opportunity at any time to make such reasonable examination of the Customer's books and records as the Company may request for the purpose of verifying the basis for calculation of the foregoing monthly credits.

The foregoing credits shall be reviewed annually and upon substantial addition, modification or retirement of the Customer's generating and transmission facilities or other substantial change in circumstances, any changes therein shall be reflected in a revised Service Agreement.

C. <u>Service Agreement Amendments.</u>

If the Service Agreement is amended by mutual consent of the parties, the terms of the agreement as so amended shall be applicable to the Customer's service on and after the effective date specified therein. If no such amendment has been executed prior to the date specified in the Customer's notice, the Customer may at its election terminate the Service Agreement forthwith or upon such date within the following twelve months as it may specify to the Company in writing.

D. Tariff Amendments.

The Company reserves the right to amend the foregoing terms and conditions in the manner set forth in its General Terms and Conditions governing primary service for resale.

NEW ENGLAND POWER COMPANY

Schedule III-C

THIS SECTION INTENTIONALLY LEFT BLANK

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and Transmission Service
for Partial Requirements Customers

FORM OF SERVICE AGREEMENT

Dated:

Parties: NEW ENGLAND POWER COMPANY
A Massachusetts corporation (the "Company")

20 Turnpike Road
Westborough, Massachusetts 01581

and

(the "Customer")

1. Scope of Service Agreement. The Company agrees to sell and transmit and the Customer agrees to buy Primary Service for Resale on the terms set forth in the following Schedules as in effect from time to time:

Schedule I	- General Terms and Conditions
Schedule II	- Rate Provisions
Schedule III	- Terms and Conditions Governing Service

These Schedules and Appendix A to this Service Agreement are expressly included as part of this Agreement.

2. Prior agreements. As of the date of commencement of service hereunder, this Service Agreement shall supersede and cancel all prior contracts between the parties for the type(s) of service specified herein with the following exceptions:

WITNESS the corporate names of the parties, by their proper officers thereunto duly authorized, as of the date first above written.

Executed in duplicate.

NEW ENGLAND POWER COMPANY

By ________________________________
Vice-President

APPENDIX A

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers

1. Name of Customer:

2. Name of District:

3. Service Under:

4. Electric Utilities Served by the Customer as of the date of the Service Agreement:
(Schedule I - Paragraph D)

5. Electricity Purchased from Commercial and Industrial Establishments by the Customer as of the date of the Service Agreement:
(Schedule I - Paragraph D)

6. Variations from Standard Delivery and Metering:
(Schedule I - Paragraph G, 5)

7. Entitlements:
   A. On Customer System
      (Schedule III-C - Paragraph C.2.(a))
   B. Off Customer System
      (Schedule III-C - Paragraph C.2.(b))

8. Customer Generation excluded from

Firm Capacity Calculation:

(Schedule III-C - Paragraph C.3.c)

9. Firm Capacity:

(Schedule III-C - Paragraph C.3.c)

10. Integrated Generating, Transmission and Facilities Credits Payable by Company:

(Schedule III-B - Paragraph B.4.b)

11. Primary Service for Resale:

Delivery Points	Delivery Pressure KV (Nominal)	Metering Points	Metering Pressure KV (Nominal)	Metering Adjustments	Delivery Adjustments

12. Minimum Demand KW: None

13. Minimum Term: None

14. Transmission Service for Partial Requirements Customers:

Transmission Delivery Point(s)	KV (Nominal)	Subtransmission Delivery Point(s)	KV (Nominal)

SCHEDULE 21 - NEP

NEW ENGLAND POWER COMPANY
LOCAL SERVICE SCHEDULE

I. COMMON SERVICE PROVISIONS

1 Definitions

Whenever used in this Schedule, in either the singular or plural number, the following capitalized terms shall have the meanings specified in this Section 1. Terms used in this Schedule that are not defined in this Schedule shall have the meanings set forth in the Tariff or customarily attributed to such terms by the electric utility industry in New England.

1.0 New England Affiliate: New England Affiliate means Massachusetts Electric Company, Nantucket Electric Company, The Narragansett Electric Company and Granite State Electric Company.

1.1 Annual Peak Load: The highest Network Load of the Network Customer during a calendar year.

1.2 Contract Termination Charge (CTC): New England Power Company's stranded cost charge to certain wholesale requirements customers, as defined and described in the Stipulations and Agreements and as calculated pursuant to Appendix 1 of the Offer of Settlement filed with the Commission in Docket Nos. ER97-678-000 and ER97-680-000.

1.3 Contribution in Aid of Construction (CIAC): A contribution in aid of construction pursuant to Section 118(b) of the Internal Revenue Code of 1986.

1.4 Distribution System: Distribution System means the facilities owned or supported by NEP or its New England Affiliates that do not constitute PTF or Non-PTF and are used for Transmission Service under the Tariff for Transmission Customers other than end-use customers.

1.5 [Reserved]

1.6 IRS Notice 87-82: Internal Revenue Service Notice 87-82, Providing guidance with Respect to the Treatment of CIACs (received by regulated public utilities) After Enactment of New Section 118(b) of the Internal Revenue Code.

1.7 IRS Notice 90-60: Internal Revenue Service Notice 90-60, Contribution in Aid of Construction, issued September 10, 1990.

1.7.1 Load Interconnections: Any load facility desiring to interconnect with NEP's electrical system or modify an existing interconnection, as further set forth in the Local Service Agreement in Schedule 21-Attachment A. In addition, Attachment C, D, E, F and H of Schedule 21-NEP shall apply.

1.8 Load Power Factor: The ratio of the load measured in kW to the same load measured in kVA during a one-hour period.

1.9 Load Ratio Share: Ratio of a Transmission Customer's monthly PTF Network Load occurring coincident with NEP's Total Monthly Peak Load, to NEP's Total Monthly Peak Load, calculated on a monthly basis.

1.10 [Reserved]

1.11 Monthly Transmission Expenses: The total monthly cost of the Transmission System as specified in Attachment RR to this Schedule until amended by NEP or modified by the Commission.

1.12 NEP: NEP means New England Power Company, a Transmission Owner under the Tariff

1.13 NEPOOL Tariff: The predecessor NEPOOL Open Access Transmission Tariff as filed with the Commission on December 31, 1996 and as amended and in effect from time to time.

1.14 NERC: North American Electric Reliability Council

1.15 Network Load: The load interconnected (not reduced for any generation behind the meter) to the PTF, Non-PTF or Distribution Facilities of NEP or its New England Affiliates either directly or through Distribution Facilities or Non-PTF Facilities of other entities that a Network Customer designates to receive Local Network Service under Schedule 21 and this Schedule.

For purposes of establishing rates and charges under this Schedule, the Network Load will be subdivided into one of three categories:

A. **PTF Network Load** shall be the load over NEP's Local Network and shall equal the load of Network Customers directly interconnected with NEP's PTF or indirectly utilizing NEP's PTF through Non-PTF or Distribution Facilities of NEP or its New England Affiliates.

B. **Non-PTF Network Load** shall be the load over NEP's Non-PTF either directly interconnected with NEP's Non-PTF or indirectly utilizing NEP's Non-PTF through Distribution Facilities of NEP or its New England Affiliates.

C. **Distribution Facilities Network Load** shall be the load interconnected to the Distribution Facilities of NEP, its New England Affiliates or other entities.

1.16 **Network Upgrades:** Modifications or additions to transmission-related facilities that are integrated with and support NEP's overall Transmission System for the general benefit of all users of such Transmission System or to reliably integrate a generating unit with the Transmission System or to interconnect to outside control areas.

1.17 **Non-PTF Load Ratio Share:** Ratio of a Transmission Customer's monthly Non-PTF Network Load occurring coincident with NEP's Total Monthly Non-PTF Peak Load, to NEP's Total Monthly Non-PTF Peak Load.

1.18 **NPCC:** Northeast Power Coordinating Council, a regional reliability governing body.

1.19 **Own Use Energy:** Energy consumed by NEP's transmission facilities for purposes including but not limited to station service and sleet thawing, but excluding losses incurred on the Transmission System.

1.20 **Parties:** NEP and the Transmission Customer receiving service under this Schedule and the Tariff.

1.21 **Payment Schedule:** The payment schedule attached to a Local Service Agreement containing estimated milestones and estimated costs.

1.22 Policy and Practices for Protection Requirements for New or Modified Load Interconnections: NEP's policy concerning protection requirements for new or modified interconnections to loads, are included in the associated attachments of the Transmission Customer's Local Service Agreement.

1.23 Project: The substation and all facilities ancillary and appurtenant thereto, which the Transmission Customer requests to interconnect to the Transmission System, as more fully described in associated attachments to this Schedule 21-NEP and Attachment A to Schedule 21, Local Transmission Service.

1.24 Qualified Bidders List: A list of contractors and vendors qualified by NEP to work on interconnection facilities.

1.25 REMVEC: The Rhode Island, Eastern Massachusetts, Vermont Energy Control, which operates as a Local Control Center to the ISO.

1.26 Taxable Event: An event taxable to NEP resulting from transfers made by the Transmission Customer to NEP for services provided under this Schedule and Schedule 21 with respect to construction and installation of new Direct Assignment Facilities or improvements.

1.27 Total Monthly Peak Load: For each month, the highest hourly sum of the coincident peaks of deliveries to all PTF Network Loads under this Schedule, plus the loads of customers served under New England Power Company's (NEP) FERC Electric Tariff, Original Volume No. 1, connected directly to NEP's PTF or indirectly utilizing NEP's PTF through Non-PTF or Distribution Facilities of NEP, its New England Affiliates or other entities, including losses and NEP's Own Use Energy.

1.28 Total Monthly Non-PTF Peak Load: For each month, the highest hourly sum of the coincident peaks of deliveries to all Non-PTF Network Loads under this Schedule plus the loads of customers served under NEP's FERC Electric Tariff, Original Volume No. 1, that would otherwise qualify as Non-PTF Network Load, including losses and NEP's Own Use Energy.

1.29 Transformation Facilities: One or more transformers in a substation that step the voltage from the transmission voltage level to the distribution voltage level.

1.30 Transmission Service: Service provided under the OATT.

1.31 Transmission System: Transmission System means the facilities owned, controlled or operated by NEP that are used to provide Transmission Service.

2 Purpose of This Schedule

The OATT provides for a two-tier transmission arrangement integrating regional transmission service over PTF and Local Service over Non-PTF. The arrangement is designed and shall be operated in such a manner as to encourage and promote competition in the electric market to the benefit of ultimate users of electric energy. The OATT is intended to provide for comparable, non-discriminatory treatment of all similarly situated Transmission Owners and all Eligible Customers that are transmission users, and it shall be construed in the manner which best achieves this objective.

This Schedule functions in conjunction with the OATT to offer Transmission Services and Ancillary Services not provided pursuant to the other sections of the OATT, and to provide for the recognition of payments by and credits to NEP under the OATT. The rates, terms and conditions of this Schedule supplement and, where applicable, replace the rates, terms and conditions of the OATT and Schedule 21 with respect to Local Service; however Local PTP Service is not offered by NEP. In the event of a conflict between the terms of this Schedule and the terms of Schedule 21 with respect to Local Service, the terms of this Schedule shall govern.

Pursuant to this Schedule and to Schedules 22 and 23, NEP: (a) offers access to its Transmission Facilities for Excepted Transactions; (b) offers access to its Non-PTF in conjunction with the purchase of Transmission Service under the OATT; (c) provides rates, terms and conditions for the interconnection of new network load to the Transmission System and Distribution System for wholesale transactions; (d) reflects in the charges for Transmission Service and Ancillary Services amounts paid by NEP or credited to NEP in accordance with the OATT; and (e) provides for the recovery of costs associated with the Transmission Facilities and Ancillary Services that are not recovered pursuant to the OATT.

3 Ancillary Services

Ancillary Services are needed with Transmission Service to maintain reliability within and among the Control Areas affected by the Transmission Service. NEP is required to provide and the Network Customer or the Transmission Customer taking service in accordance with this Schedule and the OATT is required to purchase Local Scheduling, System Control and Dispatch Service in accordance with the rates and/or methodology described in Attachment S-1 and Attachment OCC to this Schedule.

4 Billing and Payment

4.1 Billing Procedure: Within a reasonable time after the first day of each month, NEP or its designee shall submit an invoice to the Transmission Customer for the charges for all services furnished by NEP under this Schedule and Schedule 21 during the preceding month. The invoice shall be paid by the Transmission Customer within twenty-five (25) days of issuance. All payments shall be made in immediately available funds payable to NEP, or by wire transfer to a bank named by NEP.

4.2 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to NEP on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after NEP notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, NEP may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between NEP and the Transmission Customer, NEP will continue to provide service under the Local Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then NEP may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

4.3 After Termination or Cancellation: The applicable provisions of the OATT, Schedule 21, this Schedule and any Local Service Agreement shall continue in effect after termination or cancellation thereof to the extent necessary to provide for final billings, billing adjustments and payments and with respect to liability and indemnification from acts or events that occurred while the Local Service Agreement was in effect. Notwithstanding the above, if the OATT, Schedule 21, this Schedule or any Local Service Agreement is terminated prior to the end of its initially contemplated term, for reasons other than breach by NEP, the Transmission Customer shall reimburse NEP for all unrecovered costs applicable to facilities installed pursuant to the provisions of the OATT, Schedule 21, this Schedule or any Local Service Agreement.

4.4 Audits of Accounts and Records: Within two (2) years following a calendar year, NEP and the Transmission Customer shall have the right to audit each other's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service for said calendar year. The party being audited will be entitled to review the audit report and any supporting materials. The independent auditor performing such audit shall be subject to a confidentiality agreement between the auditor and the party being audited. To the extent that audited information includes confidential information, the auditing party shall designate an independent auditor to perform such audit. For the purpose of this provision, confidential information is proprietary information supplied by a Transmission Customer or a provider of Ancillary Services to NEP, which the Transmission Customer or a provider of Ancillary Services requests NEP not to disclose. NEP will treat such information as confidential except to the extent that disclosure of this information is required by the OATT, by regulatory or judicial order for reliability purposes pursuant to Good Utility Practice, pursuant to the Commission's Final Order 889 in Docket No. RM95-9-000, or as required under the ISO New England Information Policy. NEP will not disclose such information to its power marketing Affiliate or others.

5 Creditworthiness

For the purpose of determining the ability of a Transmission Customer to meet its obligations related to service hereunder, NEP may require reasonable credit review procedures. Applicable creditworthiness procedures are specified in Attachment L of this Schedule.

6 Dispute Resolution Procedures

6.1 Interpretation: The interpretation of and performance under this Schedule shall be according to and controlled by the laws of the Commonwealth of Massachusetts when not in conflict with or pre-empted by the Federal Power Act.

6.2 Indemnification: In cases where the Transmission Customer enjoys limitation of its liability under the Massachusetts Tort Claims Act, G.L. c. 258, 1 and 2, as ame time to time, NEP will have a similar limitation on its liability under the OATT, Schedule 21 and this Schedule.

II. LOCAL NETWORK SERVICE

The rates, terms and conditions set forth below supplement and, where applicable, replace the rates, terms and conditions of Local Network Service set forth in Schedule 21. In the event of a conflict between the terms of this Schedule and the terms of Schedule 21, the terms of this Schedule shall govern.

19 Real Power Losses

Real Power Losses are associated with all Transmission Service. NEP is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all Transmission Service as calculated by NEP. The applicable Real Power Loss factors tabulated in Attachment I to this Schedule will be applied to metered loads to account for losses on the Non-PTF System and/or Distribution System that are not otherwise accounted for and allocated. Determination of losses across NEP's PTF system will be according to the procedure set by the ISO. In cases where the ISO or the Tariff does not allocate PTF losses, PTF losses will be assigned at 3%. When a load interconnects to the Transmission System at a Non-PTF point, the Real Power Loss factors in Attachment I to this Schedule will be applied to metered load amounts to reflect the losses incurred between the metering point and the PTF. Application of appropriate loss compensation to the meter would negate the need to apply the Real Power Loss factors. The Real Power Loss factors vary, depending upon the system voltage level at the interconnection point. If multiple voltage levels intervene between the PTF and the interconnection point/metering point, the Real Power Loss factors for each of the intervening voltage levels are additive. Any Non-PTF losses not allocated under Attachment I to this Schedule will be allocated to Non-PTF Network Load on the basis of Non-PTF Load Ratio Share.

20 Metering and Power Factor Correction at Point(s) of Delivery

20.1 Power Factor: The Network Customer's cumulative Load Power Factor for all Point(s) of Delivery in an area as defined by the ISO shall be maintained within a range, as required by

NEP, the ISO, and/or REMVEC, in accordance with Good Utility Practice. This range will be reviewed periodically and is subject to change. The Network Customer shall be notified of such changes. If the Network Customer's cumulative Load Power Factor does not fall within the required range, and NEP has existing means of providing the deficient reactive power NEP will charge the Network Customer a Power Factor Penalty in accordance with Attachment OCC to this Schedule. The Power Factor Penalty charge will be suspended if the customer corrects the Load Power Factor or, if during periods when the range may be changed, the customer's Load Power Factor is within the prescribed range. If NEP cannot provide the deficient reactive power from existing facilities, NEP will install, at the Customer's sole expense, the appropriate equipment to bring the customer's power factor within the required range. NEP will file with the Commission the cost support for such installations.

21 Network Resources

21.1 [Reserved]

21.2 Designation of New Network Resources: Each designation of a Network Resource shall be effective as of the beginning of a month, shall remain in effect for at least one full month, and shall only be terminated at the end of a month.

22 Construction of Facilities Associated with Interconnection of New Network Load

22.1 Basic Understandings: In cases in which the Transmission Customer intends to interconnect new network load to the Transmission System or Distribution System, the interconnection: (i) shall require the construction of interconnection facilities and associated equipment and (ii) may require the construction or installation of facilities and/or associated equipment in addition to the interconnection facilities on the Transmission System or Distribution System or the transmission system of another utility. These interconnection facilities and additional facilities shall be the financial responsibility of the Transmission Customer, to the extent consistent with Commission policy.

Subject to the following terms and conditions, NEP or its New England Affiliate shall, at the Transmission Customer's expense, build the facilities or make preparations so that this construction can be submitted for written bids to parties on the Qualified Bidders List. NEP shall have the right to supervise any construction undertaken by qualified outside contractors at the Transmission Customer's expense and to reject any construction work which fails to meet its requirements.

22.2 General Considerations: NEP or its New England Affiliate or another party selected pursuant to this Section shall construct the facilities at the Transmission Customer's expense. NEP or its New England Affiliate shall design, own, and maintain the facilities. NEP and the Transmission Customer shall mutually agree upon a schedule for construction and final interconnection. NEP shall use due diligence to fulfill its obligations under this Schedule in order to permit the interconnection of the Project in a timely manner. NEP reserves the exclusive right to make the final interconnection between the Project and NEP's Transmission System. NEP shall use, or specify that the Transmission Customer's selected contractor use, standard equipment customarily employed by NEP or its New England Affiliate for its own system in accordance with Good Utility Practice in making the final interconnection.

The Transmission Customer shall pay NEP for all reasonable costs and fees required to enable NEP to fulfill its obligations, including any tax liability, the costs and fees of all permits, licenses, franchises or regulatory or other approvals necessary for the construction and operation of the facilities. NEP shall consult with Transmission Customer on decisions involving substantial additional costs to be incurred by NEP in fulfillment of its obligations.

22.3 Tax Security Arrangements: The Transmission Customer shall acknowledge that under IRS Notice 87-82, transfers made by the Transmission Customer to NEP for services provided hereunder with respect to the construction and installation of new facilities or improvements may, under certain circumstances cause a Taxable Event to NEP. The Transmission Customer agrees to assure NEP recovery of all potential tax costs, both state and federal, including all interest and penalty claims, if a Taxable Event occurs.

The Transmission Customer shall expressly agree to indemnify and save NEP harmless from and against any and all federal and/or state income tax, interest or penalty claims, or liability related to any tax gross-up incurred as a result of the work performed for and the services rendered to the Transmission Customer.

22.4 Security: In addition to the security provided for in Section 5 of this Schedule, the Transmission Customer shall agree to provide NEP with security for the potential tax liability for a term and in a form acceptable to NEP. Such security shall cover an amount calculated in accordance with the terms of Section 22.5 of this Schedule. If the Transmission Customer fails to provide NEP with satisfactory security within thirty (30) days of notice by NEP, NEP may cease all work related to the Transmission Customer's request until such security is in place.

NEP reserves the right to require the Transmission Customer to increase the value of the security to reflect changed circumstances including, but not limited to, an increase in the taxable value of the Direct Assignment Facilities or changes in tax law which affect NEP's tax position vis-à-vis the construction and installation of new or modified facilities. The Transmission Customer shall provide NEP with the security as well as any periodic renewals that may be required by NEP. Such security shall have a minimum term of one (1) year and, in the case of a letter of credit, shall designate NEP as beneficiary with authority to draw drafts on the issuer for the secured amount in accordance with this Schedule. Such security shall also provide that NEP may draw the full amount of the security in the event it has not been renewed, extended or replaced on or before thirty (30) days prior to the expiration date of such security.

If at any time during the term of the Transmission Customer's Service Agreement with NEP there is a change in federal law tax which, in NEP's view, mitigates or eliminates its tax liability under applicable law or regulation, NEP shall agree, to the extent it deems appropriate, to release to the Transmission Customer any security determined to be in excess of NEP's potential tax liability.

22.5 Determination of Secured Amount: The Transmission Customer agrees that if a Taxable Event occurs, NEP's tax liability will be based upon the fair market value of the facilities constructed, installed or modified hereunder. The Transmission Customer agrees that the fair market value of the facilities is deemed to be the depreciated replacement cost of such facilities at the time of the transfer, as prescribed by IRS Notice 90-60.

The Transmission Customer shall secure an amount equal to the product of the depreciated replacement cost of the facilities times NEP's gross-up tax factor (net federal and state tax rate). NEP shall provide an initial estimate of the amount to be secured, based upon its facilities construction, installation or modification estimate. These projected figures, however, are subject to adjustment for actual construction costs when they become known.

The Transmission Customer shall agree to increase the secured amount to reflect any other adjustments as required by NEP to ensure that the existing security is sufficient to cover NEP's potential tax liability. The Transmission Customer shall agree to increase the secured amount within thirty (30) days of receipt of notice from NEP of any such adjustment to these costs. In the event that the Transmission Customer fails to do so, NEP shall have the right to seek termination of its service to the Transmission Customer until it increases the secured amount to the level specified by NEP.

22.6 Payment of Tax and Reconciliation: In the event that a Taxable Event occurs, NEP may exercise its rights under the security arrangement and draw upon all amounts necessary to pay the applicable taxes. If, in NEP's judgment, there are insufficient funds from such security to pay the applicable taxes, the Transmission Customer agrees to provide NEP with the balance of the funds needed within fifteen (15) days notice from NEP of such insufficiency. Any excess funds covered by security shall remain at NEP's disposal until NEP has received a final determination from the taxing authorities on the amounts payable as a result of the Taxable Event.

Upon such final determination, there shall be a reconciliation of the taxes payable by NEP, including any interest or penalties, and amounts provided by the Transmission Customer, in the form of security or otherwise. If the funds provided by the Transmission Customer prove insufficient to cover NEP's tax liability, the Transmission Customer shall pay NEP the amount of the underpayment within fifteen (15) days notice from NEP of the additional amount owed. If NEP receives a refund from the taxing authorities of any amounts paid due to the Taxable Event, NEP shall refund to the Transmission Customer such amount refunded to NEP. If taxes had not as yet been paid by NEP, in the form of estimated tax payments or otherwise, NEP shall refund the amount paid by the Transmission Customer in excess of NEP's actual tax liability. Interest on such amounts shall accrue, from the applicable following date: (a) the date the refund is received by NEP; (b) the date of recovery of estimated taxes previously paid by NEP (i.e., the due date of the tax payment following the determination); or (c) the date of final payment by the Transmission Customer under this Schedule, to the date NEP refunds such amount to the Transmission Customer. Once the Transmission Customer has fulfilled all of its obligations with respect to the final determination of the tax amounts payable, NEP shall release the Transmission Customer from all obligations under this Section. Interest, however, will not apply when a Letter of Credit is used as security.

22.7 IRS Private Letter Ruling. In the case of a Contribution in Aid of Construction ("CIAC") amounting to at least $100,000 and upon written request by a Transmission Customer, NEP will request a Private Letter Ruling from the Internal Revenue Service on the taxable nature of the Transmission Customer's CIAC. The Transmission Customer must submit such written request to NEP, with payment for the estimated costs of obtaining such ruling, within 30 days of the Commission's acceptance of the transmission Customer's Service Agreement (or its amendment) covering construction under this Schedule. Payment shall be sufficient to cover NEP's estimated expenses in retaining outside tax counsel with expertise in such matters, all regulatory, filing and application fees and any other reasonable expenses, including salary and overhead costs, deemed appropriate and necessary for preparing, managing and obtaining the ruling.

The Transmission Customer shall be responsible for all costs that NEP incurs in pursuing the Private Letter Ruling. If NEP's costs in pursuing the Private Letter Ruling exceed the estimated costs shown, it shall so notify the Transmission Customer and the Transmission Customer shall reimburse or pay the estimated additional cost, as the case may be, within thirty (30) days of notification. NEP shall not be responsible for pursuing or continuing to pursue the Private Letter Ruling if the Transmission Customer has not complied with these payment provisions.

The Transmission Customer agrees that the selection and retention of outside tax counsel in this regard shall be exclusively determined by NEP. Furthermore, the Transmission Customer understands that NEP cannot predict or guarantee the outcome of the Private Letter Ruling and, should the Internal Revenue Service deem the CIAC taxable to NEP, the Transmission Customer must meet its financial obligations to NEP to cover federal and state taxes.

The Transmission Customer shall cooperate in the preparation and provision of information, documents and other materials needed by NEP and its outside counsel for the Private Letter Ruling application and its supporting description and analysis. As soon as practicable after NEP's receipt of the Private Letter Ruling from the IRS, it shall provide the Transmission Customer with a copy of the document. The parties agree that the decision of the IRS as to the taxable status of the CIAC shall be binding upon the parties, their successors and/or assigns.

22.8 Land Interests: The Transmission Customer recognizes that acquisition of the land interests necessary for the interconnection facilities may require individual agreements between NEP or its New England Affiliate and the landowners. The Transmission Customer agrees to pay NEP all its reasonable costs associated with these acquisition agreements in advance of their execution. In the event the Transmission Customer acquires the land, permits, licenses, franchises or regulatory or other approvals necessary for the construction and operation of the interconnection facilities, NEP has the right, at the Transmission Customer's expense, to approve or reject any terms and conditions related thereto prior to the acceptance of the interconnection facilities.

22.9 Construction: If the Transmission Customer does not request that the construction of the interconnection facilities be submitted for written bids as described below, NEP or its New England Affiliate shall construct the interconnection facilities and the Transmission Customer shall pay NEP the total costs associated with the construction of the interconnection facilities. The estimated costs (exclusive of any regulatory approval costs and/or fees) and the schedule for the Transmission Customer's payments to NEP will be shown the Service Agreement.

The Transmission Customer shall pay NEP following the close of the Transmission Customer's construction financing (if any) in accordance with the Payment Schedule shown in the Service Agreement. The Payment Schedule contains estimated milestones and estimated costs. NEP shall invoice the Transmission Customer for costs, on an estimated basis.

Within a reasonable period of time following completion of the interconnection facilities, NEP shall provide the Transmission Customer with a report of actual construction costs sufficient to allow identification of all major cost components. Upon completion of the interconnection facilities, the Transmission Customer and NEP agree to make a final adjustment to correct for any overpayment or underpayment of the construction costs.

22.10 Construction by Third-Party: The Transmission Customer may request that the construction of the interconnection facilities be submitted for written bids by NEP-approved contractors having the capability and skill to perform the work in accordance with the terms and conditions contained herein. The Transmission Customer shall assume all risks and consequences associated with the decision to use such bidding process.

The Transmission Customer understands that if a contractor other than NEP or its New England Affiliate constructs the interconnection facilities, the RFP process and interconnection facilities construction may require more time than if NEP or its New England Affiliate constructed the interconnection facilities. Notwithstanding the foregoing, the Transmission Customer understands and agrees that all construction work on existing facilities shall be done by NEP or its New England Affiliate. Such work shall not be included in the work submitted for bid by the Transmission Customer to outside contractors.

If the Transmission Customer requests that the construction of the interconnection facilities be submitted for written bids in accordance with the preceding paragraph, NEP shall prepare RFPs for construction of the interconnection facilities which, at a minimum, shall include construction drawings, steel structure specifications, bid drawings and specifications, materials specifications, and construction specifications. NEP shall also prepare the Qualified Bidders List. Materials, including steel structures, shall be obtained from suppliers listed in the Qualified Bidders List. The Transmission Customer shall seek NEP's prior approval with respect to any additions to the Qualified Bidders List or substitution of equal items of material from approved suppliers. The Transmission Customer shall reimburse NEP for its reasonable costs of preparing the RFPs and the Qualified Bidders List.

Upon the Transmission Customer's acceptance of the RFPs and the Qualified Bidders List, the Transmission Customer shall issue the RFPs to the contractors on the Qualified Bidders List. NEP and its New England Affiliates shall have the right to respond to the RFPs. The Transmission Customer shall review the responses to the RFPs and select a contractor to construct the interconnection facilities. Selection of the contractor shall be at the Transmission Customer's sole discretion, but subject to the limitations and criteria contained herein. The contractor selected by this process shall contract directly with the Transmission Customer for this construction. In no event shall NEP become legally or financially obligated to the selected contractor for construction of the interconnection facilities or any other related work.

If NEP or its New England Affiliate is not the successful bidder, NEP shall have the ongoing right to monitor, at the Transmission Customer's expense, and approve or reject the contractor's construction of the interconnection facilities to ensure that the contractor's performance satisfies NEP's specifications and the criteria set forth in this Schedule and all appendices, exhibits, and attachments hereto. NEP shall have the right to make a final inspection and acceptance of the completed interconnection facilities. NEP's evaluation and acceptance of the interconnection facilities shall be based on compliance with the contract specifications; Good Utility Practice; the National Electric Safety Code as in effect during the time of construction; the appropriate state rules and regulations; NEP's Policy and Practices for Protection Requirements for New or Modified Load Interconnections; and other practices, procedures, specifications, and applicable standards developed by NEP's New England Affiliate. Any part of the work which NEP reasonably finds unsatisfactory shall be corrected prior to its acceptance of the completed interconnection facilities.

If the Transmission Customer selects a contractor other than NEP or its New England Affiliate, within thirty days following completion of the interconnection facilities, the Transmission Customer shall provide NEP with all detailed construction cost data that NEP needs to meet construction cost unitizing requirements under the Federal Power Act and relevant regulations.

22.11 Delivery and Measurement of Electricity:

22.11.1 Voltage Level: All electricity across the interconnection point shall be the form of three-phase sixty-hertz alternating current at a voltage class determined by mutual agreement of the parties.

22.11.2 Machine Reactive Capability: The Transmission Customer will be required to provide reactive capability to regulate and maintain system voltage at the interconnection point. NEP and the ISO shall establish a scheduled range of voltages to be maintained by the Project. The reactive capability requirements shall be reviewed during the System Impact Study and Facilities Study.

22.11.3 Metering and Related Equipment: The Transmission Customer shall be responsible for the cost of installing and maintaining compatible metering and communication equipment at or distant from the Project which measures steam flow, if the Project is a generating source (as applicable and where necessary), as well as electricity flows between NEP and Transmission Customer and determines the status of switching equipment. The Transmission Customer shall be responsible for communicating to NEP accurate information on capacity and energy being transmitted. Instrument transformers shall be approved by NEP before the design is finalized. In cases where it may be appropriate for the metering equipment to be installed at the Transmission

Customer’s property, NEP reserves the right to inspect, commission and witness test such meters. NEP shall also have access to read such meters remotely and locally to facilitate measurements and billing.

The Transmission Customer shall provide suitable space within its facilities for installation of the metering, telemetering, environmental control, and communication equipment at no cost to NEP.

The Transmission Customer shall be responsible for providing all necessary leased telephone lines and any necessary protection for leased lines and shall furthermore be responsible for all communication required by the ISO, or its designee. The Transmission Customer shall maintain all telemetering and transducer equipment on the Project in accordance with applicable criteria, rules, standards and operating procedures. At the Transmission Customer's expense, NEP shall purchase, own and maintain all telemetering equipment located on NEP’s facilities. The Transmission Customer shall be responsible for the cost of installing NEP-approved or NEP-specified test switches in the transducer circuits.

If the metering equipment, the interconnection point and the Point(s) of Receipt are not at the same location, the metering equipment shall record delivery of electricity in a manner that accounts for losses occurring between the metering point and the Point(s) of Receipt or between the metering point and the interconnection point, as appropriate. Accounting for transmission losses between the metering point and the Point(s) of Receipt or between the metering point and the interconnection point shall be pursuant to the rates, terms and conditions of this Schedule and the OATT.

All metering equipment may be routinely tested by NEP at the Transmission Customer's expense, in accordance with applicable criteria, rules, standards and operating procedures. If, at any time, any metering equipment is found to be inaccurate by a margin greater than that allowed under applicable criteria, rules, standards and operating procedures, NEP shall cause such metering equipment to be made accurate or replaced at the Transmission Customer's expense. Meter readings for one-half the period extending back to the last successful meter test shall be adjusted so far as the same can be reasonably ascertained. Each party shall comply with any reasonable request of the other concerning the sealing of meters, the presence of a representative of the other party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of electricity delivered from the Project. If either party believes that there has been a meter failure or stoppage, it shall immediately notify the other.

The Transmission Customer shall be responsible for the cost of purchasing and installing software, hardware and/or other technology that may be required to read billing meters.

The Transmission Customer shall be responsible for the costs of all metering and related equipment pursuant to Attachment OCC to this Schedule and/or Attachment DAF to this Schedule, as applicable.

22.12 Notice Provisions: If at any time, in the reasonable exercise of NEP's judgment, operation of the Project adversely affects the quality of service to other customers or interferes with the safe and reliable operation of the Transmission System or Distribution System, NEP may discontinue service to the Transmission Customer until the condition has been corrected. Unless an emergency exists or the risk of one is imminent, NEP shall give the Transmission Customer reasonable notice of its intention to discontinue service and, where practical, allow suitable time for the Transmission Customer to remove the interfering condition. NEP's judgment with regard to discontinuance of deliveries or disconnection of facilities under this paragraph shall be made in accordance with Good Utility Practice. In the case of such discontinuance, NEP shall immediately confer with the Transmission Customer regarding the conditions causing such discontinuance and its recommendation concerning the timely correction thereof.

22.13 Access and Control: Properly accredited representatives of NEP or its New England Affiliates shall at all reasonable times have access to the Project to make reasonable inspections and obtain information required in connection with this Schedule. At the Project, such representatives shall make themselves known to the Transmission Customer's personnel, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Project. NEP or its New England Affiliates will have control such that it may open or close the circuit breaker or disconnect and place safety grounds at the Point(s) of Receipt, or at the station, if the Point(s) of Receipt is (are) remote from the station.

22.14 Insurance Requirements: The Transmission Customer shall be subject to the insurance requirements specified in the Local Service Agreement.

23 Load Shedding and Curtailments

23.1 Transmission Constraints: During any period when NEP determines that a transmission constraint exists on the Non-PTF, and such constraint may impair the reliability of the New England Transmission System, NEP will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent NEP determines that the reliability of the New England Transmission System can be maintained by redispatching resources, NEP will initiate procedures pursuant to contracts with owners of the identified resources to redispatch all Network Resources and NEP's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this Section may not unduly discriminate between NEP's use of the Non-PTF on behalf of its Native Load Customers and any Network Customer's use of the Non-PTF to serve its designated Network Load.

23.2 Cost Responsibility for Relieving Transmission Constraints: Whenever NEP implements least-cost redispatch procedures in response to a transmission constraint, NEP and the Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

23.3 System Reliability: A Network Customer that fails to respond to established load shedding and curtailment procedures will be deemed by NEP of making unauthorized use of the Transmission System. If unauthorized use occurs, NEP will charge and the Transmission Customer will be obligated to pay a penalty equal to twice the standard rate for such a transaction, as described more fully in Section 24.15 of this Schedule. In all cases of unauthorized use of the Transmission System, the service will be considered non-firm and NEP will be under no obligation to provide any services for such use.

24 Compensation for Local Network Service

The following rates and charges may apply to Local Network Service as specified below. Charges under this Section shall include any applicable PTF costs not otherwise recovered under the OATT. To the extent that NEP enters into an incentive rate plan(s), the incentive rate terms shall be reflected in a separate filing with the Commission under Section 205 of the Federal Power Act. Additionally, all costs and revenues under such incentive rate plan(s) shall be excluded from NEP's PTF and Non-PTF Transmission Revenue Requirement. However, liquidated damages mandated by the Commission in

Docket No. RM02-1-000 shall be reflected in NEP's costs and included in its PTF and Non-PTF Transmission Revenue Requirement calculations.

24.1 Monthly Demand Charge: Any Network Customer utilizing NEP's PTF facilities either directly or indirectly shall pay a Monthly Demand Charge as calculated in accordance with Attachment OCC to this Schedule.

24.2 Monthly Non-PTF Demand Charge: Any Network Customer with Network Load qualifying as Non-PTF Network Load, shall pay a Monthly Non-PTF Demand Charge determined in accordance with Attachment OCC to this Schedule.

24.3 Transformer Surcharge: In the event that a Network Customer does not own the stepdown transformation from 69 kV or greater voltage to distribution voltage level, where it utilizes NEP's Transformation Facilities, the Network Customer will be subject to a Transformer Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.4 Meter Surcharge: If the Network Customer neither owns nor supports metering equipment necessary for provision of Local Network Service, that customer will be subject to a Meter Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.5 Power Factor Penalty: Pursuant to the requirements of Section 20.1 of this Schedule, the Network Customer may be subject to a Power Factor Penalty calculated in accordance with Attachment OCC to this Schedule.

24.6 Direct Assignment Facility Charge: The Direct Assignment Facility Charge compensates NEP for the annual costs of the facilities, expansions and upgrades that may be directly assigned by NEP or by the ISO, as appropriate, to the Transmission Customer. These costs may include, but are not limited to, the capital carrying cost, income tax, depreciation, operation and maintenance, administrative and general expenses and property tax. The Direct Assignment Facility Charge shall be calculated as specified in Attachment DAF to this Schedule. In no event shall the Direct Assignment Facilities Charge be less than $1,000.00 per year. If NEP enters into an agreement for use and support of facilities owned by other entities on behalf of a Transmission Customer, any charges incurred by NEP will be directly assigned to the Transmission Customer.

The Direct Assignment Facilities Charge in each year shall be billed based on forecast data for that year and shall be adjusted for experienced costs as soon as practicable after the close of the year. The charge so calculated shall commence on the date the facilities, expansions or upgrades are placed in service.

24.7 Distribution Service:

24.7.1 Specific Distribution Surcharge: Any Network Customer listed in Attachment OCC, VI, to this Schedule, which relies on the specific distribution facilities of NEP's New England Affiliate, Massachusetts Electric Company, as provided to NEP under the Integrated Facilities provision of NEP's FERC Electric Tariff No. 1 (Tariff No. 1), will be subject to a Specific Distribution Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.7.2 Rolled-In Distribution Surcharge: To the extent that a Network Customer listed in Attachment OCC, VI, to this Schedule, utilizes distribution facilities in addition to the specific facilities identified in NEP's Tariff No. 1 (as of February 28, 1998), the Network Customer will pay the Rolled-In Distribution Surcharge calculated in accordance with Attachment DS to this Schedule for delivery service to load. To the extent that distribution service to a new Network Customer is subject to the direct jurisdiction of the Federal Energy Regulatory Commission, the provision of distribution service to that customer on or after March 1, 1998 shall be reflected in the Network Customer's Local Service Agreement.

In the event that the integrated distribution facilities under NEP's FERC Electric Tariff No. 1 are otherwise eliminated or superseded, the customers listed in Attachment OCC, VI, to this Schedule, will take distribution service entirely under the Rolled-In Distribution Surcharge calculated in accordance with Attachment DS to this Schedule.

24.8 Ancillary Services: Any Network Customer with Network Load qualifying as PTF Network Load will be subject to the Network Load Dispatch Surcharge calculated in accordance with Attachment OCC to this Schedule.

24.9 OASIS Charges: Identifiable usage-dependent costs of OASIS may be charged to the specific user in accordance with the Commission's Final Order 889 in Docket No. RM95-9-000, and any subsequent amendments thereto.

24.10 [Reserved]

24.11 EPRI Credit: The Network EPRI Credit, calculated in accordance with Attachment OCC to this Schedule, shall apply to any wholesale Network Customer, which is not also an Affiliate of NEP.

24.12 Pre-1997 RNS Revenue Credit: Pursuant to the compliance filing made by NEP in FERC Docket Nos. EC99-70-00 and ER99-2832-000 (Not Consolidated), Taunton Municipal Lighting Plant, Middleborough Gas and Electric Department and Pascoag Fire District will receive a credit in their monthly bill under this Schedule calculated in accordance with Attachment OCC to this Schedule.

24.13 Network Upgrade Charge: If network upgrades are required in association with a new load, the Network Customer shall be required to pay a Network Upgrade Charge. The monthly Network Upgrade charge shall be the higher of (i) the allocated Monthly Transmission Expenses for Local Network Service with the New Network Upgrades rolled-in; or (ii) an incremental monthly charge for service based upon the total costs of the Network Upgrades for which the Transmission Customer is responsible as determined by the formula in Attachment DAF to this Schedule.

24.14 Redispatch Charge: Pursuant to Section 23.2 of this Schedule, the Transmission Customer may be subject to charges for generation redispatch.

24.15 Unauthorized Use Penalty: Pursuant to Section 23.3 of this Schedule, the Transmission Customer may be subject to a penalty equal to twice the standard rate for unauthorized use of the Transmission System, based on the period of unauthorized use.

The annual standard rate per KW for unauthorized use of the Transmission System shall be derived from (i) the previous calendar year's annual transmission expenses as calculated in

Attachment RR, excluding any revenue credits associated with Section 24.1 of this Schedule divided by (ii) the average of the twelve Total Monthly Peak Loads from the previous year.[1]

The monthly standard rate per KW shall equal one-twelfth of the annual standard rate; the weekly standard rate per KW shall equal one-fifty-second of the annual standard rate; and the daily standard rate per KW shall equal one-fifth of the weekly standard rate.

The unauthorized use penalty charge for a single hour of unauthorized use shall be based on the daily standard rate, and more than one assessment for a given duration (e.g., daily) results in an increase of the penalty period to the next longest duration (e.g., weekly). The unauthorized use penalty charge for multiple instances of unauthorized use (i.e., more than one hour) within a day will be based on the daily standard rate. The unauthorized use penalty charge for multiple instances of unauthorized use isolated to one calendar week would result in a penalty based on the weekly standard rate. The unauthorized use penalty charge for multiple instances of unauthorized use during more than one week during a calendar month will be based on the monthly standard rate.

[1] The standard rate is analogous to the former Firm Local Point-To-Point Service rate that was eliminated from Schedule 21-NEP (Attachment J) effective November 1, 2007; *see Docket No. ER07-1323-000*.

ATTACHMENT C

Form of System Impact Study Agreement

This Agreement dated __________, is entered into by ____________ (the Transmission Customer) and New England Power Company (NEP), for the purpose of setting forth the terms, conditions and costs for conducting a System Impact Study relative to _________________________________.

1. The Transmission Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for NEP to conduct the System Impact Study. The Transmission Customer understands that it must provide all such information and data prior to NEP's commencement of the Study. Such information and technical data is specified in Exhibit 1 to this Agreement.

2. All work pertaining to the System Impact Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of NEP and the Transmission Customer. Each party shall inform the other in writing of its designated and authorized representative.

3. NEP will advise the Transmission Customer of any additional studies as it may in its sole discretion deem necessary. Any such additional studies shall be conducted only if required by Good Utility Practice and shall be subject to the Transmission Customer's consent to proceed, such consent not be unreasonably withheld.

4. NEP contemplates that it will require _______ to complete the System Impact Study. Upon completion of the Study by NEP, NEP will provide a report to the Transmission Customer based on the information provided and developed as a result of this effort. If, upon review of the Study results, the Transmission Customer decides to pursue ___________, NEP will, at the Transmission Customer's direction, tender a Facilities Study Agreement within thirty (30) days. The System Impact and Facilities Studies, together with any additional studies contemplated in Paragraph 3, shall form the basis for the Transmission Customer's proposed use of NEP's transmission system and shall be furthermore utilized in obtaining necessary third-party approvals of any interconnection facilities and requested transmission services. The Transmission Customer understands and acknowledges that any use of study results by the Transmission Customer or their agents, whether in preliminary or final form, prior to application approval pursuant to Section I.3.9 of the Tariff, is completely at the Transmission Customer's risk and that NEP

will not guarantee or warrant the completeness, validity or utility of study results prior to application approval pursuant to Section I.3.9 of the Tariff.

5. The estimated costs contained within this Agreement are NEP's good faith estimate of its costs to perform the System Impact Study contemplated by this Agreement. NEP's estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Transmission Customer by NEP may change as set forth in this Agreement. Prepayment will be required for all study, analysis, and review work performed by NEP or its Designated Agent, all of which will be billed by NEP to the Transmission Customer in accordance with Paragraph 6 of this Agreement.

6. The payment required is $______ from the Transmission Customer to NEP for the primary system analysis, coordination, and monitoring of the System Impact Study. NEP will, in writing, advise the Transmission Customer in advance of any cost increases for work to be performed if total amount increases by 10% or more. Any such changes to NEP's costs for the study work shall be subject to the Transmission Customer's consent, such consent not to be unreasonably withheld. The Transmission Customer shall, within thirty (30) days of NEP's notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or NEP will suspend the System Impact Study and this Agreement will terminate if so permitted by the Federal Energy Regulatory Commission.

In the event this Agreement is terminated for any reason, NEP shall refund to the Transmission Customer the portion of the above credit or any subsequent payment to NEP by the Transmission Customer that NEP did not expend in performing its obligations under this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Payments for work performed shall not be subject to refunding except in accordance with Paragraph 7 below.

7. If the actual costs for the work exceed prepaid estimated costs, the Transmission Customer shall make payment to NEP for such actual costs within thirty (30) days of the date of NEP's invoice for such costs. If the actual costs for the work are less than those prepaid, NEP will credit such difference toward NEP costs unbilled, or in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Transmission Customer with interest computed as stated in Paragraph 6 of this Agreement, from the date of reconciliation.

8. Nothing in this Agreement shall be interpreted to give the Transmission Customer immediate rights to wheel over or interconnect with NEP's Transmission or Distribution System. Such rights shall be provided for under separate agreement and in accordance with the OATT.

9. Within one (1) year following NEP's issuance of a final bill under this Agreement, the Transmission Customer shall have the right to audit NEP's accounts and records at the offices where such accounts and records are maintained, during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. NEP reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Transmission Customer or their Designated Agent.

10. Each party agrees to indemnify and hold the other party and its Affiliates, including affiliated trustees, directors, officers, employees, and agents of each of them, harmless from and against any and all damages, costs (including attorney's fees), fines, penalties and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen as a result of any acts or omissions of either party under this Agreement. Each party hereby waives recourse against the other party and its Affiliates for, and releases the other party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to a performance under this Agreement by such other party.

11. If either party materially breaches any of its covenants hereunder, the other party may terminate this Agreement by filing a notice of intent to terminate with the Federal Energy Regulatory Commission and serving notice of same on the other party to this Agreement.

12. This agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts and with Part II of the Federal Power Act, 16 U.S.C. §§824d et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§35 et seq.

13. All amendments to this Agreement shall be in written form executed by both parties.

14. The terms and conditions of this Agreement shall be binding on the successors and assigns of either party.

15. This Agreement will remain in effect for a period of up to two years from its effective date as permitted by the Federal Regulatory Commission, and is subject to extension by mutual agreement. Either party may terminate this Agreement by thirty (30) days' notice except as is otherwise provided herein. If this Agreement expires by its own terms, it shall be NEP's responsibility to make such filing.

NEP:

By:________________________ ________________ _______________
Name Title Date

Transmission Customer:

By:________________________ ________________ _______________
Name Title Date

System Impact Study Agreement

EXHIBIT 1

Information to be Provided to NEP
by the Transmission Customer for System Impact Study

1.0 Facilities Identification

1.1 Requested capability in MW and MVA; summer and winter

1.2 Site location and plot plan with clear geographical references

1.3 Preliminary one-line diagram showing major equipment and extent of Transmission Customer ownership

1.4 Auxiliary power system requirements

1.5 Back-up facilities such as standby generation or alternate supply sources

2.0 Major Equipment

2.1 Power transformer(s): rated voltage, MVA and BIL of each winding, LTC and or NLTC taps and range, Z1 (positive sequence) and Z0 (zero sequence) impedances, and winding connections. Provide normal, long-time emergency and short-time emergency thermal ratings.

2.2 Generator(s): rated MVA, speed and maximum and minimum MW output, reactive capability curves, open circuit saturation curve, power factor (V) curve, response (ramp) rates, H (inertia), D (speed damping), short circuit ratio, X1 (leakage), X2 (negative sequence), and X0 (zero sequence) reactances and other data:

	Direct Axis	Quadrature Axis
saturated synchronous reactance	Xdv	Xqv

	Direct Axis	Quadrature Axis
unsaturated synchronous reactance	Xdi	Xqi
saturated transient reactance	X'dv	X'qv
unsaturated transient reactance	X'di	X'qi
saturated subtransient reactance	X"dv	X"qv
unsaturated subtransient reactance	X"di	X"qi
transient open-circuit time constant	T'do	T'qo
transient short-circuit time constant	T'd	T'q
subtransient open-circuit time constant	T"do	T"qo
subtransient short-circuit time constant	T"d	T"q

2.3 Excitation system, power system stabilizer and governor: manufacturer's data in sufficient detail to allow modeling in transient stability simulations.

2.4 Prime mover: manufacturer's data in sufficient detail to allow modeling in transient stability simulations, if determined necessary.

2.5 Busses: rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), conductor type and configuration.

2.6 Transmission lines: overhead line or underground cable rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), Z1 (positive sequence) and Z0 (zero sequence) impedances, conductor type, configuration, length and termination points.

2.7 Motors greater than 150 kW 3-phase or 50 kW single-phase: type (induction or synchronous), rated hp, speed, voltage and current, efficiency and power factor at ½, 3/4 and full load, stator resistance and reactance, rotor resistance and reactance, magnetizing reactance.

2.8 Circuit breakers and switches: rated voltage, interrupting time and continuous, interrupting and momentary currents. Provide normal, long-time emergency and short-time emergency thermal ratings.

2.9 Protective relays and systems: ANSI function number, quantity manufacturer’s catalog number, range, descriptive bulletin, tripping diagram and three-line diagram showing AC connections to all relaying and metering.

2.10 CT’s and VT’s: location, quantity, rated voltage, current and ratio.

2.11 Surge protective devices: location, quantity, rated voltage and energy capability.

3.0 Other

3.1 Additional data to perform the System Impact Study will be provided by the Transmission Customer as requested by NEP.

3.2 NEP reserves the right to require specific equipment settings or characteristics necessary to meet the applicable criteria and standards.

ATTACHMENT D

Form of Facilities Study Agreement

This agreement dated __________, is entered into by ____________ (the Transmission Customer) and New England Power Company (NEP), for the purpose of setting forth the terms, conditions and costs for conducting a Facilities Study Agreement relative to ______________________________________. The Facilities Study will determine the detailed engineering, design and cost of the facilities necessary to satisfy the Transmission Customer's request for service over NEP's Transmission System.

1. The Transmission Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for NEP to conduct the Facilities Study. Where such information and technical data was provided for the System Impact Study, it should be reviewed and updated with current information, as required.

2. All work pertaining to the Facilities Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of NEP and the Transmission Customer. Each party shall inform the other in writing of its designated and authorized representative.

3. NEP will advise the Transmission Customer of additional studies as may be deemed necessary by NEP. Any such additional studies shall be conducted only if required by Good Utility Practice and shall be subject to the Transmission Customer's consent to proceed, such consent not to be unreasonably withheld.

4. NEP contemplates that it will require ___ days to complete the Facilities Study. Upon completion of the study by NEP, NEP will provide a report to the Transmission Customer based on the information provided and developed as a result of this effort. If, upon review of the study results, the Transmission Customer decides to pursue its transmission service request, the Transmission Customer must sign a supplemental Service Agreement with NEP. The System Impact and Facilities Studies, together with any additional studies contemplated in Paragraph 3, shall form the basis for the Transmission Customer's proposed use of NEP's Transmission System and shall be furthermore utilized in obtaining necessary third-party approvals of any facilities and requested transmission services. The Transmission Customer understands and acknowledges that any use of the study results by the Transmission Customer or their agents, whether in preliminary or final form, prior to application approval

pursuant to Section I.3.9 of the Tariff, is completely at the Transmission Customer's risk and that NEP will not guarantee or warrant the completeness, validity or utility of the study results prior to application approval pursuant to Section I.3.9 of the Tariff.

5. The estimated costs contained within this Agreement are NEP's good faith estimate of its costs to perform the Facilities Study contemplated by this Agreement. NEP's estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Transmission Customer by NEP may change as set forth in this Agreement. Prepayment will be required for all study, analysis, and review work performed by NEP's or its Designated Agent's personnel, all of which will be billed by NEP to the Transmission Customer in accordance with Paragraph 6 of this Agreement.

6. The payment required is $____ from the Transmission Customer to NEP for the primary system analysis, coordination, and monitoring of the Facilities Study to be performed by NEP for the Transmission Customer's requested service. NEP will, in writing, advise the Transmission Customer in advance of any cost increases for work to be performed if the total amount increases by 10% or more. Any such changes to NEP's costs for the study work to be performed shall be subject to the Transmission Customer's consent, such consent not to be unreasonably withheld. The Transmission Customer shall, within thirty (30) days of NEP's notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or NEP will suspend the study and this Agreement will terminate if so permitted by the Federal Energy Regulatory Commission. In the event this Agreement is terminated for any reason, NEP shall refund to the Transmission Customer the portion of the above credit or any subsequent payment to NEP by the Transmission Customer that NEP did not expend in performing its obligations under this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Payments for work performed shall not be subject to refunding except in accordance with Paragraph 7 below.

7. If the actual costs for the work exceed prepaid estimated costs, the Transmission Customer shall make payment to NEP for such actual costs within thirty (30) days of the date of NEP's invoice for such costs. If the actual costs for the work are less than that prepaid, NEP will credit such difference toward NEP costs unbilled, or in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Transmission Customer with interest computed in accordance with the provisions of the OATT.

8. Nothing in this Agreement shall be interpreted to give the Transmission Customer immediate rights to interconnect to or wheel over NEP's Transmission or Distribution System. Such rights shall be provided for under separate agreement.

9. Within one (1) year following NEP's issuance of a final bill under this Agreement, the Transmission Customer shall have the right to audit NEP's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. NEP reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Transmission Customer or their Designated Agent.

10. Each party agrees to indemnify and hold the other party and its Affiliates, including affiliated trustees, directors, officers, employees, and agents of each of them, harmless from and against any and all damages, costs (including attorney's fees), fines, penalties and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen as a result of any acts or omissions of either party under this Agreement. Each party hereby waives recourse against the other party and its Affiliates for, and releases the other party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to performance under this Agreement by such other party.

11. If any party materially breaches any of its covenants hereunder, the other party may terminate this Agreement by filing a notice of intent to terminate with the Federal Energy Regulatory Commission and serving notice of same on the other party to this Agreement.

12. This agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts and with Part II of the Federal Power Act, 16 U.S.C. §§824d et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§35 et seq.

13. All amendments to this Agreement shall be in written form executed by both parties.

14. The terms and conditions of this Agreement shall be binding on the successors and assigns of either party.

15. This Agreement will remain in effect for a period of up to two years from its effective date as permitted by the Federal Energy Regulatory Commission, and is subject to extension by mutual agreement.

Either party may terminate this Agreement by thirty (30) days' notice except as is otherwise provided herein. If this Agreement expires by its own terms, it shall be NEP's responsibility to make such filing.

NEP:

By:________________________ ________________ _______________

Name Title Date

Transmission Customer:

By:________________________ ________________ _______________

Name Title Date

ATTACHMENT E

Local Service Agreement

Policy and Practices for Protection Requirements
For New or Modified Load Interconnections

Any load facility, hereafter called a LF, desiring to interconnect with NEP's electrical system or modify an existing interconnection must meet the technical specifications and requirements set forth in this Policy and Practices. Once interconnected, NEP, in keeping with Good Utility Practice and in its sole discretion, may disconnect the LF if the LF departs from the technical specifications and requirements of this Policy and Practices. The LF must return to full compliance with this Policy prior to reconnecting with NEP's electrical system.

If it is possible for the LF to be a significant source of current flow into NEP's lines due to generation sources within the LF system then NEP may determine the LF to be considered a Generation Facility and the Policy and Practices for Protection Requirements for Generation Interconnections shall apply as set forth in the New England ISO OATT.

This document is divided into the following sections:

1. Protection Information Required from the LF for All Interconnections
2. General Protection Requirements for All LF Interconnections
3. Protection Equipment Requirements for All LF Interconnections
4. Requirements for Protection of NEP's System
5. Requirements for Protection of NEP's System: Facilities Having Sources
6. Requirements for Emergency Load Reduction
7. Protection System Testing and Maintenance
8. Changes to the LF's Protection System

1.) PROTECTION INFORMATION REQUIRED FROM THE LF FOR ALL INTERCONNECTIONS

A. The following information must be submitted by the LF for review and acceptance by NEP prior to finalizing the LF's protection design:

- A station one-line drawing.
- A one-line drawing showing the relays and metering including current transformer (CT) and voltage transformer (VT) connections and ratios.
- A three-line drawing showing the AC connections to the relays and meters.
- The LF’s transformer nameplate information including rated voltage, rated KVA, positive and zero sequence impedances and winding connections.
- A list of protective relay equipment proposed to be furnished to conform with this Policy and Practices including: relay types, styles, manufacturer's catalog numbers, ranges and descriptive bulletins.
- Schematic drawings showing the control circuits for the interconnection breaker(s) or equivalent interrupting device(s).
- Equipment specifications for CTs and VTs relevant to the interconnection.
- Interconnection breaker or equivalent interrupting device operating time.
- Other information that may be determined by NEP as required for a specific interconnection.

B. Relay settings for all LF protective relays that affect the interconnection with NEP’s system must be submitted by the LF for review and acceptance by NEP at least four weeks prior to the scheduled date for setting the relays.

C. If, due to the interconnection of the LF to the line, the fault interrupting, continuous, momentary or other rating of any of NEP's equipment or the equipment of others connected to NEP's system is exceeded, NEP shall have the right to require the LF to pay for the purchase, installation, replacement or modification of equipment to eliminate the condition. Where such action is deemed necessary by NEP, NEP will, where possible, permit the LF to choose among two or more options for meeting NEP’s requirements as described in this Policy and Practices.

2.) GENERAL PROTECTION REQUIREMENTS FOR ALL LF INTERCONNECTIONS

A. A circuit breaker, or other fault interrupting method acceptable to NEP, shall be installed to isolate the LF from NEP's system. This will hereafter be called the "interconnection breaker". If there is more than one interconnection breaker, the requirements of this Policy and Practices apply to each one individually.

B. NEP will review the relay settings as submitted by the LF to assure adequate protection for NEP's facilities. NEP shall not be responsible for the protection of the LF's facilities. Providing the relaying is installed and maintained as reviewed, the LF shall not be responsible for the protection of NEP's facilities. The LF shall be responsible for protection of its system against possible damage resulting from interconnection with NEP.

If requested by the LF, NEP will provide system protection information for the line terminal(s) directly related to the interconnection. This protection information is provided exclusively for use by the LF in evaluating protection of the LF's facilities during parallel operation.

C. NEP shall specify whether the transformer, if any, between NEP's voltage and the LF's distribution voltage, hereafter called the "LF's transformer", is to be grounded or ungrounded at NEP's voltage.

3.) PROTECTION EQUIPMENT REQUIREMENTS FOR ALL LF INTERCONNECTIONS

A. The interconnection breaker control circuits shall be DC powered from a station battery.

B. The LF shall provide a switch at the Interconnection Point with NEP that can be opened for isolation. NEP shall have the right to open the interconnection during emergency conditions or with due notice to the LF at other times. NEP shall exercise such right in accordance with Good Utility Practice. The switch shall be gang operated, have a visible break when open, and be capable of being locked open, tagged and grounded on NEP side by NEP personnel. The switch shall be of a manufacture and type generally accepted for use by NEP.

C. Protective relaying control circuits shall be DC powered from a station battery. Solid state relays shall be self powered or DC powered from a station battery.

D. CT ratios and accuracy classes shall be chosen such that secondary current is less than 100 amperes and transformation errors are less than 10% under maximum fault conditions.

E. All protective relays required by this Policy and Practices shall meet ANSI/IEEE standard C37.90 and be of a manufacture and type generally accepted for use by NEP.

F. Protective relays provided by the LF as required per this Policy and Practices shall be sufficiently redundant and functionally separate so as to provide adequate protection, as determined by NEP, upon the failure of any one component. The use of a single all-inclusive relay package is not acceptable.

G. NEP may require the LF to provide two independent, redundant relaying systems in accordance with NPCC Criteria for the Protection of the Bulk Power System if the interconnection is to the Bulk Power System or if it is determined that delayed clearing of faults within the LF adversely affects the Bulk Power System.

H. A direct transfer tripping system, if provided, shall use equipment generally accepted for use by NEP and shall, at the option of NEP, use dual channels.

4.) REQUIREMENTS FOR PROTECTION OF THE TRANSMISSION SYSTEM

A. The LF must provide protective relays to detect any faults, whether phase-to-phase or phase-to-ground within the LF, and isolate the LF from NEP's line(s) such that the following criteria are met, as determined by NEP:

- The existing sensitivity of fault detection is not substantially degraded.
- The existing speed of fault clearing is not substantially degraded.
- The coordination margin between relays is not substantially reduced.
- The sustained unfaulted phase voltage during a line-to-ground fault is not increased beyond 1.25 times the normal phase-to-ground voltage. (This value may be further reduced if required to coordinate with existing system insulation levels and overvoltage protection.)
- Non-directional line relays will not operate for faults external to the line due to the LF's contribution.
- Proper settings for existing relays are achievable within their ranges.

NEP may perform engineering studies to evaluate the LF's protection compliance with respect to the above and may make recommendations to the LF on methods to achieve compliance.

If, due to the interconnection of the LF to NEP's system, any of the above criteria are violated for NEP's facilities or for the facilities of others connected to NEP's system, NEP shall have the right to require the

LF to pay for the purchase, installation, replacement or modification of protective equipment to eliminate the violation and restore the level of protection existing prior to the interconnection. This may include the addition of pilot relaying systems involving communications between all terminals. Where such action is deemed necessary by NEP, NEP will, where possible, permit the LF to choose among two or more options for meeting NEP's requirements as described in this Policy and Practices.

B. The LF is responsible for procuring any communications channels necessary between the LF and NEP's stations and for providing protection from transients and overvoltages at all ends of these communication channels.

C. The LF may be required to use high speed protection if time-delayed protection would result in degradation in the existing sensitivity or speed of the protection systems on NEP's lines.

D. The LF may be required to provide local breaker failure protection which may include direct transfer tripping to NEP's line terminal(s) in order to detect and clear faults within the LF that cannot be detected by NEP's back-up protection.

5.) REQUIREMENTS FOR PROTECTION OF THE TRANSMISSION SYSTEM: FACILITIES HAVING SOURCES

If it is possible for the LF to be a source of current flow into NEP's system, either due to generation within the LF system or due to connections within the LF system to other sources, the LF must provide protective relays to detect any faults, whether phase-to-phase or phase-to-ground on NEP's lines or within the LF, and isolate the LF from NEP's line(s) per the requirement of Section 4 above and the following:

A. A control interlock scheme that detects voltage on NEP's line(s) shall be used to prevent an interconnection breaker from closing to energize NEP's line(s).

B. A voltage transformer shall be provided by the LF, connected to NEP side of the interconnecting breaker. The voltage from this VT shall be used in the interlock as specified in Section 5A above. If the LF's connection is ungrounded at NEP voltage, this VT shall be a single three-phase device or three single-phase devices connected from each phase to ground, rated for phase-to-phase voltage and provided with two secondary windings. One winding shall be connected in open delta, have a loading resistor to prevent ferroresonance, and be used for the relay specified in Section 5C below.

C. If the LF's connection to NEP's system is un-grounded, the LF shall provide a zero sequence overvoltage relay fed from the open delta of the three phase VT specified in Section 5B above.

D. NEP's lines generally have automatic reclosing following a trip with reclosing times as short as five seconds and without regard to whether the LF is keeping the circuit energized. The LF is responsible for protecting its equipment from being reconnected out of synchronism with NEP's system by an automatic line reclosure operation. The LF may choose to install additional equipment such as direct transfer tripping from NEP's station(s) to insure the LF is off the line prior to the line reclosing.

6.) REQUIREMENTS FOR EMERGENCY LOAD REDUCTION

A. The LF shall provide a manual load shed lockout relay to trip and block closing of selected load feeders. This relay shall be operated via a signal sent from an area dispatching center to a remote terminal unit (RTU) provided by the LF and shall be manually reset. The selection of feeders to trip shall be in conformance with NPCC Emergency Operation Criteria and determined by the area control authority. Alternatively, the LF may elect to provide compensatory load reduction through contractual arrangements with other area customers or by other means.

B. During system conditions where local area load exceeds generation, NPCC Emergency Operation Criteria requires a program of phased automatic underfrequency load shedding of up to 25% of area load to assist in arresting frequency decay and to minimize the possibility of system collapse. In conformance to these criteria, the LF shall provide an underfrequency relay with a lockout function to trip and block closing of selected load feeders. Feeders so shed shall not be re-energized without the express permission of the area control authority. If desired, the LF may use the RTU specified in Section 6A above to receive a signal sent from an area dispatching center that would reset the lockout function and permit automatic restoration of the feeders. The underfrequency settings and the selection of feeders shall be in conformance with these Criteria and determined by the area control authority. Alternatively, the LF may elect to provide compensatory load reduction to conform with the requirements of this Section through contractual arrangements with other area customers or by other means.

C. The LF shall provide a voltage reduction function to reduce the feeder voltage regulation set point by 5% for all load feeders. This function shall be operated via a signal sent from an area dispatching center to an RTU provided by the LF and shall be remotely reset from the dispatching center or self reset in 4 hours.

D. Depending on the point of connection of the LF to NEP's system, NEP may require a dead station tripping function to disconnect the LF from NEP's lines following six minutes of de-energized NEP lines in order to assist in restoration of service following an area or system wide shutdown.

7.) PROTECTION SYSTEM TESTING AND MAINTENANCE

A. NEP shall have the right to witness the testing of protective relays and control circuits required by this Policy and Practices at the completion of construction and to receive a copy of all test data. The LF shall provide NEP with at least a one week notice prior to the final scheduling of these tests. Testing shall consist of:

- CT and CT circuit polarity, ratio, insulation, excitation, continuity and burden tests.
- VT and VT circuit polarity, ratio, insulation and continuity tests.
- Relay pick-up and time delay tests.
- Functional breaker trip tests from protective relays.
- Relay in-service test to check for proper phase rotation and magnitudes of applied currents and voltages.
- Breaker closing interlock tests.
- Other relay commissioning tests typically performed for the relay types involved.

B. The protective relays shall be tested and maintained by the LF on a periodic basis but not less than once every four years or as determined by NEP. The results of these tests shall be summarized by the LF and reported in writing to NEP.

For relays installed in accordance with the NPCC Criteria for the Protection of the Bulk Power System, maintenance intervals shall be in accordance with the NPCC Maintenance Criteria for Bulk Power System Protection. The status of conformance with the NPCC Maintenance Criteria for Bulk Power System Protection shall be reported in writing to NEP annually.

8.) CHANGES TO THE LF'S PROTECTION SYSTEM

The LF must provide NEP with reasonable advance notice of any proposed changes to be made to the protective relay system, relay settings, operating procedures or equipment that affect the interconnection. NEP will determine if such proposed changes require re-acceptance of the interconnection per the requirements of this Policy and Practices.

In the future, should NEP implement changes to the system to which the LF is interconnected, the LF will be responsible at its own expense for identifying and incorporating any necessary changes to its protection system. Those changes to the LF's protection system are subject to review and approval by NEP.

ATTACHMENT F

Local Service Agreement

Insurance Requirements

During the term of this Agreement, the interconnecting Transmission Customer, at its own cost and expense, shall procure and maintain insurance in the forms and amounts acceptable to NEP at the following minimum levels of coverage:

1) Statutory coverage for workers' compensation, and Employer's Liability Coverage with a limit no less than $500,000.00 per accident;

2) Comprehensive General Liability Coverage including Operations, Contractual Liability and Broad Form Property Damage Liability written with limits no less than $5,000,000.00 combined single limit for Bodily Injury Liability and Property Damage Liability; and

3) Automobile Liability for Bodily Injury and Property Damage to cover all vehicles used in connection with the work with limits no less than $1,000,000.00 combined single limit for Bodily Injury and Property Damage Injury.

Prior to commencing the work, the interconnecting Transmission Customer shall have its insurer furnish to NEP certificates of insurance evidencing the insurance coverage required above and the interconnecting Transmission Customer shall notify and send copies to NEP of any policies maintained hereunder written on a "claims-made" basis. NEP may at its discretion require the interconnecting Transmission Customer to maintain tail coverage for five years on all policies written on a "claims-made" basis.

Every contract of insurance providing the coverages required in this provision shall contain the following or equivalent clause: "No reduction, cancellation or expiration of the policy shall be effective until thirty (30) days from the date written notice thereof is actually received by the interconnecting Transmission Customer. Upon receipt of any notice of reduction, cancellation or expiration, the interconnecting Transmission Customer shall immediately notify NEP.

NEP and its Affiliates shall be named as additional insureds, as their interests may appear, on the Comprehensive General Liability and Automobile Liability policies described above.

The interconnecting Transmission Customer shall waive all rights of recovery against NEP for any loss or damage covered by said policies. Evidence of this requirement shall be noted on all certificates of insurance provided to NEP.

ATTACHMENT H

Methodology for Completing System Impact Study

When New England Power Company ("NEP") determines on a non-discriminatory basis that a System Impact Study is needed because its Transmission System will be inadequate to accommodate a request for service, the following outlines the study methodology that NEP will employ to estimate the transmission system impact of a request for firm Transmission Service and/or any Costs for System Redispatch, Direct Assignment Facilities or Network Upgrades that would be incurred in order to provide the requested transmission service.

1. **System Impact** will be estimated based on consideration of reliability requirements to

- meet obligations under agreements that predate the OATT;
- meet obligations of existing and pending Valid Requests under the OATT; and
- maintain thermal, voltage and stability system performance within acceptable regional practices

2. **Guidelines and Principles followed by NEP -** NEP is a Participating Transmission Owner under the TOA and the Tariff and a member of the NPCC. When performing the System Impact Study, NEP will apply the following, as amended and/or adopted from time to time.

- Good Utility Practice;
- Criteria rules and reliability standards applicable to the New England Transmission System;
- NPCC criteria and guidelines; and
- New England Power Service Company (or its successor) guides

3. **Transmission System Model Representation -** The Transmission System Model will be based on a library of loadflow cases prepared by the ISO for studies of the New England area. The models may include representations of other NPCC and neighboring systems. These loadflow cases include individual system model representations provided by members of the ISO and represent forecasted system conditions for up to ten years in to the future. This library of loadflow cases is maintained and updated as appropriate by the ISO, and is consistent with information filed under FERC Form 715. NEP will use system models that it deems appropriate for study of the Request for Service. Additional system models and operating conditions, including assumptions specific to a particular analysis, may be developed for conditions not available in the library of loadflow cases. The system models may be modified, if necessary, to include additional system information on load, transfers and configuration, as it becomes available.

4. System Conditions - Loading of all transmission system elements shall be less than normal ratings for precontingency conditions and less than long-term emergency (LTE) ratings for post-contingency conditions. Post-contingency loading above LTE rating and less than short-term emergency (STE) rating may be allowed where demonstrated that loading can be reduced below the LTE rating within 15 minutes.

Transmission system voltages shall be within the applicable design ratings of connected equipment for normal and emergency conditions. Normal and post-contingency voltages shall be in accordance with NEP and ISO standards.

5. Short Circuits - Transmission system short circuit currents shall be within the applicable equipment design ratings.

6. Study Analysis - System impact of the integration of new generators will be evaluated to meet the requirements of design, identified in the guidelines and principles under Item 2, to provide sufficient transmission capability to maintain stability and to maintain thermal and voltage levels of lines and equipment within applicable limits. The same applies to the evaluation of transmission and delivery service under this tariff.

7. Loss Evaluation - The impact of losses on the Transmission System will be taken into account in the System Impact Study to ensure Good Utility Practice in the design and operation of its system.

8. System Protection - Protection requirements will be evaluated by NEP.

9. Approvals - NEP will conduct the System Impact Study to ensure compliance with its planning and design policies and practices. However, the actions to be taken by the Parties to implement the recommendations of the System Impact Study are subject to approval under the ISO New England Operating Procedures or Section I.3.9 of the Tariff, as amended and/or adopted from time to time.

10. Study Scope and Reporting - The study will determine the impacts and identify changes required, if any, to NEP's existing Transmission System. NEP will provide the Eligible Customer with a written report of the physical interconnection alternative(s), required NEP system additions and/or modifications, if any, associated study grade cost estimates (+/-25%) and the results of the analysis.

ATTACHMENT I

Real Power Losses Factors

Voltage Class kV	Losses as a % of Energy Delivered
Stepdown transformer*	1.00
69	1.25**
34.5	1.98
23	2.61
15	4.18
5	4.34
Dist. Secondary	0.52

*The transformer that steps the voltage from the transmission level to the delivery level.

**The loss factor for the 69 kV level applies only when the Point of Delivery is not directly interconnected with the PTF.

Note: When multiple voltage levels are present between the Point of Delivery and the metering point, the loss factors are additive.

ATTACHMENT DAF

Direct Assignment Facilities

This Attachment applies to all transactions that utilize any Direct Assignment Facilities or any other charges specifically assigned to a customer by NEP under this Schedule or the OATT. The formula set forth in this Attachment, as it may be amended from time to time, represents the Direct Assignment Facilities Charge which a Transmission Customer or Network Customer (together, "Transmission Customer") will pay in addition to the other applicable charges specified herein.

The determination of the annual Direct Assignment Facilities Charges chargeable to a specific Transmission Customer or group of Transmission Customers shall be calculated by the Annual Facility Charge formulas set forth below for transmission and distribution facilities. In no event will the Annual Facilities Charge be less than $1,000 per calendar year.

TRANSMISSION

Determination of Annual Facilities Charges for Transmission Facilities

The basis for this charge is data of NEP. The Annual Facilities Charge for NEP and its New England Affiliates shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Transmission Carrying Charge, for the life of the facility.

The Gross Plant Investment will be the investment from the plant accounting records associated with the facility.

The average Annual Transmission Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment determined in accordance with Attachment RR, Section I. (A) (1) (a) to this Schedule.

To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Transmission Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I. (B), and I. (C) of Attachment RR to this Schedule.

If the Transmission Customer permanently terminates service prior to the normal expiration of its Service Agreement, the Transmission Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Section I. (A)(2) to this Schedule, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination.

Billings shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's accounting records.

DISTRIBUTION

Determination of the Annual Facilities Charge for Distribution Facilities

The basis for this charge is data of NEP's New England Affiliate(s) or any other Affiliate that shall assume ownership over the Facilities included under this attachment.

The Annual Facilities Charge shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Distribution Carrying Charge, for the life of the facility.

The Gross Plant Investment will be the investment from the plant accounting records associated with the facility.

The average Annual Distribution Carrying Charge shall be the Annual Distribution Revenue Requirement as determined in Attachment RR, Exhibit 1 to this Schedule, divided by the year-end balance of total distribution plant investment determined in accordance with Attachment RR, Exhibit 1, Section I. (A) (1) (a) to this Schedule.

To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Distribution Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I. (B), and I. (C) of Attachment RR, Exhibit 1 to this Schedule.

If the Transmission Customer permanently terminates service in advance of the term of its Service Agreement, the Transmission Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Exhibit 1, Section I.(A)(2) to this Schedule, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission’s regulations effective at the time of termination.

Billings in accordance with this Schedule shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP’s or its applicable New England Affiliate’s accounting records.

METERS

Determination of Annual Metering Charges

The Meter Maintenance Charge shall equal the product of NEP’s installed metering costs for the customer and the Meter Carrying Charge determined in Attachment OCC, Exhibit 3 to this Schedule.

In accordance with the Meter Carrying Charge referenced above, the Annual Metering Charges will be updated on May 31 each year to reflect costs from the prior calendar year.

If the customer makes a CIAC, then the carrying charge in Attachment OCC, Exhibit 3 to this Schedule, will be adjusted accordingly.

ATTACHMENT DS

Rolled-In Distribution Surcharge

The monthly Rolled-in Distribution Surcharge shall be (i) the monthly cost per kilowatt of $2.77, multiplied by (ii) the annual peak load of the Transmission Customer on the distribution system of NEP's applicable New England Affiliate(s) from the prior calendar year. Notwithstanding the foregoing, this provision will not apply to the Transmission Customer's Network Load taking service under the Specific Distribution Surcharge.

ATTACHMENT OCC

Other Charges & Credits

The following charges and credits may apply to a Transmission Customer or Network Customer, as applicable:

I. Monthly Demand Charge:

Pursuant to Section 24.1 of this Schedule, the Network Customer will pay a monthly charge determined by multiplying its Load Ratio Share by the NEP's Monthly Local Network Transmission Expense as calculated in accordance with Exhibit 2 of this Attachment.

II. Monthly Non-PTF Demand Charge:

Pursuant to Section 24.2 of this Schedule, the Network Customer will pay a monthly charge determined by multiplying its Non-PTF Load Ratio Share by the Monthly Non-PTF Transmission Expense calculated in accordance with Attachment RR to this Schedule.

III. Transformer Surcharge:

Pursuant to Section 24.3 of this Schedule, the Transmission Customer or Network Customer will pay a monthly surcharge computed in accordance with Exhibit 1 of this Attachment.

This charge shall be multiplied by the Network Customer's Annual Peak Load, from the prior calendar year (coinciding with the calendar year used to calculate the Transformer Surcharge) in Exhibit 1 of this Attachment.

IV. Meter Surcharge:

The monthly meter surcharge shall be computed in accordance with Exhibit 3 of this Attachment multiplied by the number of NEP meters necessary to measure the delivery of transmission service to the Transmission Customer or Network Customer.

V. Power Factor Penalty:

Pursuant to Section 20.1 of this Schedule, a Network Customer or Transmission Customer will pay a Monthly Power Factor Penalty of $0.62 multiplied by the customer's deficient kilovars.

VI. Specific Distribution Surcharge:

The monthly Specific Distribution Surcharge shall be available to the following Network Customers

Georgetown Municipal Light Dept.

Ipswich Municipal Light Dept.

Princeton Electric Light Dept.

Hull Municipal Lighting Plant

Granite State Electric

Green Mountain Power Corp.

Groveland Municipal Light Dept.

Merrimac Municipal Light Dept.

Rowley Municipal Light Dept.

The monthly Specific Distribution Surcharge shall equal $.70 per KW month multiplied by the customer's Annual Peak Load from the prior calendar year.

VII. Network Load Dispatch Surcharge:

The monthly Network Load Dispatch Surcharge shall equal the monthly Dispatching Expense, Account 561, as defined in Attachment RR, Section I.G. to this Schedule, less any revenue received by NEP from the ISO for load dispatching services, multiplied by the Network Customer's Load Ratio Share.

VIII. [Reserved]

IX. Network EPRI Credit:

The Network EPRI Credit shall be determined by multiplying the Monthly Transmission-Related EPRI Expenses by the customer's Non-PTF Network Load Ratio Share.

The Monthly Transmission-Related EPRI Expenses shall equal themonthly EPRI Expenses as recorded in Account 930.

X. [Reserved]

XI. Pre-1997 RNS Revenue Credit:

The Pre-1997 RNS Revenue Credit will apply in the subsequent month's billing for the period June 1, 2001 through March 1, 2008, unless the transitional arrangements for the period prior to March 1, 2008 are otherwise amended.

ATTACHMENT OCC

EXHIBIT 1

Transformer Surcharge

I. No later than May 31 of each calendar year, the Transformer Surcharge will be calculated based on the prior calendar year's annual costs. The annual costs for Transformation Facilities service shall be the year-end balance of transmission plant investment in transformers included in Attachment RR, Section I. (A)(1)(a) to this Schedule multiplied by the Average Annual Carrying Charge.

II. The Average Annual Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment included in Attachment RR, Section I. (A)(1)(a) to this Schedule.

III. To determine the monthly Transformer Surcharge rate, the annual costs for transformation service will be divided by the Annual Peak Loads of that portion of all Transmission Customers' or Network Customers' load receiving such transformation service under this Schedule, and further divided by 12.

ATTACHMENT OCC

EXHIBIT 2

Monthly Local Network Transmission Expense

I. The Monthly Local Network Transmission Expense shall be the monthly balance of PTF Transmission Plant investment included in Attachment RR, Section I. (A)(1)(a) to this Schedule multiplied by the Monthly Carrying Charge, less any revenue received from the ISO associated with transmission-related services provided under the OATT.

II. The Monthly Carrying Charge shall be the Monthly Transmission Revenue Requirement as determined in accordance with Attachment RR to this Schedule, excluding any revenue credits associated with Transmission-related revenues from the ISO and revenues under Section 24.1 of this Schedule and as specified in Attachment RR, Section I.(G) and (J) to this Schedule, divided by the monthly balance of Transmission Plant determined in accordance with Attachment RR, Section I.(A)(1)(a) to this Schedule.

ATTACHMENT OCC

EXHIBIT 3

Meter Surcharge

I. No later than May 31 of each calendar year, the Meter Surcharge will be calculated based on the prior calendar year's annual costs. The annual costs for metering service shall be the year-end balance of plant investment in meters included in Attachment RR, Section I. (A) (1) (a) to this Schedule multiplied by the Average Annual Carrying Charge.

II. The Average Annual Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of transmission plant investment included in Attachment RR, Section I.(A) (1) (a) to this Schedule.

III. To determine the monthly Meter Surcharge rate, the annual costs for meter service will be divided by the number of NEP-Owned Billing Meters and further divided by twelve. The number of NEP-Owned billing meters shall equal the total number of meters owned by NEP and used for billing purposes under NEP's tariffs for wholesale all requirements and firm and non-firm transmission services.

ATTACHMENT OCC

EXHIBIT 4

Pre-1997 RNS Revenue Credit

The respective Pre-1997 RNS Revenue Credit to Taunton Municipal Lighting Plant, Middleborough Gas and Electric Department and Pascoag Fire District will be equal to

$$\left[1 - \frac{\text{EUA RNS Rate}}{\text{Combined RNS Rate}}\right] * [\text{customer's payment for RNS}]$$

Where:

EUA RNS Rate is former Montaup's 1999 Pre-1997 RNS rate as calculated under the NEPOOL Tariff.

Combined RNS Rate is equal to:

(A*B) + (C*D) / (B+D)

Where:

A = EUA's 1999 Pre-1997 RNS Rate as calculated under the NEPOOL Tariff.

B = EUA's 1999 12 CP Network Load (MW) as calculated under the NEPOOL Tariff.

C = NEP's 1999 Pre-1997 RNS Rate as calculated under the NEPOOL Tariff.

D = NEP's 1999 12 CP Network Load (MW) as calculated under the NEPOOL Tariff.

ATTACHMENT RR

Transmission Revenue Requirements

The Transmission Revenue Requirement will be determined based on the calculation shown below. In determining the rate for Local Network Service, the Revenue Requirement calculation as set forth below will be determined on a monthly basis.

I. The Transmission Revenue Requirement shall equal the sum of NEP's (A) Return and Associated Income Taxes, (B) Transmission Depreciation Expense, (C) Transmission-Related Amortization of Loss on Reacquired Debt, (D) Transmission-Related Amortization of Investment Tax Credits, (E) Transmission-Related Amortization of FAS 109, (F) Transmission-Related Municipal Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission-Related Administrative and General Expense, (I) Transmission-Related Integrated Facilities Credit, (J) Transmission Revenue Credit, (K) Distribution-Related Integrated Facilities Credit, and plus (L) Billing Adjustments; plus (M) Reactive Power Expense; plus (N) Bad Debt Expense.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be (a) Transmission Plant, plus (b) Transmission-Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission-Related Construction Work in Progress, less (e) Transmission-Related Depreciation Reserve, less (f) Transmission-Related Accumulated Deferred Taxes, plus (g) Transmission-Related Loss on Reacquired Debt, plus (h) Other Regulatory Assets, less (i) Allowance for Funds Used During Construction (AFUDC) Regulatory Liability, plus (j) Transmission Prepayments, plus (k) Transmission Materials and Supplies, plus (l) Transmission-Related Cash Working Capital.

(a) Transmission Plant will equal the balance of NEP's Total Investment in Transmission Plant, plus NEP's Total Investment in Distribution Plant excluding NEP's capital leases in the Hydro-Quebec DC facilities (HQ leases). NEP's investment in PTF transmission plant and step-down transformers beyond NEP's Point of Delivery, including associated equipment, shall be included but stated separately. NEP's investment in wholesale metering, including associated equipment, shall also be included but stated separately.

(b) **Transmission-Related General Plant** shall equal NEP's balance of investment in General Plant excluding General Plant related to NEP's generation facilities as specifically identified in NEP's CTC.

(c) **Transmission Plant Held for Future Use** shall equal the balance of investment in FERC Account 105.

(d) **Transmission-Related Construction Work In Progress** shall equal the portion of NEP's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) **Transmission-Related Depreciation Reserve** shall equal the balance of Total Depreciation Reserve, excluding any generation-related depreciation reserve associated with assets identified in NEP's CTC.

(f) **Transmission-Related Accumulated Deferred Taxes** shall equal NEP's balance of Total Accumulated Deferred Income Taxes, excluding any Accumulated Deferred Taxes associated with non-utility assets or generation facilities as identified in the CTC.

(g) **Transmission-Related Loss on Reacquired Debt** shall equal NEP's balance of Total Loss on Reacquired Debt excluding losses associated with NEP Generation as specifically identified in the CTC, or any generation-related losses associated with pollution control bonds.

(h) **Other Regulatory Assets** shall equal NEP's balance of FAS 109 excluding FAS 109 balances associated with NEP Generation as specifically identified in the CTC.

(i) **AFUDC Regulatory Liability** shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission orders.

(j) **Transmission Prepayments** shall equal NEP's balance of prepayments excluding any prepayments related to NEP's ongoing generation-related activities.

(k) **Transmission Materials and Supplies** shall equal NEP's balance of Transmission-related Materials and Supplies.

(l) **Transmission-Related Cash Working Capital** shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense and Transmission-Related Administrative and General Expense.

2. **Cost of Capital Rate**

The Cost of Capital Rate will equal (a) NEP's Weighted Cost of Capital, plus (b) the Yankee Adjustments plus (c) Federal Income Tax plus (d) State Income Tax.

(a) **The Weighted Cost of Capital** will be calculated based upon the capital structure at the end of each month and will equal the sum of:

(i) **the long-term debt component**, which equals the product of the actual weighted average embedded cost to maturity of NEP's long-term debt excluding any debt associated with pollution control bonds then outstanding and the ratio that long-term debt is to NEP's total capital less the end-of-year investment in Yankee Units.

(ii) **the preferred stock component**, which equals the product of the actual weighted average embedded cost to maturity of NEP's preferred stock then outstanding and the ratio that preferred stock is to NEP's total capital less the end-of-year investment in Yankee Units.

(iii) **the return on equity component (ROE),** which equals the product of the allowed based ROE of 10.57% and the ratio that common equity is to NEP's total capital less the end-of-year investment in Yankee Units.

For purposes of implementing the exclusion of the FERC-approved adders from Section J. below, the following ROEs will be applied to the corresponding investment:

post-2003 to pre-2009 PTF transmission plant investment in Regional System Plan approved by ISO-NE	11.74%%

remaining PTF transmission plant investment	11.07%
remaining transmission plant investment	10.57%

plus any ROE incentive approved by the FERC under Order No. 679 for other plant investments.[2]

(b) **The Yankee Adjustment** shall be calculated in accordance with FERC Opinion Nos. 49 and 49(a) issued in NEP's R-10 rate case and FERC Opinion No. 158 issued in NEP's W-3 rate case.

(c) **Federal Income Tax** shall equal

$$\frac{A \times FT}{1 - FT}$$

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 Section (I)(A)(2)(a)(ii), and Section (I)(A)(2)(a)(iii) above.

(d) **State Income Tax** shall equal

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

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is the rate determined in Section (I)(A)(2)(c) above.

B. **Transmission Depreciation Expense** shall equal the Depreciation Expense associated with the Transmission Plant, Transmission-Related General Plant and Transmission Plant Held for Future Use as described in Sections I.A.(a)(1), (b) and (c), less the amortization of AFUDC regulatory credit as recorded in FERC Account 407.4.

C. **Transmission-Related Amortization of Loss on Reacquired Debt** shall equal NEP's Amortization of the balance on Loss on Reacquired Debt as defined in Section I.A.(1)(f).

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

D. **Transmission-Related Amortization of Investment Tax Credits** shall equal NEP's Amortization of Investment Tax Credits, excluding any ITC credits specifically identified as generation-related in NEP's CTC.

E. **Transmission-Related Amortization of FAS 109** shall equal the Amortization of NEP's Balance of FAS 109, as identified in Section I.A.(1)(q) over a ten-year period beginning on the Divestiture Date of NEP's Generating Assets as defined in the CTC.

F. **Transmission-Related Municipal Tax Expense** shall equal NEP's total municipal tax expense excluding specifically identified generation-related municipal taxes or payments in lieu of such generation-related municipal taxes.

G. **Transmission Operation and Maintenance Expense** shall equal all expenses charged to FERC Account Numbers 560 through 598. Account Number 565, Transmission by Others, shall only include those expenses in support of facilities that are integrated with NEP's Transmission System or other transmission systems. Transmission Operation and Maintenance Expense shall include any expenses associated with transmission-related administrative services provided by the ISO and the expenses associated with providing Transmission Customers with the Pre-1997 Revenue Credit as described in Attachment OCC to this Schedule.

H. **Transmission-Related Administrative and General Expenses** shall equal NEP's Administrative and General Expenses, less Production-related Administrative and General Expense associated with joint-owned production units, plus Payroll Taxes,

I. **Transmission-Related Integrated Facilities Credit** shall equal NEP's transmission payments to its New England Affiliates for use of the integrated transmission facilities of those New England Affiliates.

J. **Transmission Revenue Credit** shall equal NEP's total transmission revenue, FERC Account Number 456, transmission-related sub-accounts of 447, and those revenues received from the ISO associated with the provision of transmission services under the OATT excluding the revenue received under the terms set forth in Section 24.2 of this Schedule, excluding any revenue received for the Hydro-Quebec DC facilities, excluding any revenue directly credited to Network Customers under Section 24.11 of this Schedule, excluding distribution revenues associated with expenses that have been excluded from

NEP's Transmission Revenue Requirement, and excluding any incremental revenues associated with FERC-approved adders for RTO participation and new transmission investment in accordance with Section II.A.2.(a)(iii) of Attachment F under the OATT . To the extent that NEP's transmission-related revenue under FERC Electric Tariff No. 1 is not reflected in the above-reference accounts on or after July 9, 1996, such revenue will be imputed under the formula set forth in the OATT and included in the Transmission Revenue Credit in accordance with the above specifications. Any Transmission Revenue Credit related to Section 24.1 of this Schedule shall be stated separately. Any revenue from the ISO associated with the provision of transmission service under the OATT, shall also be included but stated separately.

K. **Distribution-Related Integrated Facilities Credit** shall be equal to the credit applied to the purchased power bill of Massachusetts Electric Company under NEP's Tariff No. 1 for use of its distribution facilities used in support of wholesale transactions.

L. **Billing Adjustments** shall be plus or minus any billing adjustments from the prior transmission billing periods, including ISO adjustments. Billing adjustments shall include, but not be limited to, adjustments due to metering errors, corrections to any value included in this Attachment RR, or the Load Ratio Share. Such adjustments may be corrected prospectively. However, if the error is substantial, or substantially affects an individual Network or Transmission Customer, NEP reserves the right to credit and rebill customers for each affected billing month in which the error occurred.

M. **Reactive Power Expense** shall be set at zero as of the Second Effective Date, as defined in the NEPOOL Agreement.

N. **Bad Debt Expense** shall be the bad debt expense as reported in Account 904 related to transmission billing.

O. **Miscellaneous Provisions** In the event that the FERC accounts listed above are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

EXHIBIT 1

Distribution Cost of Service

Pursuant to Attachment DAF to this Schedule, the Distribution Cost of Service shall be calculated as follows for the applicable New England Affiliate:

I. The Primary Distribution System Cost of Service shall equal the sum of (A) Return and Associated Income Taxes, (B) Primary Depreciation Expense, (C) Primary Related Amortization of Loss on Reacquired Debt, (D) Primary Related Amortization of Investment Tax Credits, (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, (G) Primary Related Administrative and General Expense, and (H) Primary Revenue Credit.

A. Return and Associated Income Taxes shall equal the product of the Primary Investment Base and the Cost of Capital Rate.

(1) Primary Investment Base will be (a) Total Primary Distribution Plant, plus (b) Primary Related General Plant, plus (c) Primary Plant Held for Future Use, less (d) Primary Depreciation Reserve, less (e) Primary Related Accumulated Deferred Income Taxes, plus (f) Primary Related Loss on Reacquired Debt, plus (g) Other Regulatory Assets, plus (h) Primary Materials and Supplies, plus (i) Primary Related Prepayments, plus (j) Primary Related Cash Working Capital.

(a) Total Primary Distribution Plant shall equal the New England Affiliate's Plant Accounts 360 to 373 multiplied by allocation factors from the Distribution Engineering Study.

(b) Primary Related General Plant shall equal the New England Affiliate's Investment in General Plant, multiplied by the Primary Wages & Salaries Allocation Factor. The Primary Wages & Salaries Allocation Factor shall equal the ratio of Total Distribution Wages & Salaries to the Total New England Affiliate's Wages & Salaries excluding A&G, multiplied by the ratio of Primary Distribution related O&M to Total Distribution O&M (Primary O&M Allocation Factor).

(c) Primary Plant Held for Future Use shall equal the New England Affiliate's Account 105, multiplied by the Primary Land Allocation Factor from the Distribution Engineering Study.

(d) **Primary Depreciation Reserve** shall equal the New England Affiliate's Depreciation Reserve multiplied by the ratio of Primary Depreciable Distribution Plant to Total Depreciable Distribution Plant (Primary Depreciable Plant Allocation Factor), plus an allocation of average General Plant Depreciation Reserve calculated by multiplying beginning and end of year General Plant Depreciation Reserve by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

(e) **Primary Related Accumulated Deferred Income Taxes** shall equal the Total Accumulated Deferred Income Taxes, multiplied by the ratio of average Primary Plant in Service to average Total Plant in Service excluding General Plant (Primary Plant Allocation Factor).

(f) **Primary Related Loss on Reacquired Debt** shall equal the Total Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

(g) **Other Regulatory Assets** shall equal the New England Affiliate's balance of FAS 106, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b), plus the New England Affiliate's balance of FAS 109, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(c) above.

(h) **Primary Materials and Supplies** shall equal the New England Affiliate's Distribution Plant Materials and Supplies, multiplied by the Primary O&M Allocation Factor as described in Section (I)(A)(1)(b) above.

(i) **Primary Related Prepayments** shall equal the New England Affiliate's Prepayments, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b) above.

(j) **Primary Related Cash Working Capital** shall be a 45 day allowance or 12.5% of Primary Operation and Maintenance Expense and Primary Related Administrative and General Expense.

(2) **Cost of Capital Rate** will equal (a) the New England Affiliate's Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) 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) **the long-term debt component**, which equals the product of the actual dollar weighted average embedded cost to maturity of the New England Affiliate's long-term debt then outstanding and the ratio that long-term debt is to the New England Affiliate's total capital.

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

iii) **the return on equity component**, which equals the product of 10.57% and the ratio that common equity is to the New England Affiliate's total capital.

(b) **Federal Income Tax** shall equal

$$\frac{A \times FT}{1-FT}$$

where FT is the Federal Income Tax Rate and A the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above.

(c) **State Income Tax** shall equal

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

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is Federal Income Tax as determined in Section (I)(A)(2)(b) above.

B. **Primary Depreciation Expense** shall equal Depreciation Expense for Distribution Plant, multiplied by the Primary Depreciable Plant Allocation Factor as described in Section (I)(A)(1)(d) above, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

C. **Primary Related Amortization of Loss on Reacquired Debt** shall equal the New England Affiliate's Amortization of Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

D. **Primary Related Amortization of Investment Tax Credits** shall equal the New England Affiliate's Amortization of Investment Tax Credits, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

E. **Primary Related Municipal Tax Expense** shall equal a pro-rata share of the New England Affiliate's total municipal taxes allocated by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

F. **Primary Operation and Maintenance Expense** shall the sum of all expenses charged to FERC Account Numbers 580 through 598, allocated to Primary as indicated by the Distribution Engineering Study.

G. **Primary Related Administrative and General Expenses** shall equal the New England Affiliate's Administrative and General Expenses, plus Payroll Taxes, multiplied by the Primary Wages & Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

ATTACHMENT L

Creditworthiness Policy

1. Introduction & Applicability

This policy establishes creditworthiness standards for transmission service and/or interconnection service customers ("Customers") entering into new, amended or assigned service agreements with NEP under the ISO-NE OATT. The following describes NEP's qualitative and quantitative credit review procedures and the types of security that are acceptable to NEP to protect against the risk of default.

2. Information Requirements

For purposes of determining the ability of a Customer to meet its obligations, NEP may require the Customer to submit financial information for the credit review, including credit ratings, credit reports and audited financial statements. In addition, the following factors may be considered in evaluation of the Customer's creditworthiness: applicant's history; nature of organization and operating environment; management; contractual obligations; governance, financial / accounting policies, risk management and credit policies; market risk including price exposures, credit exposures, and operational exposures; and event risk. All information required under this Attachment should be forwarded to the NEP account manager as specified on the NEP OASIS website.

3. Creditworthiness Evaluation

NEP will evaluate the creditworthiness of Customers entering into new or amended transmission or interconnection service agreements with NEP in order to assess a Customer's credit risk relative to the exposure or "Total Outstanding Obligation" as defined in Section 3.1 below, created by the transaction or transactions that NEP has with the Customer.

3.1 Total Outstanding Obligation

The Customer's Total Outstanding Obligation to NEP will be the sum total of the following components:

3.1.1 If the Customer is making payments to NEP for ongoing expenses (including, but not limited to, O&M expenses related to interconnections or other monthly charges such as monthly transmission charges under Schedule 21-NEP of the ISO-NE OATT) the Customer will be required to provide security pursuant to Section 3.2 below, for four months' worth of the Customer's average payment obligation for such charges

3.1.2 Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a Contribution in Aid of Construction ("CIAC") or transfers ownership of facilities to NEP for transmission or interconnection facilities that are to be constructed on behalf of a Customer at the Customer's sole expense, and NEP determines in good faith that the receipt of CIAC payments or property from the Customer are non-taxable, NEP will require a form of security from the Customer pursuant to Section 3.2 below for the amount of the potential tax liability to NEP that would occur if such facilities were deemed taxable.

3.1.3 Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a formula rate over time for return of and on the cost of capital incurred by NEP on behalf of a Customer at the Customer's sole expense, the Customer will be required to provide security pursuant to Section 3.2 below, for the unamortized balance of plant in service reserved for the sole use of the Customer.

3.2 Creditworthiness Requirements

A Customer will be considered creditworthy upon satisfying at least one of the following conditions, or a combination of those conditions, at the time that the Customer enters into a transmission or interconnection service agreement and for so long as the Customer maintains satisfaction of at least one of these conditions for any outstanding obligations thereunder:

3.2.1 The Customer maintains a minimum credit rating of BBB from Standard & Poor's Long-term Issuer Credit Rating or Baa2 from Moody's Investors Service Long-term Issuer Credit Rating, so long as the Customer's Total Outstanding Obligation plus any other unsecured obligation with NEP and its Affiliates does not exceed the Credit Limits discussed in Section 5 below.[3] If unrated, the Customer's financial statements will be reviewed to determine an equivalent rating based on the Customer's unsecured credit limits and/or financial statements.

3.2.2 The Customer provides and maintains in effect during the term of and until full and final payment and performance of the service agreement an unconditional and irrevocable Letter of Credit for the Total Outstanding Obligation in the form and substance and issued by a bank acceptable to NEP. A draft, acceptable form letter of credit is posted on OASIS. Any such bank must satisfy the creditworthiness criteria described in 3.2.1 above.

3.2.3 The Customer's parent or an Affiliate company satisfies the creditworthiness criteria described in 3.2.1 above and, subject to the Credit Limits stated in Section 4 below, such company submits to NEP and maintains in effect a Letter of Guaranty acceptable to NEP as to amount, form and substance for the term of and until full and final payment and performance of the service agreement.

3.2.4 The Customer is a municipal that is a member of the Massachusetts Municipal Wholesale Electric Cooperative (MMWEC). In such instances, MMWEC must meet the criteria set out in 3.2.1 or 3.2.2 above and provide to NEP a Letter of Guaranty that MMWEC will be unconditionally responsible for all financial obligations associated with the Customer's receipt of transmission or interconnection service from NEP.

3.2.5 The Customer makes an advance payment to NEP in immediately available funds for the Total Outstanding Obligation.

If, at any time, the credit rating of the Customer, Customer's bank, or Customer's parent or Affiliate providing the Guaranty as set out in 3.2.1, 3.2.2 or 3.2.3 above falls below investment grade (BBB- from Standard and Poor's and or Baa3 from Moody's), the Customer will be required to provide (i) notification to NEP within 10 days and, (ii) another form of security acceptable to NEP, as described in this Section 3.2, within 30 days.

4. Customer Costs Requiring Prepayment

[3] When NEP reviews a Customer's rating from two or more rating agencies and a split rating is present, the lower debt rating will apply. In the event that the Customer only has a rating from either Standard & Poor's or Moody's Investors Service, a rating from Duff & Phelps or Fitch and Weiss may also be used with acceptable ratings equivalent to those from either Standard and Poor's or Moody's Investors Service.

Whenever, in accordance with the provisions of the ISO-NE OATT, a Customer pays a CIAC for transmission or interconnection facilities to be constructed by NEP on behalf of a Customer at the Customer's sole expense, the Customer will have the option to (i) prepay the CIAC in immediately available funds to NEP, or (ii) make periodic CIAC progress payments, as defined in the Customer's service agreement, to prepay in increments capital costs scheduled to be incurred by NEP. If NEP determines in good faith that such payments or property transfers made by the Customer should be reported as income subject to taxation, the Customer shall also prepay all costs associated with the cost consequences of the current tax liability imposed on NEP by those facilities (the "Tax Gross- up").

5. Credit Limits

NEP reserves the right to limit the total amount of unsecured credit extended to a Customer under 3.2.1 and 3.2.3 above such that the sum of all unsecured credit that such Customer has with NEP and its Affiliates, including the Total Outstanding Obligation, shall not exceed the Credit Limits defined below. Such limitations are based on an assessment of the Customer's or its Guarantor's credit rating and the net worth of the Customer's or its Guarantor's assets.

Standard and Poor's (or Equivalent) Rating	Unsecured Credit Limit as Percent of Customer's or Guarantor's Tangible Net Worth
A and above	1.0%
A-	0.5%
BBB+	0.2%
BBB	0.1%
BBB-	0.0%

6. Contesting Creditworthiness Determinations

A Customer may contest NEP's determination of creditworthiness by submitting a written request to NEP for re-evaluation within 20 calendar days of being notified of the creditworthiness determination. Such request should provide information supporting the basis for a request to re-evaluate the Customer's creditworthiness. NEP will review and respond to the request within 20 calendar days.

7. Process for Changing Credit Requirements

In the event that NEP plans to revise its requirements for credit levels or collateral requirements as detailed in this Attachment L, NEP shall submit such changes in a filing to the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act. NEP shall follow the notification requirements pursuant to Section 3.04(a) of the Transmission Operating Agreement and reflected herein.

7.1 General Notification Process

7.1.1 NEP shall provide written notification to ISO-NE and stakeholders of any filing described above, at least 30 days in advance of such filing. Filing notifications shall include a detailed description of the filing, including a redlined document containing revised change(s) to the Creditworthiness Policy. NEP shall consult with interested stakeholders upon request.

7.1.2 Following Commission acceptance of such filing and upon the effective date, NEP shall revise its Attachment L Creditworthiness Policy and an updated version of Schedule 21-NEP shall be posted on the ISO-NE website.

7.2 Customer Responsibility

7.2.1 Upon the effective date of any revision to these creditworthiness requirements or upon the date of the Commission's order accepting such revisions, whichever is later, the Customer shall have 30 days to forward updated financial information to NEP and indicate whether the revised creditworthiness requirements impair the Customer's ability to comply with the revised requirements. In such cases, the Customer must take all reasonable steps to comply with the revised requirements of the Creditworthiness Policy within 45 days of the effective date of the change.

7.3 Notification for Active Customers

7.3.1 Active Customers are defined as any current Customer that has a Service Agreement currently in effect and has posted an irrevocable letter of credit, letter of guaranty or prepayment in accordance with Sections 3.2.2, 3.2.3, 3.2.4, or 3.2.5, above.

7.3.2 All Active Customers will be served with copies of any filing submitted to the Commission to modify the NEP's creditworthiness requirements.

8. Suspension of Service

NEP may, immediately suspend service (with notification to Commission) to a customer, and may initiate proceedings with Commission to terminate service, if the customer does not meet the terms described in this Attachment. A customer is not obligated to pay for Transmission Service that is not provided as a result of a suspension of service.

ATTACHMENT S-1

Local Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area over Non-PTF. The Transmission Customer or Network Customer must purchase this service from NEP. The charges for Scheduling, System Control and Dispatch Service shall be based on the Local Network Load Dispatch Surcharge set forth in Attachment OCC to this Schedule. To the extent the ISO performs this service for NEP, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to NEP by the ISO.

PUC 3-2

Request:

Please provide a copy of the FERC letter accepting the original Local Service Agreement between New England Power Company (NEP) and Narragansett Electric pertaining to the BITS project, and a copy of the original filings made by National Grid in connection with seeking FERC acceptance.

Response:

See copy of the FERC letter accepting the original Local Service Agreement attached hereto and made a part hereof as Attachment PUC 3-2-1.

See copy of the original filing transmittal letter attached hereto and made a part hereof as Attachment PUC 3-2-2. See what were intended to be clean and marked tariff sheets submitted with the filing attached hereto and made a part hereof as Attachments PUC 3-2-3 and PUC 3-2-4.[1]

[1] Note that due to an administrative oversight, the marked tariff attachments showing the proposed revisions to the LSAs in the original Local Service Agreement filing were omitted from the filing which is why PUC 3-2-3 and PUC 3-2-4 are identical. The Filing Parties subsequently resubmitted the filing with its original transmittal letter and a complete set of the attachments specified in that letter as part of an errata filing. That errata filing has been included in response to PUC 3-3, specifically Attachments PUC 3-3-3-A through G.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

ISO New England Inc. and
New England Power Company
Docket No. ER15-1466-001

Issued: 6/22/15

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Alston & Bird LLP
The Atlantic Building
950 F Street NW
Washington, DC 20004

Attention: Monica Gonzalez, Esq.
Attorney for ISO New England Inc.

Kenneth G. Jaffe, Esq.
Attorney for New England Power Company

Reference: Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86

Dear Ms. Gonzalez and Mr. Jaffe:

On April 7, 2015, as amended on May 4, 2015, ISO New England Inc. (ISO-NE) and New England Power Company jointly submitted amendments to two executed Local Service Agreements (LSA). The first LSA is by and among NEP, Block Island Power Company (Block Island Power)[1], and ISO-NE, while the other is by and among NEP, The Narragansett Electric Company (Narragansett)[2] and ISO-NE. The revisions address the concern raised by the Rhode Island

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[1] ISO New England Inc., ISO New England Inc. Agreements and Contracts, Block Island LSA, LSA - TSA-NEP-83 NEP, Block Island Power and ISO-NE, 2.0.0.

[2] ISO New England Inc., ISO New England Inc. Agreements and Contracts, Narragansett LSA, LSA - TSA-NEP-86 NEP, Narragansett and ISO-NE, 2.0.0.

Division of Public Utilities and Carriers that the Block Island Transformation System Surcharge calculated under the LSAs did not fully comport with the Rhode Island General Law Section 39-26.7(f).

Pursuant to the authority delegated to the Director, Division of Electric Power Regulation – East, under 18 C.F.R. § 375.307, your submittal is accepted for filing, effective June 7, 2015, as requested.

The filings were noticed on April 7, 2015 and May 5, 2015, with comments, interventions, and protests due on or before April 28, 2015 and May 26, 2015, respectively. Pursuant to Rule 214 (18 C.F.R. § 385.214 (2014)), to the extent that any timely filed motions to intervene and any motion to intervene out-of-time were filed before the issuance date of this order, such interventions are granted. Granting late interventions at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties.

This acceptance for filing shall not be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in your filing; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the ISO-NE or NEP.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Kurt M. Longo, Director
Division of Electric Power
Regulation – East

April 7, 2015

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

Re: New England Power Company
Docket No. ER15-____-000
Filing of First Revised Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86 Under ISO-NE OATT

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] New England Power Company d/b/a National Grid ("NEP") joined by ISO New England Inc. ("ISO-NE") (together, the "Filing Parties")[3] submit amendments to the following two Local Service Agreements ("LSAs"):

(1) the LSA among NEP, Block Island Power Company ("BIPCO"), and ISO New England Inc. ("ISO-NE"), designated as First Revised Service Agreement No. TSA-NEP-83 under the ISO-NE OATT; and

(2) the LSA among NEP, The Narragansett Electric Company ("Narragansett"), and ISO-NE, designated as First Revised Service Agreement No. TSA-NEP-86 under the ISO-NE OATT.

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1 16 U.S.C. § 824d.

2 18 C.F.R. Part 35.

3 NEP, and not ISO-NE, has the FPA section 205 rights over Schedule 21-NEP of the ISO-NE Open Access Transmission Tariff ("OATT"), pursuant to which NEP offers and administers Local Service. ISO-NE does not offer or administer Local Service and joins this filing solely to fulfill its obligations to file Local Service Agreements on the applicable Participating Transmission Owner ("PTO"), in accordance with Article 3.03(d)(ii) of the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs. *See ISO New England Inc.*, 124 FERC ¶ 61,297 (2008).

The Filing Parties request that the Commission accept the LSAs effective 61 days after the date of this filing, *i.e.*, June 7, 2015

I. Background

The original LSAs were accepted by the Commission on September 2, 2014, by delegated letter order in Docket No. ER14-2514-000. The LSAs were executed in order to include the Town of New Shoreham Project under the integrated facilities provisions of NEP's FERC Electric Tariff No. 1 ("Tariff No. 1").[4] The Town of New Shoreham Project is a public policy project authorized and directed by a Rhode Island statute of the same name.[5] The statute directs that:

> it is in the public interest for the state to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the [Rhode Island] mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland.[6]

The statute authorizes and sets forth a process for developing the Town of New Shoreham Project, an associated power purchase agreement, transmission arrangements, and recovery of related costs. It also permits Narragansett, at its option, to own, operate, or otherwise participate in the transmission cable project.[7]

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4 Pursuant to those integrated facilities provisions, NEP supports the cost of the transmission facilities of its affiliate Narragansett, and Narragansett makes its transmission facilities available to be controlled and operated by NEP so that the transmission facilities of NEP and NEP's New England distribution affiliates are operated on an integrated basis and made available for open access transmission service in accordance with the ISO-NE OATT.

5 Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7 (Supp. 2010).

6 *Id.*, § 39-26.1-7(a).

7 *Id.*, § 39-26.1-7(f). The statute specifies that "all costs incurred in the negotiation, administration, enforcement, transmission engineering associated with the design of the cable, and implementation of the project and agreement shall be recovered annually by the electric distribution company [*i.e.*, Narragansett] in electric distribution rates." *Id.*, § 39-26.1-7(d). The statute also directs that, should Narragansett own, operate, and maintain the cable, "the annual costs incurred by [Narragansett] directly or through transmission charges shall be recovered annually through a fully reconciling rate adjustment from customers of [Narragansett] and/or from the Block Island Power Company or its successor, subject to any federal approvals that may be required by law." *Id.*, § 39-26.1-7(f). Further, "[t]he revenue requirement for the annual cable costs shall be calculated in the same manner that the revenue requirement is calculated

The Deepwater Block Island Wind, LLC ("Block Island Wind") generation project, a 30-megawatt (nameplate) demonstration-scale offshore wind facility, is the offshore wind demonstration project described in the statute. Narragansett has agreed to construct, own, and operate the undersea cable between Block Island and the mainland and related facilities, which include a substation to be built on Block Island that will interconnect the Block Island Wind project to Narragansett's existing 34.5 kV system on the mainland. In addition, BIPCO, serving the Town of New Shoreham on Block Island, will interconnect to the same substation and will be electrically interconnected to the mainland for the first time by the same undersea cable. The cable will allow power to flow either from the Block Island Wind project to Block Island to the Rhode Island mainland, or from generators located on the mainland to Block Island, as needed. The Town of New Shoreham Project is currently estimated to be completed by late 2016.

As part of the package of Agreements necessary to implement the transaction and interconnect Block Island Wind to the mainland, NEP also filed, (1) a Large Generator Interconnection Agreement ("LGIA") with Block Island Wind which was accepted by the Commission by delegated letter order on September 2, 2014, in Docket No. ER14-2496-000 and (2) an amendment to Service Agreement No. 23 under NEP's Tariff No. 1 accepted by the Commission by delegated letter order on September 2, 2014, in Docket No. ER14-2493-000. NEP also terminated its previous Network Integration Transmission Service Agreement No. 108 with Narragansett which was part of the record in Docket No. ER14-2519.

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for other transmission facilities in Rhode Island for local network service under the jurisdiction of the federal energy regulatory commission." *Id.*

II. The LSAs

The LSAs being filed in this proceeding have been revised to address a concern raised by the Rhode Island Division of Public Utilities and Carriers ("Division") that the Block Island Transmission System ("BITS") Surcharge[8] calculated under the LSAs did not fully conform with the Rhode Island statute referenced above. Specifically, the Division was concerned that the calculation of the BIPCO Share Percentage did not fully comport with the Rhode Island General Law Section 39-26.7(f) which states:

> "The allocation of the costs related to the transmission cable through transmission rates or otherwise shall be structured so that the estimated impact on the typical residential customer bill for such transmission costs for customers in the Town of New Shoreham *shall be higher* than the estimated impact on the typical residential customer bill for customers on the mainland of the electric distribution company." (Emphasis added)

To address the issues raised by the Division, NEP modified the BITS Surcharge by introducing a collar to the calculation of the BIPCO Share Percentage such that the impact on the typical residential customer in the Town of New Shoreham cannot be lower than 120% of the impact on the typical residential customer of The Narragansett Electric Company. All parties have executed these First Revised LSAs to reflect that change. NEP is authorized to state the Division also supports this modification.

III. Effective Date

The Filing Parties request that the Commission accept the LSAs effective 61 days after the date of this filing, *i.e.*, June 7, 2015.

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[8] *See* the BITS Surcharge provisions set forth in Part II, Section 2(p) of the LSAs and a referenced attachment in each LSA.

IV. Attachments

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Executed First Revised Service Agreement No. TSA-NEP-83;
Attachment A-1	Marked comparison between First Revised Service Agreement No. TSA-NEP-83 and Original Local Service Agreement No. TSA-NEP-83.
Attachment B	Executed First Revised Service Agreement No. TSA-NEP-86; and
Attachment B-1	Marked comparison between First Revised Service Agreement No. TSA-NEP-86 and Original Service Agreement No. TSA-NEP-86.

V. Description of the Filing Parties and Communications

NEP is a wholly owned subsidiary of National Grid USA. NEP is a public utility subject to the Commission's jurisdiction that owns transmission facilities located in New England. NEP's primary business is the transmission of electricity at wholesale to electric utilities and municipalities in New England. NEP operates transmission facilities that it owns directly as well as certain transmission facilities owned by its distribution affiliates in New England pursuant to integrated facilities agreements under Tariff No. 1. NEP acts as the transmission provider for itself and its New England distribution affiliates. NEP is a PTO under the terms of the TOA by and among the New England PTOs and ISO-NE. All of NEP's transmission facilities, including those owned by its New England distribution affiliates, are subject to the operating authority of ISO-NE under the terms of the TOA and are available for open access transmission service under the terms of Section II of the ISO-NE Tariff.

ISO-NE is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. ISO-NE operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the ISO-NE Transmission, Markets and Services Tariff and the Transmission Operating Agreement with the New England transmission owners. In its capacity as an RTO, ISO-NE also has the objective to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC").

Communications and correspondence regarding this filing should be addressed to the following individuals:

NEP:

Daniel Galaburda
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and Director
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ISO-NE:

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(413) 535-4000
Fax: (413) 535-4379
mgonzalez@iso-ne.com

VI. Service

Copies of this filing have been served on Block Island Wind, Narragansett, BIPCO, the Rhode Island Division of Public Utilities and Carriers, and the Rhode Island Public Utilities Commission.

VII. Conclusion

For these reasons, the Filing Parties request that the Commission accept them effective 61 days from the date of filing, *i.e.*, June 7, 2015. Please contact the undersigned with any questions regarding this filing.

Respectfully submitted,

/s/ Kenneth G. Jaffe
Kenneth G. Jaffe
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Amanda C. Downey
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Service Company, Inc.
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Attorneys for New England Power Company d/b/a National Grid

/s/ Monica Gonzalez
Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Attorney for ISO New England Inc.

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), Block Island Power Company, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

  __ Firm

  __ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: Clifford R. McGinness
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

   a. Term of Service: See 2 above.

   b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
Initially up to 4.6 MW and 15TWh of Network Load

d. Description of Local Network Load:
Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
At the Transmission Owner's Affiliate's 34.5 kV substation on Block Island.
Note: The metering is on the 34.5 kV side and the Transmission Owner owns the meter.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:
1-34.5kV breaker, 1-34.5/4.16kV/2.4kV transformer, 5kV insulated line to customer substation and associated equipment.

j. Project name:

k. Interconnecting Transmission Customer:

l. **Location:**

m. **Transformer nameplate rating:**

n. **Interconnection point:**

At 34.5kV at the Transmission Owner's Affiliate's 34.5kV substation on Block Island.

o. **Additional facilities and/or associated equipment:**

p. **Service under this Local Service Agreement shall be subject to the following charges:**

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. **Additional terms and conditions:**

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room. Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5 kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: C.R. McGinnes V/President + COO 1/22/15
Name Title Date

C.R. McGINNES
Print Name

Transmission Owner:

By: William L Malee Authorized Representative 1/8/15
Name Title Date

William L Malee
Print Name

The ISO:

By: ______ V.P. System Planning 1/30/15
Name Title Date

______
Print Name

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Collar:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

THE NARRAGANSETT ELECTRIC COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), The Narragansett Electric Company d/b/a/ National Grid, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take

and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
The Narragansett Electric Company
Attn: Mary K. Smith
280 Melrose Street
Providence, RI 02907

Transmission Owner:
New England Power Company
Attention: Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205

of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.
2. Service shall commence on the later of: (l) the date that termination becomes effective for the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997, by and between New England Power Company and The Narragansett Electric Company, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on or after the date that Contract Termination Charges, defined and set forth in the Stipulation and Agreement and the Amendment to the Service Agreement between the Transmission Customer and Transmission Owner under the Transmission Owner's FERC Electric Tariff, Original Volume 1 filed on May 30, 1997 in Docket No. ER97-680-000 and conditionally approved by the Commission on November 26, 1997(the "Restructuring Agreements"), are fully recovered from the Transmission Customer. Following that date, service under this Local Service Agreement shall continue until modified or terminated upon the written consent of the parties or upon five years advance written notice by any party to the others.

3. Specifications for Local Network Service.

a. Term of Service: See 2 above.

b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
1.8 GW and 7800 GWh

d. Description of Local Network Load:

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
See Attachment 1

f. List of non-Network Resource(s), to the extent known:
None

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer has executed a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

As of the execution date of this Local Service Agreement, the Schedule 21-NEP charges include a:

- Monthly demand charge with PTF and non-PTF components
- Transformer surcharge
- Meter surcharge
- Network load dispatch surcharge
- Third party support payments
- Direct Assignment Facility charge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 2)

q. Additional terms and conditions:

This Local Service Agreement amends and replaces the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997 and entered into by and between New England Power Company and The Narragansett Electric Company for the purpose of implementing wholesale competition or retail access for the Transmission Customer's retail customers pursuant to the Rhode Island Restructuring Act of 1996 ("URA"). Pursuant to the NITS Agreement, the following terms and conditions will remain in effect under the terms of this Local Service Agreement:

(i) In the event that Transmission Customer is denied recovery in its rates for local distribution service of access charges sufficient to collect the full amount of the Contract Termination Charges billed to Transmission Customer, its successors or assigns, by Transmission Owner, its successors or assigns, Transmission Owner, its successors or assigns, providing service over the transmission facilities covered by this Local Service Agreement shall collect the unrecovered balance of the Contract Termination Charges as a surcharge under this Local Service Agreement to the Transmission Customer or to any consumer taking delivery of electric energy over the transmission or distribution facilities of the Transmission Customer.

(ii) The obligations under this Local Service Agreement may be assigned only with the express written consent of the other parties, which consent shall not be unreasonably withheld, provided, however, that the Transmission Owner shall not be obligated to consent to any assignment that adversely affects the ability of the Transmission Owner to recover from the Transmission Customer the payments required to be made under the Tariff, and this Local Service Agreement, including any Contract Termination Charges that may be billed to Transmission Customer pursuant to the paragraph above.

(iii) The Transmission Owner has agreed to terminate those requirements of its FERC Electric Tariff, Original Volume No. 1 ("Tariff No. 1") that obligate the Transmission Customer to buy all of its electricity requirements under Tariff No. 1 and Transmission Customer has agreed to pay Contract Termination Charges pursuant to the Restructuring Agreements.

(iv) In no event shall the Transmission Owner bypass the Transmission Customer's distribution facilities and interconnect directly with a retail customer.

(v) To the extent ISO New England, Inc. or NEPOOL does not directly bill the Transmission Customer, any charges by ISO New England, Inc. or NEPOOL specifically incurred by the Transmission Owner, as a result of services provided to the Transmission Customer, will be directly assigned to the Transmission Customer as provided for under Section 24.6 of Schedule 21-NEP. The Transmission Owner will determine the direct charges to the Transmission Customer on the basis of the Transmission Customer's contribution to the incurrence of those charges using the same allocation methodology used by ISO New

England, Inc. or NEPOOL to allocate those costs to the Transmission Owner.

4. Planned work schedule.

Estimated Time	
Milestone	Period For Completion
(Activity)	(# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service N/A

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) _________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone	Period For Completion
(Activity)	(# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: ____________________ President 1/12/15
Name Title Date

Timothy F. Horan
Print Name

Transmission Owner:

By: ____________________ Authorized Representative 1/12/15
Name Title Date

William L Malee
Print Name

The ISO:

By: ____________________ V.P. System Planning 1/21/15
Name Title Date

Stephen J. Rourke
Print Name

Attachment 1

The Narragansett Electric Company

Points of Delivery

Main District
Admiral Street Substation
Blackburn Substation
Bristol Substation
Clarkson Street Substation
Davisville Substation
Drumrock Substation
EMI Tiverton Station Service
Farnum Pike Substation
FPL RISEP Station Service
Franklin Square Substation
Johnston Substation
Kent County Substation
Kenyon Substation
Kilvert Substation
Lincoln Ave. Substation
Mink Street Substation
Old Baptist Road Substation
Phillipsdale Substation
Point Street Substation
Pontiac Substation
Putnam Pike
Sockanosset Substation
South Street Station
Tiverton Substation
Tower Hill Substation
Wampanoag Substation
Warren Substation
West Cranston Substation
West Kingston Substation
Wolf Hill Substation
Wood River Substation
Woonsocket Substation

Blackstone Valley
Nasonville B23 Line from W. Farnum
West Farnum tap off 174
Farnum off H 17 Line
Riverside - R9/J16/H17
Pawtucket No. 1 Station X3/P11/T7
Staples J16/Q10
Vallev R9P11
Washington V148 from Robinson Ave
Ocean State Power Station Service

Newport
Canonicus St. M13L14

Attachment 1

Metering Points (To the extent they differ from a Point of Delivery)

Main District
Pawtucket Power
Johnston Landfill
Valley Hydro
Cranston Landfill

Blackstone Valley
Roosevelt Hydro
Blackstone Hydro, Inc.
Blackstone Hydro Assoc.
Pawtucket #2 Hydro
Woonsocket Hydro

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO Share Percentage. The BIPCO Share Percentage shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar year as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy = 13,369,466 kWh

(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh
(4) Minimum Energy Ratio Share ((1)/(3)) =	0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh
(4) Maximum Energy Ratio Share ((1)/(3)) =	0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, the BIPCO Share Percentage in this example would be 0.19508%.

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21
ATTACHMENT A
FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), Block Island Power Company, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: Clifford R. McGinness
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

   a. Term of Service: See 2 above.

   b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
Initially up to 4.6 MW and 15TWh of Network Load

d. Description of Local Network Load:
Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
At the Transmission Owner's Affiliate's 34.5 kV substation on Block Island.
Note: The metering is on the 34.5 kV side and the Transmission Owner owns the meter.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:
1-34.5kV breaker, 1-34.5/4.16kV/2.4kV transformer, 5kV insulated line to customer substation and associated equipment.

j. Project name:

k. Interconnecting Transmission Customer:

l. **Location:**

m. **Transformer nameplate rating:**

n. **Interconnection point:**

At 34.5kV at the Transmission Owner's Affiliate's 34.5kV substation on Block Island.

o. **Additional facilities and/or associated equipment:**

p. **Service under this Local Service Agreement shall be subject to the following charges:**

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. **Additional terms and conditions:**

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room. Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5 kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable.

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.
Estimated Time

Milestone (Activity)	Period For Completion (# of months)

6. Payment schedule and costs.
(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: C.R. McGinnes V/President + COO 1/22/15
Name Title Date

C.R. McGINNES
Print Name

Transmission Owner:

By: William L Malee Authorized Representative 1/8/15
Name Title Date

William L Malee
Print Name

The ISO:

By: V.P. System Planning 1/30/15
Name Title Date

Print Name

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Collar:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

THE NARRAGANSETT ELECTRIC COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), The Narragansett Electric Company d/b/a/ National Grid, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take

and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
The Narragansett Electric Company
Attn: Mary K. Smith
280 Melrose Street
Providence, RI 02907

Transmission Owner:
New England Power Company
Attention: Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205

of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.
2. Service shall commence on the later of: (l) the date that termination becomes effective for the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997, by and between New England Power Company and The Narragansett Electric Company, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on or after the date that Contract Termination Charges, defined and set forth in the Stipulation and Agreement and the Amendment to the Service Agreement between the Transmission Customer and Transmission Owner under the Transmission Owner's FERC Electric Tariff, Original Volume 1 filed on May 30, 1997 in Docket No. ER97-680-000 and conditionally approved by the Commission on November 26, 1997(the "Restructuring Agreements"), are fully recovered from the Transmission Customer. Following that date, service under this Local Service Agreement shall continue until modified or terminated upon the written consent of the parties or upon five years advance written notice by any party to the others.

3. Specifications for Local Network Service.

a. Term of Service: See 2 above.

b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
1.8 GW and 7800 GWh

d. Description of Local Network Load:

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
See Attachment 1

f. List of non-Network Resource(s), to the extent known:
None

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer has executed a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

As of the execution date of this Local Service Agreement, the Schedule 21-NEP charges include a:

- Monthly demand charge with PTF and non-PTF components
- Transformer surcharge
- Meter surcharge
- Network load dispatch surcharge
- Third party support payments
- Direct Assignment Facility charge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 2)

q. Additional terms and conditions:

This Local Service Agreement amends and replaces the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997 and entered into by and between New England Power Company and The Narragansett Electric Company for the purpose of implementing wholesale competition or retail access for the Transmission Customer's retail customers pursuant to the Rhode Island Restructuring Act of 1996 ("URA"). Pursuant to the NITS Agreement, the following terms and conditions will remain in effect under the terms of this Local Service Agreement:

(i) In the event that Transmission Customer is denied recovery in its rates for local distribution service of access charges sufficient to collect the full amount of the Contract Termination Charges billed to Transmission Customer, its successors or assigns, by Transmission Owner, its successors or assigns, Transmission Owner, its successors or assigns, providing service over the transmission facilities covered by this Local Service Agreement shall collect the unrecovered balance of the Contract Termination Charges as a surcharge under this Local Service Agreement to the Transmission Customer or to any consumer taking delivery of electric energy over the transmission or distribution facilities of the Transmission Customer.

(ii) The obligations under this Local Service Agreement may be assigned only with the express written consent of the other parties, which consent shall not be unreasonably withheld, provided, however, that the Transmission Owner shall not be obligated to consent to any assignment that adversely affects the ability of the Transmission Owner to recover from the Transmission Customer the payments required to be made under the Tariff, and this Local Service Agreement, including any Contract Termination Charges that may be billed to Transmission Customer pursuant to the paragraph above.

(iii) The Transmission Owner has agreed to terminate those requirements of its FERC Electric Tariff, Original Volume No. 1 ("Tariff No. 1") that obligate the Transmission Customer to buy all of its electricity requirements under Tariff No. 1 and Transmission Customer has agreed to pay Contract Termination Charges pursuant to the Restructuring Agreements.

(iv) In no event shall the Transmission Owner bypass the Transmission Customer's distribution facilities and interconnect directly with a retail customer.

(v) To the extent ISO New England, Inc. or NEPOOL does not directly bill the Transmission Customer, any charges by ISO New England, Inc. or NEPOOL specifically incurred by the Transmission Owner, as a result of services provided to the Transmission Customer, will be directly assigned to the Transmission Customer as provided for under Section 24.6 of Schedule 21-NEP. The Transmission Owner will determine the direct charges to the Transmission Customer on the basis of the Transmission Customer's contribution to the incurrence of those charges using the same allocation methodology used by ISO New

England, Inc. or NEPOOL to allocate those costs to the Transmission Owner.

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service N/A

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time	
Milestone	Period For Completion
(Activity)	(# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: ____________ President 1/12/15
Name Title Date

Timothy F. Horan
Print Name

Transmission Owner:

By: William L Malee Authorized Representative 1/12/15
Name Title Date

William L Malee
Print Name

The ISO:

By: ____________ V.P. System Planning 1/21/15
Name Title Date

Stephen J. Rourke
Print Name

Attachment 1

The Narragansett Electric Company

Points of Delivery

Main District
Admiral Street Substation
Blackburn Substation
Bristol Substation
Clarkson Street Substation
Davisville Substation
Drumrock Substation
EMI Tiverton Station Service
Farnum Pike Substation
FPL RISEP Station Service
Franklin Square Substation
Johnston Substation
Kent County Substation
Kenyon Substation
Kilvert Substation
Lincoln Ave. Substation
Mink Street Substation
Old Baptist Road Substation
Phillipsdale Substation
Point Street Substation
Pontiac Substation
Putnam Pike
Sockanosset Substation
South Street Station
Tiverton Substation
Tower Hill Substation
Wampanoag Substation
Warren Substation
West Cranston Substation
West Kingston Substation
Wolf Hill Substation
Wood River Substation
Woonsocket Substation

Blackstone Valley
Nasonville B23 Line from W. Farnum
West Farnum tap off 174
Farnum off H 17 Line
Riverside - R9/J16/H17
Pawtucket No. 1 Station X3/P11/T7
Staples J16/Q10
Vallev R9P11
Washington V148 from Robinson Ave
Ocean State Power Station Service

Newport
Canonicus St. M13L14

Attachment 1

Metering Points (To the extent they differ from a Point of Delivery)

Main District
Pawtucket Power
Johnston Landfill
Valley Hydro
Cranston Landfill

Blackstone Valley
Roosevelt Hydro
Blackstone Hydro, Inc.
Blackstone Hydro Assoc.
Pawtucket #2 Hydro
Woonsocket Hydro

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO Share Percentage. The BIPCO Share Percentage shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar year as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy = 13,369,466 kWh

(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh
(4) Minimum Energy Ratio Share ((1)/(3)) =	0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh
(4) Maximum Energy Ratio Share ((1)/(3)) =	0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, the BIPCO Share Percentage in this example would be 0.19508%.

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

PUC 3-3

Request:

Please provide copies of the original Local Service Agreements (LSAs) (i) between NEP and Narragansett Electric and (ii) NEP and Block Island Power, and all other amended versions, including without limitation the current versions now in effect. Please also provide copies of all filing documents that were submitted in connection with the filing of any amended versions. Please also provide copies of any filings made by any intervening parties in each case.

Response:

See the following documents:

- Documents related to Docket No. ER14-2514-000 attached as Attachments PUC 3-3-1-A through H. This is the original filing for the LSAs between NEP and Block Island (designated as TSA-NEP-83) and NEP and Narragansett (designated as TSA-NEP-86).

    1. Transmittal Letter as Attachment PUC 3-3-1-A;
    2. Original LSA between NEP and Block Island (TSA-NEP-83) as Attachment PUC 3-3-1-B;
    3. Marked comparison between TSA-NEP-83 and ISO-NE OATT Form of Local Service Agreement as Attachment PUC 3-3-1-C;
    4. Original LSA between NEP and Narragansett (TSA-NEP-86) as Attachment PUC 3-3-1-D;
    5. Marked comparison between TSA-NEP-86 and ISO-NE OATT Form of Local Service Agreement as Attachment PUC 3-3-1-E;
    6. Doc-less Motion to Intervene by Deepwater Wind as Attachment PUC 3-3-1-F;
    7. Comment by Benjamin C. Riggs as Attachment PUC 3-3-1-G;
    8. Letter Order accepting filing as Attachment PUC 3-3-1-H;

PUC 3-3, page 2

- Documents related to Docket No. ER15-1466-000 attached as Attachments PUC 3-3-2-A through E2. This filing was intended to amend both TSA-NEP-83 and TSA-NEP-86.

    1. Transmittal Letter as Attachment PUC 3-3-2-A;

    2. TSA-NEP-83 (clean version) as Attachment PUC 3-3-2-B;

    3. Attachment A1: TSA-NEP-83 (redlined version) as Attachment PUC 3-3-2-C1. Note: This Attachment was not actually marked or redlined, and led to the subsequent filing in Docket No. ER15-1466-001; see Attachment PUC 3-3-2-C2.

    4. TSA-NEP-86 (clean version) as Attachment PUC 3-3-2-D;

    5. TSA-NEP-86 (redlined version) as Attachment PUC 3-3-2-E1. Note: This Attachment was not actually marked or redlined, and led to the subsequent filing in Docket No. ER15-1466-001; see Attachment PUC 3-3-2-E2.

- Documents related to Docket No. ER15-1466-001 attached as Attachments PUC 3-3-3-A through G. This was an amended filing to correct the redlines in Docket No. ER15-1466.

    1. Transmittal Letter as Attachment PUC 3-3-3-A;

    2. Transmittal Letter from ER15-1466-000 as Attachment PUC 3-3-3-B;

    3. TSA-NEP-83 (clean version) as Attachment PUC 3-3-3-C;

    4. TSA-NEP 83 (redlined version) as Attachment PUC 3-3-3-D;

    5. TSA-NEP-86 clean version) as Attachment PUC 3-3-3-E;

    6. Attachment B-1: TSA-NEP-86 (redlined version) as Attachment PUC 3-3-3-F;

    7. Letter Order accepting filing (addressing both Docket Nos. ER15-1466-000 and ER15-1466-001) as Attachment PUC 3-3-3-G.

Prepared by or under the supervision: Legal Department

<u>PUC 3-3, page 3</u>

- Documents related to Docket No. ER19-707-000 attached as Attachments PUC 3-3-4-A through D. This filing was intended to amend TSA-NEP-83 only.

    1. Transmittal Letter as Attachment PUC 3-3-4-A;
    2. TSA-NEP-83 (clean version) as Attachment PUC 3-3-4-B;
    3. TSA-NEP-83 (redlined version) as Attachment PUC 3-3-4-C;
    4. Letter Order accepting filing as Attachment PUC 3-3-4-D.

- Current Version of TSA-NEP-83 now in effect as Attachment PUC 3-3-5.[1]

- Current Version of TSA-NEP-86 now in effect as Attachment PUC 3-3-6.

[1] Attachment PUC 3-3-5 is the version of TSA-NEP-83 that reflects all amendments accepted by FERC and that currently is in effect. In the course, of preparing this response, National Grid identified the need for an administrative filing by ISO New England Inc. and National Grid to ensure that the version of TSA-NEP-83 posted on FERC's eTariff system reflects the most recent amendments accepted by FERC in Docket No. ER19-707. That administrative filing will not change the substance of TSA-NEP-83 currently in effect.

July 28, 2014

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

Re: New England Power Company
Docket No. ER14-____-000
Filing of Original Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86 Under ISO-NE OATT

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] New England Power Company d/b/a National Grid ("NEP") joined by ISO New England Inc. ("ISO-NE") (together, the "Filing Parties")[3] submit the following two Local Service Agreements ("LSAs"):

(1) the LSA among NEP, Block Island Power Company ("BIPCO"), and ISO New England Inc. ("ISO-NE"), designated as Original Service Agreement No. TSA-NEP-83 under the ISO-NE OATT; and

(2) the LSA among NEP, The Narragansett Electric Company ("Narragansett"), and ISO-NE, designated as Original Service Agreement No. TSA-NEP-86 under the ISO-NE OATT.

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1 16 U.S.C. § 824d.

2 18 C.F.R. Part 35.

3 NEP, and not ISO-NE, has the FPA section 205 rights over Schedule 21-NEP of the ISO-NE Open Access Transmission Tariff ("OATT"), pursuant to which NEP offers and administers Local Service. ISO-NE does not offer or administer Local Service and joins this filing solely to fulfill its obligations to file Local Service Agreements on the applicable Participating Transmission Owner ("PTO"), in accordance with Article 3.03(d)(ii) of the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs. *See ISO New England Inc.*, 124 FERC ¶ 61,297 (2008).

NEP believes the LSAs conform to the Form of Local Service Agreement contained in Attachment A to Schedule 21-Common of the ISO-NE OATT, and thus the LSAs do not need to be filed. Nevertheless, the Filing Parties are filing them out of an abundance of caution. ISO-NE, a party to each LSA and the entity responsible for filing with the Commission, or electronically reporting to the Commission, the LSAs,[4] raised a concern that the provisions in the LSAs regarding the Block Island Transmission System ("BITS") Surcharge may render the LSAs non-conforming. In circumstances like these, the Commission has directed that agreements should be filed with the Commission if there is any uncertainty as to the obligation to file such agreements.[5]

If the Commission determines that the LSAs need to be filed, the Filing Parties request that the Commission accept them effective 61 days after the date of this filing, *i.e.*, September 27, 2014. If, on the other hand, the Commission determines that the LSAs do not need to be filed, the Filing Parties will include them in the ISO-NE Electric Quarterly Reports with that same effective date.

I. Background

The LSAs were executed in order to include the Town of New Shoreham Project under the integrated facilities provisions of NEP's FERC Electric Tariff No. 1 ("Tariff No. 1").[6] The Town of New Shoreham Project is a public policy project authorized and directed by a Rhode Island statute of the same name.[7] The statute directs that:

> it is in the public interest for the state to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the [Rhode Island] mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health

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4 *See* Transmission Operating Agreement, Article 3.03(d)(ii).

5 *Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139, at 61,979 (1993).

6 Pursuant to those integrated facilities provisions, NEP supports the cost of the transmission facilities of its affiliate Narragansett, and Narragansett makes its transmission facilities available to be controlled and operated by NEP so that the transmission facilities of NEP and NEP's New England distribution affiliates are operated on an integrated basis and made available for open access transmission service in accordance with the ISO-NE OATT.

7 Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7 (Supp. 2010).

> impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland.[8]

The statute authorizes and sets forth a process for developing the Town of New Shoreham Project, an associated power purchase agreement, transmission arrangements, and recovery of related costs. It also permits Narragansett, at its option, to own, operate, or otherwise participate in the transmission cable project.[9]

The Deepwater Block Island Wind, LLC ("Block Island Wind") generation project, a 30-megawatt (nameplate) demonstration-scale offshore wind facility, is the offshore wind demonstration project described in the statute. Narragansett has agreed to construct, own, and operate the undersea cable between Block Island and the mainland and related facilities, which include a substation to be built on Block Island that will interconnect the Block Island Wind project to Narragansett's existing 34.5 kV system on the mainland. In addition, BIPCO, serving the Town of New Shoreham on Block Island, will interconnect to the same substation and will be electrically interconnected to the mainland for the first time by the same undersea cable. The cable will allow power to flow either from the Block Island Wind project to Block Island to the Rhode Island mainland, or from generators located on the mainland to Block Island, as needed. The Town of New Shoreham Project is currently estimated to be completed by late 2016.

On July 24, 2014, NEP filed a Large Generator Interconnection Agreement ("LGIA") with Block Island Wind in Docket No. ER14-2496-000, in order to interconnect the Block Island Wind project to Narragansett's system. In that filing, NEP also explained that it planned to (1) execute Original Service Agreement No. TSA-NEP-83 and (2) terminate its current Network Integration Transmission Service Agreement No. 108 with Narragansett and replace it with Original Service Agreement No. TSA-NEP-86.[10]

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8 *Id.*, § 39-26.1-7(a).

9 *Id.*, § 39-26.1-7(f). The statute specifies that "all costs incurred in the negotiation, administration, enforcement, transmission engineering associated with the design of the cable, and implementation of the project and agreement shall be recovered annually by the electric distribution company [*i.e.*, Narragansett] in electric distribution rates." *Id.*, § 39-26.1-7(d). The statute also directs that, should Narragansett own, operate, and maintain the cable, "the annual costs incurred by [Narragansett] directly or through transmission charges shall be recovered annually through a fully reconciling rate adjustment from customers of [Narragansett] and/or from the Block Island Power Company or its successor, subject to any federal approvals that may be required by law." *Id.*, § 39-26.1-7(f). Further, "[t]he revenue requirement for the annual cable costs shall be calculated in the same manner that the revenue requirement is calculated for other transmission facilities in Rhode Island for local network service under the jurisdiction of the federal energy regulatory commission." *Id.*

10 NEP will make a separate filing with the Commission to terminate Network Integration Transmission Service Agreement No. 108 with Narragansett.

II. The LSAs

ISO-NE raised a concern that the provisions in the LSAs regarding the BITS Surcharge may render the LSAs non-conforming, on the grounds that ISO-NE does not consider the BITS Surcharge to be a charge contemplated by Schedule 21-NEP of the ISO-NE OATT; but rather, a charge stemming from the Rhode Island statute referenced above. Those are the only provisions about which ISO-NE has such a concern, *i.e.*, all the parties to the LSAs agree that the other provisions are conforming.

The provisions on the BITS Surcharge are set forth in Part II, Section 2(p) and a referenced attachment in each LSA. Part II, Section 2(p) of each LSA states that "[s]ervice under this Local Service Agreement shall be subject to the following charges" and then lists the applicable charges, including the BITS Surcharge. By comparison, the Form of Local Service Agreement contained in Attachment A to Schedule 21-Common of the ISO-NE OATT includes the same sentence quoted above (*i.e.*, it states that service shall be subject to charges specified therein) but it does not list any charges. NEP believes that, because the Form of Local Service Agreement contemplates that additional applicable charges may be listed, the listing of such a charge in each of these LSAs does not render the LSAs nonconforming. Nevertheless, due to the concern raised by ISO-NE and out of an abundance of caution, the Filing Parties are filing the LSAs.

The provisions meet the requirements in the Rhode Island statute regarding the Town of New Shoreham Project which state that the annual costs incurred by Narragansett for the BITS facilities will be recovered annually from its customers and/or from BIPCO through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.[11] The BITS Surcharge will be calculated pursuant to a formula specified in the provisions.

III. Effective Date

If the Commission determines that the LSAs are non-conforming and therefore need to be filed, the Filing Parties request that the Commission accept them effective 61 days after the date of this filing, *i.e.*, September 27, 2014. If, however, the Commission determines that the LSAs do not need to be filed, the Filing Parties will include them in ISO-NE's Electric Quarterly Reports with that same effective date.

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[11] Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7(f).

IV. Attachments

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Executed Original Service Agreement No. TSA-NEP-83
Attachment A-1	Marked comparison between Service Agreement No. TSA-NEP-83 and the Form of Local Service Agreement set forth in Section 21-Common of the ISO-NE OATT
Attachment B	Executed Original Service Agreement No. TSA-NEP-86
Attachment B-1	Marked comparison between Service Agreement No. TSA-NEP-86 and the Form of Local Service Agreement set forth in Section 21-Common of the ISO-NE OATT

V. Description of the Filing Parties and Communications

NEP is a wholly owned subsidiary of National Grid USA. NEP is a public utility subject to the Commission's jurisdiction that owns transmission facilities located in New England. NEP's primary business is the transmission of electricity at wholesale to electric utilities and municipalities in New England. NEP operates transmission facilities that it owns directly as well as certain transmission facilities owned by its distribution affiliates in New England pursuant to integrated facilities agreements under Tariff No. 1. NEP acts as the transmission provider for itself and its New England distribution affiliates. NEP is a PTO under the terms of the TOA by and among the New England PTOs and ISO-NE. All of NEP's transmission facilities, including those owned by its New England distribution affiliates, are subject to the operating authority of ISO-NE under the terms of the TOA and are available for open access transmission service under the terms of Section II of the ISO-NE Tariff.

ISO-NE is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. ISO-NE operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the ISO-NE Transmission, Markets and Services Tariff and the Transmission Operating Agreement with the New England transmission owners. In its capacity as an RTO, ISO-NE also has the objective to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC").

Communications and correspondence regarding this filing should be addressed to the following individuals:

NEP:

Daniel Galaburda
Assistant General Counsel
and Director
National Grid USA
40 Sylvan Road
Waltham, MA 02451
(781) 907-2422
daniel.galaburda@nationalgrid.com

Kenneth G. Jaffe
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Washington, DC 20004
(202) 239-3300
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William Malee
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terry.schwennesen@nationalgrid.com

ISO-NE:

Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
(413) 535-4000
Fax: (413) 535-4379
mgonzalez@iso-ne.com

VI. Service

Copies of this filing have been served on Block Island Wind, Narragansett, BIPCO, and the Rhode Island Public Utilities Commission.

VII. Conclusion

For these reasons, if the Commission determines that the LSAs are non-conforming and therefore need to be filed, the Filing Parties request that the Commission accept them effective 61 days September 27, 2014. Please contact the undersigned with any questions regarding this filing.

Respectfully submitted,

/s/ Kenneth G. Jaffe
Kenneth G. Jaffe
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Terry Schwennesen
Counsel for National Grid
40 Sylvan Road
Waltham, MA 02451

Attorneys for National Grid USA

/s/ Monica Gonzalez
Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Attorney for ISO New England Inc.

Attachment A

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND, INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of May __, 2014 is entered into, by and between New England Power Company d/b/a/ National Grid , a corporation organized and existing under the laws of the State/Commonwealth of Massachusetts ("Transmission Owner"), Block Island Power Company , a corporation organized and existing under the laws of the State/Commonwealth of Rhode Island ("Transmission Customer") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

_X_ Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: Clifford R. McGinness
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

   a. Term of Service: See 2 above.

   b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
Initially up to 4.6 MW and 15TWh of Network Load

d. Description of Local Network Load:
Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
At the Transmission Owner's Affiliate's 34.5 kV substation on Block Island.
Note: The metering is on the 34.5 kV side and the Transmission Owner owns the meter.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:
1-34.5kV breaker, 1-34.5/4.16kV/2.4kV transformer, 5kV insulated line to customer substation and associated equipment.

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

At 34.5kV at the Transmission Owner's Affiliate's 34.5kV substation on Block Island.

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. Additional terms and conditions:

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room. Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5 kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable.

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time	
Milestone	Period For Completion
(Activity)	(# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: Albert Casazza President 5/19/2014
Name Title Date

Albert R. Casazza
Print Name

Transmission Owner:
By: William L. Malee Authorized Representative 5/14/14
Name Title Date

William L. Malee

The ISO:
By: Stephen J. Rourke V.P. System Planning 5/23/14
Name Title Date

Stephen J. Rourke
Print Name

Attachment 1

Block Island Transmission System (BITS) Surcharge

This Attachment 1 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Owner's Affiliate, The Narragansett Electric Company, and constructed to interconnect Transmission Customer and Deepwater Block Island Wind, LLC to the New England Transmission System in accordance with the Rhode Island General Laws, § 39-26.1-7, known as the Town of New Shoreham Project ("Project"). The intent of the Project is to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland. Provided that the Project goes forward as intended, the annual costs incurred by The Narragansett Electric Company ("TNECO") for the BITS facilities shall be recovered annually from its customers and from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, the provisions of which are set forth below, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KV switching station on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage shall be the lower of BIPCO's Annual Peak Load Ratio Share or its Energy Ratio Share from the prior calendar year. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Share shall be determined as a percentage according to the following formula:

   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Share:

Illustrative Example:

2010 Peak Load Results

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Results

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh
(4) BIPCO Energy Ratio Share ((1)/(3)) =	0.25803%

Transmission Customer's Share Percentage in this example would be 0.19508%.

Attachment A-1

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND, INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of May __, 2014 is entered into, by and between New England Power Company d/b/a/ National Grid , a corporation organized and existing under the laws of the State/Commonwealth of Massachusetts (“Transmission Owner”), Block Island Power Company , a corporation organized and existing under the laws of the State/Commonwealth of Rhode Island (“Transmission Customer”) and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware (“ISO”). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a “Party” or collectively as the “Parties.”

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

_X_ Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and

pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: Clifford R. McGinness
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal

Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

   a. Term of Service: See 2 above.

   b. List of Network Resources and Point(s) of Receipt:

   c. Description of capacity and energy to be transmitted:
      Initially up to 4.6 MW and 15TWh of Network Load

   d. Description of Local Network Load:
      Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:

At the Transmission Owner's Affiliate's 34.5 kV substation on Block Island.

Note: The metering is on the 34.5 kV side and the Transmission Owner owns the meter.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:

The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

1-34.5kV breaker, 1-34.5/4.16kV/2.4kV transformer, 5kV insulated line to customer substation and associated equipment.

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

At 34.5kV at the Transmission Owner's Affiliate's 34.5kV substation on Block Island.

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. Additional terms and conditions:

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room. Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5 kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable.

4. Planned work schedule.

Estimated Time

Milestone	Period For Completion
(Activity)	(# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) __________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________ .

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k. Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time	
Milestone	Period For Completion
(Activity)	(# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

(Added)ion Customer:

By: [signature] President 5/19/2014
Name Title Date

Albert R. Casazza
Print Name

Transmission Owner:
By: [signature] Authorized Representative 5/14/14
Name Title Date

William L. Malee

The ISO:
By: [signature] V.P. System Planning 5/23/14
Name Title Date

Stephen J. Rourke
Print Name

Attachment 1

Block Island Transmission System (BITS) Surcharge

This Attachment 1 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Owner's Affiliate, The Narragansett Electric Company, and constructed to interconnect Transmission Customer and Deepwater Block Island Wind, LLC to the New England Transmission System in accordance with the Rhode Island General Laws, § 39-26.1-7, known as the Town of New Shoreham Project ("Project"). The intent of the Project is to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland. Provided that the Project goes forward as intended, the annual costs incurred by The Narragansett Electric Company ("TNECO") for the BITS facilities shall be recovered annually from its customers and from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, the provisions of which are set forth below, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KV switching station on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage shall be the lower of BIPCO's Annual Peak Load Ratio Share or its Energy Ratio Share from the prior calendar year. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Share shall be determined as a percentage according to the following formula:

   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Share:

Illustrative Example:

2010 Peak Load Results

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Results

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) BIPCO Energy Ratio Share ((1)/(3)) = 0.25803%

Transmission Customer's Share Percentage in this example would be 0.19508%.

Attachment B

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

THE NARRAGANSETT ELECTRIC COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of May 31, 2014, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), The Narragansett Electric Companyd/b/a/ National Grid, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take

and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
The Narragansett Electric Company
Attn: President
280 Melrose Street
Providence, RI 02907

Transmission Owner:
New England Power Company
Attention: Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205

of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.
2. Service shall commence on the later of: (l) the date that termination becomes effective for the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997, by and between New England Power Company and The Narragansett Electric Company, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on or after the date that Contract Termination Charges, defined and set forth in the Stipulation and Agreement and the Amendment to the Service Agreement between the Transmission Customer and Transmission Owner under the Transmission Owner's FERC Electric Tariff, Original Volume 1 filed on May 30, 1997 in Docket No. ER97-680-000 and conditionally approved by the Commission on November 26, 1997(the "Restructuring Agreements"), are fully recovered from the Transmission Customer. Following that date, service under this Local Service Agreement shall continue until modified or terminated upon the written consent of the parties or upon five years advance written notice by any party to the others.

3. Specifications for Local Network Service.

a. Term of Service: See 2 above.

b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
1.8 GW and 7800 GWh

d. Description of Local Network Load:

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
See Attachment 1

f. List of non-Network Resource(s), to the extent known:
None

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer has executed a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

As of the execution date of this Local Service Agreement, the Schedule 21-NEP charges include a:

- Monthly demand charge with PTF and non-PTF components
- Transformer surcharge
- Meter surcharge
- Network load dispatch surcharge
- Third party support payments
- Direct Assignment Facility charge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 2)

q. Additional terms and conditions:

This Local Service Agreement amends and replaces the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997 and entered into by and between New England Power Company and The Narragansett Electric Company for the purpose of implementing wholesale competition or retail access for the Transmission Customer's retail customers pursuant to the Rhode Island Restructuring Act of 1996 ("URA"). Pursuant to the NITS Agreement, the following terms and conditions will remain in effect under the terms of this Local Service Agreement:

(i) In the event that Transmission Customer is denied recovery in its rates for local distribution service of access charges sufficient to collect the full amount of the Contract Termination Charges billed to Transmission Customer, its successors or assigns, by Transmission Owner, its successors or assigns, Transmission Owner, its successors or assigns, providing service over the transmission facilities covered by this Local Service Agreement shall collect the unrecovered balance of the Contract Termination Charges as a surcharge under this Local Service Agreement to the Transmission Customer or to any consumer taking delivery of electric energy over the transmission or distribution facilities of the Transmission Customer.

(ii) The obligations under this Local Service Agreement may be assigned only with the express written consent of the other parties, which consent shall not be unreasonably withheld, provided, however, that the Transmission Owner shall not be obligated to consent to any assignment that adversely affects the ability of the Transmission Owner to recover from the Transmission Customer the payments required to be made under the Tariff, and this Local Service Agreement, including any Contract Termination Charges that may be billed to Transmission Customer pursuant to the paragraph above.

(iii) The Transmission Owner has agreed to terminate those requirements of its FERC Electric Tariff, Original Volume No. 1 ("Tariff No. 1") that obligate the Transmission Customer to buy all of its electricity requirements under Tariff No. 1 and Transmission Customer has agreed to pay Contract Termination Charges pursuant to the Restructuring Agreements.

(iv) In no event shall the Transmission Owner bypass the Transmission Customer's distribution facilities and interconnect directly with a retail customer.

(v) To the extent ISO New England, Inc. or NEPOOL does not directly bill the Transmission Customer, any charges by ISO New England, Inc. or NEPOOL specifically incurred by the Transmission Owner, as a result of services provided to the Transmission Customer, will be directly assigned to the Transmission Customer as provided for under Section 24.6 of Schedule 21-NEP. The Transmission Owner will determine the direct charges to the Transmission Customer on the basis of the Transmission Customer's contribution to the incurrence of those charges using the same allocation methodology used by ISO New

England, Inc. or NEPOOL to allocate those costs to the Transmission Owner.

4. Planned work schedule.

Estimated Time

Milestone	Period For Completion
(Activity)	(# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service N/A

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By:____________________ President May 31, 2014
Name Title Date

Timothy F. Horan
Print Name

Transmission Owner:

By: William L Malee Authorized Representative May 31, 2014
Name Title Date

William L Malee
Print Name

The ISO:

By:____________________ V.P. System Planning 6/9/14
Name Title Date

Stephen J. Rourke
Print Name

Attachment 1

The Narragansett Electric Company

Points of Delivery

Main District
Admiral Street Substation
Blackburn Substation
Bristol Substation
Clarkson Street Substation
Davisville Substation
Drumrock Substation
EMI Tiverton Station Service
Farnum Pike Substation
FPL RISEP Station Service
Franklin Square Substation
Johnston Substation
Kent County Substation
Kenyon Substation
Kilvert Substation
Lincoln Ave. Substation
Mink Street Substation
Old Baptist Road Substation
Phillipsdale Substation
Point Street Substation
Pontiac Substation
Putnam Pike
Sockanosset Substation
South Street Station
Tiverton Substation
Tower Hill Substation
Wampanoag Substation
Warren Substation
West Cranston Substation
West Kingston Substation
Wolf Hill Substation
Wood River Substation
Woonsocket Substation

Blackstone Valley
Nasonville B23 Line from W. Farnum
West Farnum tap off 174
Farnum off H 17 Line
Riverside - R9/J16/H17
Pawtucket No. 1 Station X3/P11/T7
Staples J16/Q10
Vallev R9P11
Washington V148 from Robinson Ave
Ocean State Power Station Service

Newport
Canonicus St. M13L14

Metering Points (To the extent they differ from a Point of Delivery)

Main District
Pawtucket Power
Johnston Landfill
Valley Hydro
Cranston Landfill

Blackstone Valley
Roosevelt Hydro
Blackstone Hydro, Inc.
Blackstone Hydro Assoc.
Pawtucket #2 Hydro
Woonsocket Hydro

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated

annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO Load Ratio Share Percentage. The BIPCO Load Ratio Share Percentage shall be the lower of BIPCO's Annual Peak Load Ratio Share or its Energy Ratio Share from the prior calendar year. The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Share shall be determined as a percentage according the the following formula:

   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + Transmission Customer Annual kWh)

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Peak Load Results

(1) BIPCo Annual Peak Load =	3,604 kW
(2) Transmission Customer Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Results

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) Transmission Customer Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) BIPCO Energy Ratio Share ((1)/(3)) = 0.25803%

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

Attachment B-1

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

THE NARRAGANSETT ELECTRIC COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of May 31, 2014, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the ~~State/~~Commonwealth of Massachusetts (“Transmission Owner”), ______________________~~, a~~ The Narragansett Electric Companyd/b/a/ National Grid, a corporation organized and existing under the laws of the State~~/Commonwealth~~ of Rhode Island (“Transmission Customer”) and ISO New England~~,~~ Inc., a non-stock corporation organized and existing under the laws of the State of Delaware (“ISO”). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a “Party” or collectively as the “Parties.”

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and

pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
The Narragansett Electric Company
Attn: President
280 Melrose Street
Providence, RI 02907

Transmission Owner:
New England Power Company
Attention: Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal

Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) the date that termination becomes effective for the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997, by and between New England Power Company and The Narragansett Electric Company, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________~~.~~ or after the date that Contract Termination Charges, defined and set forth in the Stipulation and Agreement and the Amendment to the Service Agreement between the Transmission Customer and Transmission Owner under the Transmission Owner's FERC Electric Tariff, Original Volume 1 filed on May 30, 1997 in Docket No. ER97-680-000 and conditionally approved by the Commission on November 26, 1997(the "Restructuring Agreements"), are fully recovered from the Transmission Customer. Following that date, service under this Local Service Agreement shall continue until modified or terminated upon the written consent of the parties or upon five years advance written notice by any party to the others.

3. Specifications for Local Network Service.

a. Term of Service: See 2 above.

b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:

1.8 GW and 7800 GWh

d. Description of Local Network Load:

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:

See Attachment 1

f. List of non-Network Resource(s), to the extent known:

None

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:

The Transmission Customer has executed a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

As of the execution date of this Local Service Agreement, the Schedule 21-NEP charges include a:

- Monthly demand charge with PTF and non-PTF components
- Transformer surcharge
- Meter surcharge
- Network load dispatch surcharge
- Third party support payments
- Direct Assignment Facility charge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 2)

q. Additional terms and conditions:

This Local Service Agreement amends and replaces the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997 and entered into by and between New England Power Company and The Narragansett Electric Company for the purpose of implementing wholesale competition or retail access for the Transmission Customer's retail customers pursuant to the Rhode Island Restructuring Act of 1996 ("URA"). Pursuant to the NITS Agreement, the following terms and conditions will remain in effect under the terms of this Local Service Agreement:

(i) In the event that Transmission Customer is denied recovery in its rates for local distribution service of access charges sufficient to collect the full amount of the Contract Termination Charges billed to Transmission Customer, its successors or assigns, by Transmission Owner, its successors or assigns, Transmission Owner, its successors or assigns, providing service over the transmission facilities covered by this Local Service Agreement shall collect the unrecovered balance of the Contract Termination Charges as a surcharge under this Local Service Agreement to the Transmission Customer or to any consumer taking delivery of electric energy over the transmission or distribution facilities of the Transmission Customer.

(ii) The obligations under this Local Service Agreement may be assigned only with the express written consent of the other parties, which consent shall not be unreasonably withheld, provided, however, that the Transmission Owner shall not be obligated to consent to any assignment that adversely affects the ability of the Transmission Owner to recover from the Transmission Customer the payments required to be made under the Tariff, and this Local Service Agreement, including any Contract Termination Charges that may be billed to Transmission Customer pursuant to the paragraph above.

(iii) The Transmission Owner has agreed to terminate those requirements of its FERC Electric Tariff, Original Volume No. 1 ("Tariff No. 1") that obligate the Transmission Customer to buy all of its electricity requirements under Tariff No. 1 and Transmission Customer has agreed to pay Contract Termination Charges pursuant to the Restructuring Agreements.

(iv) In no event shall the Transmission Owner bypass the Transmission Customer's distribution facilities and interconnect directly with a retail customer.

(v) To the extent ISO New England, Inc. or NEPOOL does not directly bill the Transmission Customer, any charges by ISO New England, Inc. or NEPOOL specifically incurred by the Transmission Owner, as a result of services provided to the Transmission Customer, will be directly assigned to the Transmission Customer as provided for under Section 24.6 of Schedule 21-NEP. The Transmission Owner will determine the direct charges to the Transmission Customer on the basis of the Transmission Customer's contribution to the incurrence of those charges using the same allocation methodology used by ISO New England, Inc. or NEPOOL to allocate those costs to the Transmission Owner.

4. Planned work schedule.

Estimated Time	
Milestone	Period For Completion
(Activity)	(# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service N/A

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l)__________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ________________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k. Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone	Period For Completion
(Activity)	(# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

(Added graphics)

By:______________________ President May 31, 2014
Name Title Date

Timothy F. Horan
Print Name

Transmission Owner:

By:______________________ Authorized Representative May 31, 2014
Name Title Date

William L Malee
Print Name

The ISO:

By:______________________ V.P. System Planning 6/9/14
Name Title Date

Stephen J. Rourke
Print Name

Attachment 1

The Narragansett Electric Company

Points of Delivery

Main District
Admiral Street Substation
Blackburn Substation
Bristol Substation
Clarkson Street Substation
Davisville Substation
Drumrock Substation
EMI Tiverton Station Service
Farnum Pike Substation
FPL RISEP Station Service
Franklin Square Substation
Johnston Substation
Kent County Substation
Kenyon Substation
Kilvert Substation
Lincoln Ave. Substation
Mink Street Substation
Old Baptist Road Substation
Phillipsdale Substation
Point Street Substation
Pontiac Substation
Putnam Pike
Sockanosset Substation
South Street Station
Tiverton Substation
Tower Hill Substation
Wampanoag Substation
Warren Substation
West Cranston Substation
West Kingston Substation
Wolf Hill Substation
Wood River Substation
Woonsocket Substation

Blackstone Valley
Nasonville B23 Line from W. Farnum
West Farnum tap off 174
Farnum off H 17 Line
Riverside - R9/J16/H17
Pawtucket No. 1 Station X3/P11/T7
Staples J16/Q10
Vallev R9P11
Washington V148 from Robinson Ave
Ocean State Power Station Service

Newport
Canonicus St. M13L14

Attachment 1

Metering Points (To the extent they differ from a Point of Delivery)

Main District
Pawtucket Power
Johnston Landfill
Valley Hydro
Cranston Landfill

Blackstone Valley
Roosevelt Hydro
Blackstone Hydro, Inc.
Blackstone Hydro Assoc.
Pawtucket #2 Hydro
Woonsocket Hydro

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO Load Ratio Share Percentage. The BIPCO Load Ratio Share Percentage shall be the lower of BIPCO's Annual Peak Load Ratio Share or its Energy Ratio Share from the prior calendar year. The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Share shall be determined as a percentage according the the following formula:

   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + Transmission Customer Annual kWh)

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Peak Load Results

(1) BIPCo Annual Peak Load =	3,604 kW
(2) Transmission Customer Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Results

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) Transmission Customer Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) BIPCO Energy Ratio Share ((1)/(3)) = 0.25803%

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

ER14-2514 Deepwater Wind doc-less motion to intervene.TXT

Submission Description: (doc-less) Motion to Intervene of Deepwater Block Island Wind, LLC under ER14-2514-000.

Submission Date: 7/30/2014 11:06:41 AM

Filed Date: 7/30/2014 11:06:41 AM

Dockets

ER14-2514-000 ISO New England Inc. submits tariff filing per 35.13(a)(2)(iii): Local Service Agreements TSA-NEP-83 and TSA-NEP-86 submitted on 7/28/2014 1:27:23 PM, Filing Type code: 10

Filing Party/Contacts:

Filing Party	Signer (Representative)	Other Contact (Principal)
------------	-----------------------	-------------------------
Deepwater Block Island Wind, LLC	jcf@vnf.com	dschwartz@dwwind.com

Basis for Intervening:

Deepwater Wind Block Island Wind, LLC (Block Island Wind) is developing a 30 megawatt (nameplate) demonstration-scale offshore wind facility that will be located approximately three miles southeast of Block Island, Rhode Island (Block Island Wind Farm). The Local Service Agreements filed in this docket relate to the transmission facilities that will be constructed to facilitate development of the Block Island Wind Farm. Therefore, Block Island Wind has a substantial and direct interest in the outcome of this proceeding that cannot be adequately represented by any other party. Because Block Island Wind’s development plans may be directly affected by any determinations made in this proceeding, its participation as a party in this docket is appropriate and in the public interest.

BCR **Benjamin C. Riggs, Jr.**

July 30, 2014

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
Washington, D.C.
By e-mail

Re: Comment on Letter of ISO New England re New England Power Company dated July 28, 2014 (docket number not yet assigned)

Dear Secretary Bose:

Please accept this letter as my comment on the above referenced letter. The first page of that letter is attached to facilitate identification.

I filed a Complaint with respect to the Power Purchase Agreement between National Grid and Deepwater Wind Block Island that relates directly to this current matter back in 2012 under your docket no. EL-100-000. The FERC ultimately chose to take no action, and advised me of my option to bring the matter to a court of competent jurisdiction. Because this project has still not obtained its final permit approval (from the U.S. Army Corps of Engineers), and a legal challenge to its permit approval by the Coastal Resources Management Council is pending, no action has been taken to date by any party to file the appropriate suit in the U.S. District Court.

The objections raised in my FERC complaint relate to violation on the Commerce Clause and Supremacy Clause of the U.S. Constitution. Because these matters have not been adjudicated, it would be inappropriate for ISO New England to avoid formally filing their Local Service Agreements with the Commission. This matter should be subject to comments and objections by interested parties.

I have on this date served a courtesy copy of the same on the Service List provided in the referenced letter, by e-mail.

Benj C. Riggs, Jr.
Benjamin C. Riggs, Jr.

Attachment (1)

15-D Harrington Street, Newport, RI 02840
Tel. 401/846-2540 Fax. 846-1032
rmcriggs@earthlink.net

ISO new england

July 28, 2014

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

Re: New England Power Company
Docket No. ER14-____-000
Filing of Original Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86 Under ISO-NE OATT

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] New England Power Company d/b/a National Grid ("NEP") joined by ISO New England Inc. ("ISO-NE") (together, the "Filing Parties")[3] submit the following two Local Service Agreements ("LSAs"):

(1) the LSA among NEP, Block Island Power Company ("BIPCO"), and ISO New England Inc. ("ISO-NE"), designated as Original Service Agreement No. TSA-NEP-83 under the ISO-NE OATT; and

(2) the LSA among NEP, The Narragansett Electric Company ("Narragansett"), and ISO-NE, designated as Original Service Agreement No. TSA-NEP-86 under the ISO-NE OATT.

---

1 16 U.S.C. § 824d.

2 18 C.F.R. Part 35.

3 NEP, and not ISO-NE, has the FPA section 205 rights over Schedule 21-NEP of the ISO-NE Open Access Transmission Tariff ("OATT"), pursuant to which NEP offers and administers Local Service. ISO-NE does not offer or administer Local Service and joins this filing solely to fulfill its obligations to file Local Service Agreements on the applicable Participating Transmission Owner ("PTO"), in accordance with Article 3.03(d)(ii) of the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs. *See ISO New England Inc.*, 124 FERC ¶ 61,297 (2008).

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

New England Power Company and
ISO New England Inc.
Docket No. ER14-2514-000

Issued: 9/2/14

Alston & Bird LLP
950 F Street, NW
Washington, DC 20004

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Attention: Kenneth G. Jaffe
Attorney for National Grid USA

Monica Gonzalez
Senior Regulatory Counsel for ISO New England Inc.

Reference: Local Service Agreements

Dear Mr. Jaffe and Ms. Gonzalez:

On July 28, 2014, National Grid USA submitted, on behalf of New England Power Company (NEP) and ISO New England Inc. (ISO-NE), two nonconforming local service agreements (LSAs): (1) the LSA among NEP, Block Island Power Company (BIPCO), and ISO-NE;[1] and (2) the LSA among NEP, The Narragansett Electric Company (Narragansett), and ISO-NE.[2] You state the LSAs were filed to address ISO-NE's concern that the Block Island Transmission System Surcharge would render the LSAs

[1] ISO New England Inc., ISO New England Inc. Agreements and Contracts, Block Island LSA, LSA - TSA-NEP-83 NEP, Block Island Power and ISO-NE, 0.0.0.

[2] ISO New England Inc., ISO New England Inc. Agreements and Contracts, Narragansett LSA, LSA - TSA-NEP-86 NEP, Narragansett and ISO-NE, 0.0.0.

non-conforming.

Pursuant to the authority delegated to the Director, Division of Electric Power Regulation – East, under 18 C.F.R. §375.307, your submittal is accepted for filing, effective September 27, 2014, as requested.

The filing was noticed on July 28, 2014, with comments, interventions, and protests due on or before August 18, 2014. No adverse comments, interventions or protests were filed. Pursuant to Rule 214 (18 C.F.R. § 385.214 (2014)), to the extent that any timely filed motions to intervene and any motion to intervene out-of-time were filed before the issuance date of this order, such interventions are granted. Granting late interventions at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties.

This acceptance for filing shall not be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in your filing; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against NEP or ISO-NE.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Jignasa Gadani, Director
Division of Electric Power
Regulation – East

April 7, 2015

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

Re: New England Power Company
Docket No. ER15-____-000
Filing of First Revised Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86 Under ISO-NE OATT

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] New England Power Company d/b/a National Grid ("NEP") joined by ISO New England Inc. ("ISO-NE") (together, the "Filing Parties")[3] submit amendments to the following two Local Service Agreements ("LSAs"):

(1) the LSA among NEP, Block Island Power Company ("BIPCO"), and ISO New England Inc. ("ISO-NE"), designated as First Revised Service Agreement No. TSA-NEP-83 under the ISO-NE OATT; and

(2) the LSA among NEP, The Narragansett Electric Company ("Narragansett"), and ISO-NE, designated as First Revised Service Agreement No. TSA-NEP-86 under the ISO-NE OATT.

---

1 16 U.S.C. § 824d.

2 18 C.F.R. Part 35.

3 NEP, and not ISO-NE, has the FPA section 205 rights over Schedule 21-NEP of the ISO-NE Open Access Transmission Tariff ("OATT"), pursuant to which NEP offers and administers Local Service. ISO-NE does not offer or administer Local Service and joins this filing solely to fulfill its obligations to file Local Service Agreements on the applicable Participating Transmission Owner ("PTO"), in accordance with Article 3.03(d)(ii) of the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs. *See ISO New England Inc.*, 124 FERC ¶ 61,297 (2008).

The Filing Parties request that the Commission accept the LSAs effective 61 days after the date of this filing, *i.e.*, June 7, 2015

I. Background

The original LSAs were accepted by the Commission on September 2, 2014, by delegated letter order in Docket No. ER14-2514-000. The LSAs were executed in order to include the Town of New Shoreham Project under the integrated facilities provisions of NEP's FERC Electric Tariff No. 1 ("Tariff No. 1").[4] The Town of New Shoreham Project is a public policy project authorized and directed by a Rhode Island statute of the same name.[5] The statute directs that:

> it is in the public interest for the state to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the [Rhode Island] mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland.[6]

The statute authorizes and sets forth a process for developing the Town of New Shoreham Project, an associated power purchase agreement, transmission arrangements, and recovery of related costs. It also permits Narragansett, at its option, to own, operate, or otherwise participate in the transmission cable project.[7]

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[4] Pursuant to those integrated facilities provisions, NEP supports the cost of the transmission facilities of its affiliate Narragansett, and Narragansett makes its transmission facilities available to be controlled and operated by NEP so that the transmission facilities of NEP and NEP's New England distribution affiliates are operated on an integrated basis and made available for open access transmission service in accordance with the ISO-NE OATT.

[5] Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7 (Supp. 2010).

[6] *Id.*, § 39-26.1-7(a).

[7] *Id.*, § 39-26.1-7(f). The statute specifies that "all costs incurred in the negotiation, administration, enforcement, transmission engineering associated with the design of the cable, and implementation of the project and agreement shall be recovered annually by the electric distribution company [*i.e.*, Narragansett] in electric distribution rates." *Id.*, § 39-26.1-7(d). The statute also directs that, should Narragansett own, operate, and maintain the cable, "the annual costs incurred by [Narragansett] directly or through transmission charges shall be recovered annually through a fully reconciling rate adjustment from customers of [Narragansett] and/or from the Block Island Power Company or its successor, subject to any federal approvals that may be required by law." *Id.*, § 39-26.1-7(f). Further, "[t]he revenue requirement for the annual cable costs shall be calculated in the same manner that the revenue requirement is calculated

The Deepwater Block Island Wind, LLC ("Block Island Wind") generation project, a 30-megawatt (nameplate) demonstration-scale offshore wind facility, is the offshore wind demonstration project described in the statute. Narragansett has agreed to construct, own, and operate the undersea cable between Block Island and the mainland and related facilities, which include a substation to be built on Block Island that will interconnect the Block Island Wind project to Narragansett's existing 34.5 kV system on the mainland. In addition, BIPCO, serving the Town of New Shoreham on Block Island, will interconnect to the same substation and will be electrically interconnected to the mainland for the first time by the same undersea cable. The cable will allow power to flow either from the Block Island Wind project to Block Island to the Rhode Island mainland, or from generators located on the mainland to Block Island, as needed. The Town of New Shoreham Project is currently estimated to be completed by late 2016.

As part of the package of Agreements necessary to implement the transaction and interconnect Block Island Wind to the mainland, NEP also filed, (1) a Large Generator Interconnection Agreement ("LGIA") with Block Island Wind which was accepted by the Commission by delegated letter order on September 2, 2014, in Docket No. ER14-2496-000 and (2) an amendment to Service Agreement No. 23 under NEP's Tariff No. 1 accepted by the Commission by delegated letter order on September 2, 2014, in Docket No. ER14-2493-000. NEP also terminated its previous Network Integration Transmission Service Agreement No. 108 with Narragansett which was part of the record in Docket No. ER14-2519.

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for other transmission facilities in Rhode Island for local network service under the jurisdiction of the federal energy regulatory commission." *Id.*

II. The LSAs

The LSAs being filed in this proceeding have been revised to address a concern raised by the Rhode Island Division of Public Utilities and Carriers ("Division") that the Block Island Transmission System ("BITS") Surcharge[8] calculated under the LSAs did not fully conform with the Rhode Island statute referenced above. Specifically, the Division was concerned that the calculation of the BIPCO Share Percentage did not fully comport with the Rhode Island General Law Section 39-26.7(f) which states:

> "The allocation of the costs related to the transmission cable through transmission rates or otherwise shall be structured so that the estimated impact on the typical residential customer bill for such transmission costs for customers in the Town of New Shoreham *shall be higher* than the estimated impact on the typical residential customer bill for customers on the mainland of the electric distribution company." (Emphasis added)

To address the issues raised by the Division, NEP modified the BITS Surcharge by introducing a collar to the calculation of the BIPCO Share Percentage such that the impact on the typical residential customer in the Town of New Shoreham cannot be lower than 120% of the impact on the typical residential customer of The Narragansett Electric Company. All parties have executed these First Revised LSAs to reflect that change. NEP is authorized to state the Division also supports this modification.

III. Effective Date

The Filing Parties request that the Commission accept the LSAs effective 61 days after the date of this filing, *i.e.*, June 7, 2015.

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[8] *See* the BITS Surcharge provisions set forth in Part II, Section 2(p) of the LSAs and a referenced attachment in each LSA.

IV. Attachments

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Executed First Revised Service Agreement No. TSA-NEP-83;
Attachment A-1	Marked comparison between First Revised Service Agreement No. TSA-NEP-83 and Original Local Service Agreement No. TSA-NEP-83.
Attachment B	Executed First Revised Service Agreement No. TSA-NEP-86; and
Attachment B-1	Marked comparison between First Revised Service Agreement No. TSA-NEP-86 and Original Service Agreement No. TSA-NEP-86.

V. Description of the Filing Parties and Communications

NEP is a wholly owned subsidiary of National Grid USA. NEP is a public utility subject to the Commission's jurisdiction that owns transmission facilities located in New England. NEP's primary business is the transmission of electricity at wholesale to electric utilities and municipalities in New England. NEP operates transmission facilities that it owns directly as well as certain transmission facilities owned by its distribution affiliates in New England pursuant to integrated facilities agreements under Tariff No. 1. NEP acts as the transmission provider for itself and its New England distribution affiliates. NEP is a PTO under the terms of the TOA by and among the New England PTOs and ISO-NE. All of NEP's transmission facilities, including those owned by its New England distribution affiliates, are subject to the operating authority of ISO-NE under the terms of the TOA and are available for open access transmission service under the terms of Section II of the ISO-NE Tariff.

ISO-NE is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. ISO-NE operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the ISO-NE Transmission, Markets and Services Tariff and the Transmission Operating Agreement with the New England transmission owners. In its capacity as an RTO, ISO-NE also has the objective to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC").

Communications and correspondence regarding this filing should be addressed to the following individuals:

NEP:

Daniel Galaburda
Assistant General Counsel
and Director
National Grid USA
Service Company, Inc.
40 Sylvan Road
Waltham, MA 02451
(781) 907-2422
daniel.galaburda@nationalgrid.com

Kenneth G. Jaffe
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004
(202) 239-3300
kenneth.jaffe@alston.com
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William L. Malee
Director of Transmission
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Amanda C. Downey
Counsel
National Grid USA
Service Company, Inc.
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Waltham, MA 02451
(781) 907-2136
amanda.downey@nationalgrid.com

ISO-NE:

Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
(413) 535-4000
Fax: (413) 535-4379
mgonzalez@iso-ne.com

VI. Service

Copies of this filing have been served on Block Island Wind, Narragansett, BIPCO, the Rhode Island Division of Public Utilities and Carriers, and the Rhode Island Public Utilities Commission.

VII. Conclusion

For these reasons, the Filing Parties request that the Commission accept them effective 61 days from the date of filing, *i.e.*, June 7, 2015. Please contact the undersigned with any questions regarding this filing.

Respectfully submitted,

/s/ Kenneth G. Jaffe
Kenneth G. Jaffe
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Amanda C. Downey
Counsel
National Grid USA
Service Company, Inc.
40 Sylvan Road
Waltham, MA 02451

Attorneys for New England Power Company d/b/a National Grid

/s/ Monica Gonzalez
Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Attorney for ISO New England Inc.

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21
ATTACHMENT A
FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), Block Island Power Company, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

  __ Firm

  __ Non-Firm

  Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: Clifford R. McGinness
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

   a. Term of Service: See 2 above.

   b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
Initially up to 4.6 MW and 15TWh of Network Load

d. Description of Local Network Load:
Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
At the Transmission Owner's Affiliate's 34.5 kV substation on Block Island.
Note: The metering is on the 34.5 kV side and the Transmission Owner owns the meter.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:
1-34.5kV breaker, 1-34.5/4.16kV/2.4kV transformer, 5kV insulated line to customer substation and associated equipment.

j. Project name:

k. Interconnecting Transmission Customer:

l. **Location:**

m. **Transformer nameplate rating:**

n. **Interconnection point:**

At 34.5kV at the Transmission Owner's Affiliate's 34.5kV substation on Block Island.

o. **Additional facilities and/or associated equipment:**

p. **Service under this Local Service Agreement shall be subject to the following charges:**

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. **Additional terms and conditions:**

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room. Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5 kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: C.R. McGinnes V President + COO 1/22/15
Name Title Date

C.R. McGINNES
Print Name

Transmission Owner:

By: William L Malee Authorized Representative 1/8/15
Name Title Date

William L Malee
Print Name

The ISO:

By: V.P. System Planning 1/30/15
Name Title Date

Print Name

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Collar:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), Block Island Power Company, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: Clifford R. McGinness
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

   a. Term of Service: See 2 above.

   b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
Initially up to 4.6 MW and 15TWh of Network Load

d. Description of Local Network Load:
Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
At the Transmission Owner's Affiliate's 34.5 kV substation on Block Island.
Note: The metering is on the 34.5 kV side and the Transmission Owner owns the meter.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:
1-34.5kV breaker, 1-34.5/4.16kV/2.4kV transformer, 5kV insulated line to customer substation and associated equipment.

j. Project name:

k. Interconnecting Transmission Customer:

l. **Location:**

m. **Transformer nameplate rating:**

n. **Interconnection point:**

At 34.5kV at the Transmission Owner's Affiliate's 34.5kV substation on Block Island.

o. **Additional facilities and/or associated equipment:**

p. **Service under this Local Service Agreement shall be subject to the following charges:**

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. **Additional terms and conditions:**

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room. Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5 kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: C.R. McGinnes VPresident + COO 1/22/15
Name Title Date

C.R. McGinnes
Print Name

Transmission Owner:

By: Will L Malee Authorized Representative 1/8/15
Name Title Date

William L Malee
Print Name

The ISO:

By: V.P. System Planning 1/30/15
Name Title Date

Print Name

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Collar:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

ATTACHMENT A-1

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be ~~the lower of~~ BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share ~~or its Energy Ratio Share from the prior calendar year~~. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio ~~Share~~ Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio ~~Share~~Collar:

Illustrative Example:

2010 Annual Peak Load ~~Results~~

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy ~~Results~~Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

THE NARRAGANSETT ELECTRIC COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), The Narragansett Electric Company d/b/a/ National Grid, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take

and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
The Narragansett Electric Company
Attn: Mary K. Smith
280 Melrose Street
Providence, RI 02907

Transmission Owner:
New England Power Company
Attention: Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205

of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.
2. Service shall commence on the later of: (l) the date that termination becomes effective for the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997, by and between New England Power Company and The Narragansett Electric Company, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on or after the date that Contract Termination Charges, defined and set forth in the Stipulation and Agreement and the Amendment to the Service Agreement between the Transmission Customer and Transmission Owner under the Transmission Owner's FERC Electric Tariff, Original Volume 1 filed on May 30, 1997 in Docket No. ER97-680-000 and conditionally approved by the Commission on November 26, 1997(the "Restructuring Agreements"), are fully recovered from the Transmission Customer. Following that date, service under this Local Service Agreement shall continue until modified or terminated upon the written consent of the parties or upon five years advance written notice by any party to the others.

3. Specifications for Local Network Service.

a. Term of Service: See 2 above.

b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
1.8 GW and 7800 GWh

d. Description of Local Network Load:

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
See Attachment 1

f. List of non-Network Resource(s), to the extent known:
None

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer has executed a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

As of the execution date of this Local Service Agreement, the Schedule 21-NEP charges include a:

- Monthly demand charge with PTF and non-PTF components
- Transformer surcharge
- Meter surcharge
- Network load dispatch surcharge
- Third party support payments
- Direct Assignment Facility charge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 2)

q. Additional terms and conditions:

This Local Service Agreement amends and replaces the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997 and entered into by and between New England Power Company and The Narragansett Electric Company for the purpose of implementing wholesale competition or retail access for the Transmission Customer's retail customers pursuant to the Rhode Island Restructuring Act of 1996 ("URA"). Pursuant to the NITS Agreement, the following terms and conditions will remain in effect under the terms of this Local Service Agreement:

(i) In the event that Transmission Customer is denied recovery in its rates for local distribution service of access charges sufficient to collect the full amount of the Contract Termination Charges billed to Transmission Customer, its successors or assigns, by Transmission Owner, its successors or assigns, Transmission Owner, its successors or assigns, providing service over the transmission facilities covered by this Local Service Agreement shall collect the unrecovered balance of the Contract Termination Charges as a surcharge under this Local Service Agreement to the Transmission Customer or to any consumer taking delivery of electric energy over the transmission or distribution facilities of the Transmission Customer.

(ii) The obligations under this Local Service Agreement may be assigned only with the express written consent of the other parties, which consent shall not be unreasonably withheld, provided, however, that the Transmission Owner shall not be obligated to consent to any assignment that adversely affects the ability of the Transmission Owner to recover from the Transmission Customer the payments required to be made under the Tariff, and this Local Service Agreement, including any Contract Termination Charges that may be billed to Transmission Customer pursuant to the paragraph above.

(iii)The Transmission Owner has agreed to terminate those requirements of its FERC Electric Tariff, Original Volume No. 1 ("Tariff No. 1") that obligate the Transmission Customer to buy all of its electricity requirements under Tariff No. 1 and Transmission Customer has agreed to pay Contract Termination Charges pursuant to the Restructuring Agreements.

(iv)In no event shall the Transmission Owner bypass the Transmission Customer's distribution facilities and interconnect directly with a retail customer.

(v) To the extent ISO New England, Inc. or NEPOOL does not directly bill the Transmission Customer, any charges by ISO New England, Inc. or NEPOOL specifically incurred by the Transmission Owner, as a result of services provided to the Transmission Customer, will be directly assigned to the Transmission Customer as provided for under Section 24.6 of Schedule 21-NEP. The Transmission Owner will determine the direct charges to the Transmission Customer on the basis of the Transmission Customer's contribution to the incurrence of those charges using the same allocation methodology used by ISO New

England, Inc. or NEPOOL to allocate those costs to the Transmission Owner.

4. Planned work schedule.

Estimated Time

Milestone	Period For Completion
(Activity)	(# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service N/A

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) _________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ___________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone	Period For Completion
(Activity)	(# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: [signature]	President	1/12/15
Name	Title	Date

Timothy F. Horan
Print Name

Transmission Owner:

By: William L Malee	Authorized Representative	1/12/15
Name	Title	Date

William L Malee
Print Name

The ISO:

By: [signature]	V.P. System Planning	1/21/15
Name	Title	Date

Stephen J. Rourke
Print Name

Attachment 1

The Narragansett Electric Company

Points of Delivery

Main District
Admiral Street Substation
Blackburn Substation
Bristol Substation
Clarkson Street Substation
Davisville Substation
Drumrock Substation
EMI Tiverton Station Service
Farnum Pike Substation
FPL RISEP Station Service
Franklin Square Substation
Johnston Substation
Kent County Substation
Kenyon Substation
Kilvert Substation
Lincoln Ave. Substation
Mink Street Substation
Old Baptist Road Substation
Phillipsdale Substation
Point Street Substation
Pontiac Substation
Putnam Pike
Sockanosset Substation
South Street Station
Tiverton Substation
Tower Hill Substation
Wampanoag Substation
Warren Substation
West Cranston Substation
West Kingston Substation
Wolf Hill Substation
Wood River Substation
Woonsocket Substation

Blackstone Valley
Nasonville B23 Line from W. Farnum
West Farnum tap off 174
Farnum off H 17 Line
Riverside - R9/J16/H17
Pawtucket No. 1 Station X3/P11/T7
Staples J16/Q10
Vallev R9P11
Washington V148 from Robinson Ave
Ocean State Power Station Service

Newport
Canonicus St. M13L14

Attachment 1

Metering Points (To the extent they differ from a Point of Delivery)

Main District
Pawtucket Power
Johnston Landfill
Valley Hydro
Cranston Landfill

Blackstone Valley
Roosevelt Hydro
Blackstone Hydro, Inc.
Blackstone Hydro Assoc.
Pawtucket #2 Hydro
Woonsocket Hydro

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO Share Percentage. The BIPCO Share Percentage shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar year as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy = 13,369,466 kWh

(2) TNECO Annual Energy =	<u>7,751,887,000 kWh</u>
(3) Total Annual Energy	7,765,256,466 kWh
(4) Minimum Energy Ratio Share ((1)/(3)) =	0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	<u>7,751,887,000 kWh</u>
(3) Total Annual Energy	7,771,941,199 kWh
(4) Maximum Energy Ratio Share ((1)/(3)) =	0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, the BIPCO Share Percentage in this example would be 0.19508%.

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

THE NARRAGANSETT ELECTRIC COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), The Narragansett Electric Company d/b/a/ National Grid, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take

and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
The Narragansett Electric Company
Attn: Mary K. Smith
280 Melrose Street
Providence, RI 02907

Transmission Owner:
New England Power Company
Attention: Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205

of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.
2. Service shall commence on the later of: (l) the date that termination becomes effective for the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997, by and between New England Power Company and The Narragansett Electric Company, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on or after the date that Contract Termination Charges, defined and set forth in the Stipulation and Agreement and the Amendment to the Service Agreement between the Transmission Customer and Transmission Owner under the Transmission Owner's FERC Electric Tariff, Original Volume 1 filed on May 30, 1997 in Docket No. ER97-680-000 and conditionally approved by the Commission on November 26, 1997(the "Restructuring Agreements"), are fully recovered from the Transmission Customer. Following that date, service under this Local Service Agreement shall continue until modified or terminated upon the written consent of the parties or upon five years advance written notice by any party to the others.

3. Specifications for Local Network Service.

a. Term of Service: See 2 above.

b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
1.8 GW and 7800 GWh

d. Description of Local Network Load:

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
See Attachment 1

f. List of non-Network Resource(s), to the extent known:
None

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer has executed a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

As of the execution date of this Local Service Agreement, the Schedule 21-NEP charges include a:

- Monthly demand charge with PTF and non-PTF components
- Transformer surcharge
- Meter surcharge
- Network load dispatch surcharge
- Third party support payments
- Direct Assignment Facility charge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 2)

q. Additional terms and conditions:

This Local Service Agreement amends and replaces the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997 and entered into by and between New England Power Company and The Narragansett Electric Company for the purpose of implementing wholesale competition or retail access for the Transmission Customer's retail customers pursuant to the Rhode Island Restructuring Act of 1996 ("URA"). Pursuant to the NITS Agreement, the following terms and conditions will remain in effect under the terms of this Local Service Agreement:

(i) In the event that Transmission Customer is denied recovery in its rates for local distribution service of access charges sufficient to collect the full amount of the Contract Termination Charges billed to Transmission Customer, its successors or assigns, by Transmission Owner, its successors or assigns, Transmission Owner, its successors or assigns, providing service over the transmission facilities covered by this Local Service Agreement shall collect the unrecovered balance of the Contract Termination Charges as a surcharge under this Local Service Agreement to the Transmission Customer or to any consumer taking delivery of electric energy over the transmission or distribution facilities of the Transmission Customer.

(ii) The obligations under this Local Service Agreement may be assigned only with the express written consent of the other parties, which consent shall not be unreasonably withheld, provided, however, that the Transmission Owner shall not be obligated to consent to any assignment that adversely affects the ability of the Transmission Owner to recover from the Transmission Customer the payments required to be made under the Tariff, and this Local Service Agreement, including any Contract Termination Charges that may be billed to Transmission Customer pursuant to the paragraph above.

(iii) The Transmission Owner has agreed to terminate those requirements of its FERC Electric Tariff, Original Volume No. 1 ("Tariff No. 1") that obligate the Transmission Customer to buy all of its electricity requirements under Tariff No. 1 and Transmission Customer has agreed to pay Contract Termination Charges pursuant to the Restructuring Agreements.

(iv) In no event shall the Transmission Owner bypass the Transmission Customer's distribution facilities and interconnect directly with a retail customer.

(v) To the extent ISO New England, Inc. or NEPOOL does not directly bill the Transmission Customer, any charges by ISO New England, Inc. or NEPOOL specifically incurred by the Transmission Owner, as a result of services provided to the Transmission Customer, will be directly assigned to the Transmission Customer as provided for under Section 24.6 of Schedule 21-NEP. The Transmission Owner will determine the direct charges to the Transmission Customer on the basis of the Transmission Customer's contribution to the incurrence of those charges using the same allocation methodology used by ISO New

England, Inc. or NEPOOL to allocate those costs to the Transmission Owner.

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service N/A

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) _________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ___________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone	Period For Completion
(Activity)	(# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: ______________ President 1/12/15
Name Title Date

Timothy F. Horan
Print Name

Transmission Owner:

By: William L Malee Authorized Representative 1/12/15
Name Title Date

William L Malee
Print Name

The ISO:

By: ______________ V.P. System Planning 1/21/15
Name Title Date

Stephen J. Rourke
Print Name

Attachment 1

The Narragansett Electric Company

Points of Delivery

Main District
Admiral Street Substation
Blackburn Substation
Bristol Substation
Clarkson Street Substation
Davisville Substation
Drumrock Substation
EMI Tiverton Station Service
Farnum Pike Substation
FPL RISEP Station Service
Franklin Square Substation
Johnston Substation
Kent County Substation
Kenyon Substation
Kilvert Substation
Lincoln Ave. Substation
Mink Street Substation
Old Baptist Road Substation
Phillipsdale Substation
Point Street Substation
Pontiac Substation
Putnam Pike
Sockanosset Substation
South Street Station
Tiverton Substation
Tower Hill Substation
Wampanoag Substation
Warren Substation
West Cranston Substation
West Kingston Substation
Wolf Hill Substation
Wood River Substation
Woonsocket Substation

Blackstone Valley
Nasonville B23 Line from W. Farnum
West Farnum tap off 174
Farnum off H 17 Line
Riverside - R9/J16/H17
Pawtucket No. 1 Station X3/P11/T7
Staples J16/Q10
Vallev R9P11
Washington V148 from Robinson Ave
Ocean State Power Station Service

Newport
Canonicus St. M13L14

Attachment 1

Metering Points (To the extent they differ from a Point of Delivery)

Main District
Pawtucket Power
Johnston Landfill
Valley Hydro
Cranston Landfill

Blackstone Valley
Roosevelt Hydro
Blackstone Hydro, Inc.
Blackstone Hydro Assoc.
Pawtucket #2 Hydro
Woonsocket Hydro

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO Share Percentage. The BIPCO Share Percentage shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar year as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

<u>2010 Annual Peak Load</u>

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

<u>2010 Energy Ratio Collar</u>

(1) 1.2* BIPCO Annual Energy = 13,369,466 kWh

(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh
(4) Minimum Energy Ratio Share ((1)/(3)) =	0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh
(4) Maximum Energy Ratio Share ((1)/(3)) =	0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, the BIPCO Share Percentage in this example would be 0.19508%.

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

ATTACHMENT B-1

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO ~~Load Ratio~~ Share Percentage. The BIPCO ~~Load Ratio~~ Share Percentage shall be ~~the lower of~~ BIPCO's Annual Peak Load Ratio Share from the prior calendar year as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. ~~or its Energy Ratio Share from the prior calendar year.~~ The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

~~4. BIPCO's Energy Ratio Share shall be determined as a percentage according the the following formula:~~

   ~~1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + Transmission Customer Annual kWh)~~

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW

(3) Total Annual Peak Load = 1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy = 13,369,466 kWh
(2) TNECO Annual Energy = 7,751,887,000 kWh
(3) Total Annual Energy 7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy = 20,054,199 kWh
(2) TNECO Annual Energy = 7,751,887,000 kWh
(3) Total Annual Energy 7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, the BIPCO Share Percentage in this example would be 0.19508%.

~~*2010 Peak Load Results*~~

~~(1) BIPCo Annual Peak Load = 3,604 kW~~
~~(2) Transmission Customer Annual Peak Load = 1,843,989 kW~~
~~(3) Total Annual Peak Load = 1,847,489 kW~~

~~(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%~~

~~*2010 Energy Results*~~

~~(1) 1.8* BIPCO Annual Energy = 20,054,199 kWh~~
~~(2) Transmission Customer Annual Energy = 7,751,887,000 kWh~~
~~(3) Total Annual Energy 7,771,941,199 kWh~~

~~(4) BIPCO Energy Ratio Share ((1)/(3)) = 0.25803%~~

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

May 4, 2015

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

Re: New England Power Company
Docket No. ER15-1466-000
Errata to Filing of First Revised Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86 Under ISO-NE OATT

Dear Secretary Bose:

On April 7, 2015, pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission's ("Commission")[2], New England Power Company d/b/a/ National Grid ("NEP") joined by ISO New England Inc. ("ISO-NE") (together, the "Filing Parties") submitted amendments to two Local Service Agreements ("LSAs"), designated as First Revised Service Agreement No. TSA-NEP-83 and First Revised Service Agreement No. TSA-NEP-86, respectively, under the ISO-NE OATT.

Due to an administrative oversight, Attachments A-1 and B-1, the marked tariff attachments showing the proposed revisions to the LSAs, were omitted from the filing submitted on April 7. Therefore, the Filing Parties now resubmit the April 7 filing with its original transmittal letter and a complete set of the attachments specified in that letter as part of this errata filing.

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1 16 U.S.C. § 824d.

2 18 C.F.R. Part 35.

The Filing Parties regret any inconvenience and request that the Commission accept the LSAs effective on the date requested in the April 7 filing, June 7, 2015. Please contact the undersigned with any questions regarding this filing.

Respectfully submitted,

/s/ Kenneth G. Jaffe
Kenneth G. Jaffe
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Amanda C. Downey
Counsel
National Grid USA
Service Company, Inc.
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Attorneys for New England Power Company d/b/a National Grid

/s/ Monica Gonzalez
Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Attorney for ISO New England Inc.

April 7, 2015

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

Re: New England Power Company
Docket No. ER15-____-000
Filing of First Revised Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86 Under ISO-NE OATT

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] New England Power Company d/b/a National Grid ("NEP") joined by ISO New England Inc. ("ISO-NE") (together, the "Filing Parties")[3] submit amendments to the following two Local Service Agreements ("LSAs"):

(1) the LSA among NEP, Block Island Power Company ("BIPCO"), and ISO New England Inc. ("ISO-NE"), designated as First Revised Service Agreement No. TSA-NEP-83 under the ISO-NE OATT; and

(2) the LSA among NEP, The Narragansett Electric Company ("Narragansett"), and ISO-NE, designated as First Revised Service Agreement No. TSA-NEP-86 under the ISO-NE OATT.

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1 16 U.S.C. § 824d.

2 18 C.F.R. Part 35.

3 NEP, and not ISO-NE, has the FPA section 205 rights over Schedule 21-NEP of the ISO-NE Open Access Transmission Tariff ("OATT"), pursuant to which NEP offers and administers Local Service. ISO-NE does not offer or administer Local Service and joins this filing solely to fulfill its obligations to file Local Service Agreements on the applicable Participating Transmission Owner ("PTO"), in accordance with Article 3.03(d)(ii) of the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs. *See ISO New England Inc.*, 124 FERC ¶ 61,297 (2008).

The Filing Parties request that the Commission accept the LSAs effective 61 days after the date of this filing, *i.e.*, June 7, 2015

I. Background

The original LSAs were accepted by the Commission on September 2, 2014, by delegated letter order in Docket No. ER14-2514-000. The LSAs were executed in order to include the Town of New Shoreham Project under the integrated facilities provisions of NEP's FERC Electric Tariff No. 1 ("Tariff No. 1").[4] The Town of New Shoreham Project is a public policy project authorized and directed by a Rhode Island statute of the same name.[5] The statute directs that:

> it is in the public interest for the state to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the [Rhode Island] mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland.[6]

The statute authorizes and sets forth a process for developing the Town of New Shoreham Project, an associated power purchase agreement, transmission arrangements, and recovery of related costs. It also permits Narragansett, at its option, to own, operate, or otherwise participate in the transmission cable project.[7]

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[4] Pursuant to those integrated facilities provisions, NEP supports the cost of the transmission facilities of its affiliate Narragansett, and Narragansett makes its transmission facilities available to be controlled and operated by NEP so that the transmission facilities of NEP and NEP's New England distribution affiliates are operated on an integrated basis and made available for open access transmission service in accordance with the ISO-NE OATT.

[5] Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7 (Supp. 2010).

[6] *Id.*, § 39-26.1-7(a).

[7] *Id.*, § 39-26.1-7(f). The statute specifies that "all costs incurred in the negotiation, administration, enforcement, transmission engineering associated with the design of the cable, and implementation of the project and agreement shall be recovered annually by the electric distribution company [*i.e.*, Narragansett] in electric distribution rates." *Id.*, § 39-26.1-7(d). The statute also directs that, should Narragansett own, operate, and maintain the cable, "the annual costs incurred by [Narragansett] directly or through transmission charges shall be recovered annually through a fully reconciling rate adjustment from customers of [Narragansett] and/or from the Block Island Power Company or its successor, subject to any federal approvals that may be required by law." *Id.*, § 39-26.1-7(f). Further, "[t]he revenue requirement for the annual cable costs shall be calculated in the same manner that the revenue requirement is calculated

The Deepwater Block Island Wind, LLC ("Block Island Wind") generation project, a 30-megawatt (nameplate) demonstration-scale offshore wind facility, is the offshore wind demonstration project described in the statute. Narragansett has agreed to construct, own, and operate the undersea cable between Block Island and the mainland and related facilities, which include a substation to be built on Block Island that will interconnect the Block Island Wind project to Narragansett's existing 34.5 kV system on the mainland. In addition, BIPCO, serving the Town of New Shoreham on Block Island, will interconnect to the same substation and will be electrically interconnected to the mainland for the first time by the same undersea cable. The cable will allow power to flow either from the Block Island Wind project to Block Island to the Rhode Island mainland, or from generators located on the mainland to Block Island, as needed. The Town of New Shoreham Project is currently estimated to be completed by late 2016.

As part of the package of Agreements necessary to implement the transaction and interconnect Block Island Wind to the mainland, NEP also filed, (1) a Large Generator Interconnection Agreement ("LGIA") with Block Island Wind which was accepted by the Commission by delegated letter order on September 2, 2014, in Docket No. ER14-2496-000 and (2) an amendment to Service Agreement No. 23 under NEP's Tariff No. 1 accepted by the Commission by delegated letter order on September 2, 2014, in Docket No. ER14-2493-000. NEP also terminated its previous Network Integration Transmission Service Agreement No. 108 with Narragansett which was part of the record in Docket No. ER14-2519.

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for other transmission facilities in Rhode Island for local network service under the jurisdiction of the federal energy regulatory commission." *Id.*

II. The LSAs

The LSAs being filed in this proceeding have been revised to address a concern raised by the Rhode Island Division of Public Utilities and Carriers ("Division") that the Block Island Transmission System ("BITS") Surcharge[8] calculated under the LSAs did not fully conform with the Rhode Island statute referenced above. Specifically, the Division was concerned that the calculation of the BIPCO Share Percentage did not fully comport with the Rhode Island General Law Section 39-26.7(f) which states:

> "The allocation of the costs related to the transmission cable through transmission rates or otherwise shall be structured so that the estimated impact on the typical residential customer bill for such transmission costs for customers in the Town of New Shoreham *shall be higher* than the estimated impact on the typical residential customer bill for customers on the mainland of the electric distribution company." (Emphasis added)

To address the issues raised by the Division, NEP modified the BITS Surcharge by introducing a collar to the calculation of the BIPCO Share Percentage such that the impact on the typical residential customer in the Town of New Shoreham cannot be lower than 120% of the impact on the typical residential customer of The Narragansett Electric Company. All parties have executed these First Revised LSAs to reflect that change. NEP is authorized to state the Division also supports this modification.

III. Effective Date

The Filing Parties request that the Commission accept the LSAs effective 61 days after the date of this filing, *i.e.*, June 7, 2015.

[8] *See* the BITS Surcharge provisions set forth in Part II, Section 2(p) of the LSAs and a referenced attachment in each LSA.

IV. Attachments

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Executed First Revised Service Agreement No. TSA-NEP-83;
Attachment A-1	Marked comparison between First Revised Service Agreement No. TSA-NEP-83 and Original Local Service Agreement No. TSA-NEP-83.
Attachment B	Executed First Revised Service Agreement No. TSA-NEP-86; and
Attachment B-1	Marked comparison between First Revised Service Agreement No. TSA-NEP-86 and Original Service Agreement No. TSA-NEP-86.

V. Description of the Filing Parties and Communications

NEP is a wholly owned subsidiary of National Grid USA. NEP is a public utility subject to the Commission's jurisdiction that owns transmission facilities located in New England. NEP's primary business is the transmission of electricity at wholesale to electric utilities and municipalities in New England. NEP operates transmission facilities that it owns directly as well as certain transmission facilities owned by its distribution affiliates in New England pursuant to integrated facilities agreements under Tariff No. 1. NEP acts as the transmission provider for itself and its New England distribution affiliates. NEP is a PTO under the terms of the TOA by and among the New England PTOs and ISO-NE. All of NEP's transmission facilities, including those owned by its New England distribution affiliates, are subject to the operating authority of ISO-NE under the terms of the TOA and are available for open access transmission service under the terms of Section II of the ISO-NE Tariff.

ISO-NE is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. ISO-NE operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the ISO-NE Transmission, Markets and Services Tariff and the Transmission Operating Agreement with the New England transmission owners. In its capacity as an RTO, ISO-NE also has the objective to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC").

Communications and correspondence regarding this filing should be addressed to the following individuals:

NEP:

Daniel Galaburda
Assistant General Counsel
and Director
National Grid USA
Service Company, Inc.
40 Sylvan Road
Waltham, MA 02451
(781) 907-2422
daniel.galaburda@nationalgrid.com

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Amanda C. Downey
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National Grid USA
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amanda.downey@nationalgrid.com

ISO-NE:

Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
(413) 535-4000
Fax: (413) 535-4379
mgonzalez@iso-ne.com

VI. Service

Copies of this filing have been served on Block Island Wind, Narragansett, BIPCO, the Rhode Island Division of Public Utilities and Carriers, and the Rhode Island Public Utilities Commission.

VII. Conclusion

For these reasons, the Filing Parties request that the Commission accept them effective 61 days from the date of filing, *i.e.*, June 7, 2015. Please contact the undersigned with any questions regarding this filing.

Respectfully submitted,

/s/ Kenneth G. Jaffe
Kenneth G. Jaffe
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Amanda C. Downey
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National Grid USA
Service Company, Inc.
40 Sylvan Road
Waltham, MA 02451

Attorneys for New England Power Company d/b/a National Grid

/s/ Monica Gonzalez
Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Attorney for ISO New England Inc.

ATTACHMENT A

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), Block Island Power Company, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

  __ Firm

  __ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: Clifford R. McGinness
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

    a. Term of Service: See 2 above.

    b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
Initially up to 4.6 MW and 15TWh of Network Load

d. Description of Local Network Load:
Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
At the Transmission Owner's Affiliate's 34.5 kV substation on Block Island.
Note: The metering is on the 34.5 kV side and the Transmission Owner owns the meter.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:
1-34.5kV breaker, 1-34.5/4.16kV/2.4kV transformer, 5kV insulated line to customer substation and associated equipment.

j. Project name:

k. Interconnecting Transmission Customer:

l. **Location:**

m. **Transformer nameplate rating:**

n. **Interconnection point:**

At 34.5kV at the Transmission Owner's Affiliate's 34.5kV substation on Block Island.

o. **Additional facilities and/or associated equipment:**

p. **Service under this Local Service Agreement shall be subject to the following charges:**

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. **Additional terms and conditions:**

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room. Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5 kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable.

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. **Planned work schedule.**

Estimated Time

Milestone (Activity)	**Period For Completion (# of months)**

6. **Payment schedule and costs.**

(Study grade estimate, +___% accuracy, year $s)

Milestone	**Amount ($)**

7. **Policy and practices for protection requirements for new or modified load interconnections.**

8. **Insurance requirements.**

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: C.R. McGinnes V President + COO 1/22/15

Name Title Date

C.R. MCGINNES

Print Name

Transmission Owner:

By: William L Malee Authorized Representative 1/8/15

Name Title Date

William L Malee

Print Name

The ISO:

By: V.P. System Planning 1/30/15

Name Title Date

Print Name

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Collar:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

ATTACHMENT A-1

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be ~~the lower of~~ BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share ~~or its Energy Ratio Share from the prior calendar year~~. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio ~~Share~~ Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio ~~Share~~Collar:

Illustrative Example:

2010 Annual Peak Load ~~Results~~

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy ~~Results~~Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

ATTACHMENT B

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

THE NARRAGANSETT ELECTRIC COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), The Narragansett Electric Company d/b/a/ National Grid, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take

and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
The Narragansett Electric Company
Attn: Mary K. Smith
280 Melrose Street
Providence, RI 02907

Transmission Owner:
New England Power Company
Attention: Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205

of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.
2. Service shall commence on the later of: (l) the date that termination becomes effective for the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997, by and between New England Power Company and The Narragansett Electric Company, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on or after the date that Contract Termination Charges, defined and set forth in the Stipulation and Agreement and the Amendment to the Service Agreement between the Transmission Customer and Transmission Owner under the Transmission Owner's FERC Electric Tariff, Original Volume 1 filed on May 30, 1997 in Docket No. ER97-680-000 and conditionally approved by the Commission on November 26, 1997(the "Restructuring Agreements"), are fully recovered from the Transmission Customer. Following that date, service under this Local Service Agreement shall continue until modified or terminated upon the written consent of the parties or upon five years advance written notice by any party to the others.

3. Specifications for Local Network Service.

a. Term of Service: See 2 above.

b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
1.8 GW and 7800 GWh

d. Description of Local Network Load:

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
See Attachment 1

f. List of non-Network Resource(s), to the extent known:
None

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer has executed a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

As of the execution date of this Local Service Agreement, the Schedule 21-NEP charges include a:

- Monthly demand charge with PTF and non-PTF components
- Transformer surcharge
- Meter surcharge
- Network load dispatch surcharge
- Third party support payments
- Direct Assignment Facility charge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 2)

q. Additional terms and conditions:

This Local Service Agreement amends and replaces the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997 and entered into by and between New England Power Company and The Narragansett Electric Company for the purpose of implementing wholesale competition or retail access for the Transmission Customer's retail customers pursuant to the Rhode Island Restructuring Act of 1996 ("URA"). Pursuant to the NITS Agreement, the following terms and conditions will remain in effect under the terms of this Local Service Agreement:

(i) In the event that Transmission Customer is denied recovery in its rates for local distribution service of access charges sufficient to collect the full amount of the Contract Termination Charges billed to Transmission Customer, its successors or assigns, by Transmission Owner, its successors or assigns, Transmission Owner, its successors or assigns, providing service over the transmission facilities covered by this Local Service Agreement shall collect the unrecovered balance of the Contract Termination Charges as a surcharge under this Local Service Agreement to the Transmission Customer or to any consumer taking delivery of electric energy over the transmission or distribution facilities of the Transmission Customer.

(ii) The obligations under this Local Service Agreement may be assigned only with the express written consent of the other parties, which consent shall not be unreasonably withheld, provided, however, that the Transmission Owner shall not be obligated to consent to any assignment that adversely affects the ability of the Transmission Owner to recover from the Transmission Customer the payments required to be made under the Tariff, and this Local Service Agreement, including any Contract Termination Charges that may be billed to Transmission Customer pursuant to the paragraph above.

(iii) The Transmission Owner has agreed to terminate those requirements of its FERC Electric Tariff, Original Volume No. 1 ("Tariff No. 1") that obligate the Transmission Customer to buy all of its electricity requirements under Tariff No. 1 and Transmission Customer has agreed to pay Contract Termination Charges pursuant to the Restructuring Agreements.

(iv) In no event shall the Transmission Owner bypass the Transmission Customer's distribution facilities and interconnect directly with a retail customer.

(v) To the extent ISO New England, Inc. or NEPOOL does not directly bill the Transmission Customer, any charges by ISO New England, Inc. or NEPOOL specifically incurred by the Transmission Owner, as a result of services provided to the Transmission Customer, will be directly assigned to the Transmission Customer as provided for under Section 24.6 of Schedule 21-NEP. The Transmission Owner will determine the direct charges to the Transmission Customer on the basis of the Transmission Customer's contribution to the incurrence of those charges using the same allocation methodology used by ISO New

England, Inc. or NEPOOL to allocate those costs to the Transmission Owner.

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practiccs for protcction requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service N/A

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time	
Milestone	Period For Completion
(Activity)	(# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By:	President	1/12/15
Name	Title	Date

Timothy F. Horan
Print Name

Transmission Owner:

By:	Authorized Representative	1/12/15
Name	Title	Date

William L Malee
Print Name

The ISO:

By:	V.P. System Planning	1/21/15
Name	Title	Date

Stephen J. Rourke
Print Name

Attachment 1

The Narragansett Electric Company

Points of Delivery

Main District
Admiral Street Substation
Blackburn Substation
Bristol Substation
Clarkson Street Substation
Davisville Substation
Drumrock Substation
EMI Tiverton Station Service
Farnum Pike Substation
FPL RISEP Station Service
Franklin Square Substation
Johnston Substation
Kent County Substation
Kenyon Substation
Kilvert Substation
Lincoln Ave. Substation
Mink Street Substation
Old Baptist Road Substation
Phillipsdale Substation
Point Street Substation
Pontiac Substation
Putnam Pike
Sockanosset Substation
South Street Station
Tiverton Substation
Tower Hill Substation
Wampanoag Substation
Warren Substation
West Cranston Substation
West Kingston Substation
Wolf Hill Substation
Wood River Substation
Woonsocket Substation

Blackstone Valley
Nasonville B23 Line from W. Farnum
West Farnum tap off 174
Farnum off H 17 Line
Riverside - R9/J16/H17
Pawtucket No. 1 Station X3/P11/T7
Staples J16/Q10
Vallev R9P11
Washington V148 from Robinson Ave
Ocean State Power Station Service

Newport
Canonicus St. M13L14

Attachment 1

Metering Points (To the extent they differ from a Point of Delivery)

Main District
Pawtucket Power
Johnston Landfill
Valley Hydro
Cranston Landfill

Blackstone Valley
Roosevelt Hydro
Blackstone Hydro, Inc.
Blackstone Hydro Assoc.
Pawtucket #2 Hydro
Woonsocket Hydro

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO Share Percentage. The BIPCO Share Percentage shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar year as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy = 13,369,466 kWh

(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh
(4) Minimum Energy Ratio Share ((1)/(3)) =	0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh
(4) Maximum Energy Ratio Share ((1)/(3)) =	0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, the BIPCO Share Percentage in this example would be 0.19508%.

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

ATTACHMENT B-1

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO ~~Load Ratio~~ Share Percentage. The BIPCO ~~Load Ratio~~ Share Percentage shall be ~~the lower of~~ BIPCO's Annual Peak Load Ratio Share from the prior calendar year as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. ~~or its Energy Ratio Share from the prior calendar year.~~ The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

~~4. BIPCO's Energy Ratio Share shall be determined as a percentage according the the following formula:~~

   ~~1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + Transmission Customer Annual kWh)~~

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW

(3) Total Annual Peak Load = 1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy = 13,369,466 kWh
(2) TNECO Annual Energy = 7,751,887,000 kWh
(3) Total Annual Energy 7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy = 20,054,199 kWh
(2) TNECO Annual Energy = 7,751,887,000 kWh
(3) Total Annual Energy 7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, the BIPCO Share Percentage in this example would be 0.19508%.

~~*2010 Peak Load Results*~~

~~(1) BIPCo Annual Peak Load = 3,604 kW~~
~~(2) Transmission Customer Annual Peak Load = 1,843,989 kW~~
~~(3) Total Annual Peak Load = 1,847,489 kW~~

~~(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%~~

~~*2010 Energy Results*~~

~~(1) 1.8* BIPCO Annual Energy = 20,054,199 kWh~~
~~(2) Transmission Customer Annual Energy = 7,751,887,000 kWh~~
~~(3) Total Annual Energy 7,771,941,199 kWh~~

~~(4) BIPCO Energy Ratio Share ((1)/(3)) = 0.25803%~~

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

ISO New England Inc. and
New England Power Company
Docket No. ER15-1466-001

Issued: 6/22/15

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Alston & Bird LLP
The Atlantic Building
950 F Street NW
Washington, DC 20004

Attention: Monica Gonzalez, Esq.
Attorney for ISO New England Inc.

Kenneth G. Jaffe, Esq.
Attorney for New England Power Company

Reference: Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86

Dear Ms. Gonzalez and Mr. Jaffe:

On April 7, 2015, as amended on May 4, 2015, ISO New England Inc. (ISO-NE) and New England Power Company jointly submitted amendments to two executed Local Service Agreements (LSA). The first LSA is by and among NEP, Block Island Power Company (Block Island Power)[1], and ISO-NE, while the other is by and among NEP, The Narragansett Electric Company (Narragansett)[2] and ISO-NE. The revisions address the concern raised by the Rhode Island

[1] ISO New England Inc., ISO New England Inc. Agreements and Contracts, Block Island LSA, LSA - TSA-NEP-83 NEP, Block Island Power and ISO-NE, 2.0.0.

[2] ISO New England Inc., ISO New England Inc. Agreements and Contracts, Narragansett LSA, LSA - TSA-NEP-86 NEP, Narragansett and ISO-NE, 2.0.0.

Division of Public Utilities and Carriers that the Block Island Transformation System Surcharge calculated under the LSAs did not fully comport with the Rhode Island General Law Section 39-26.7(f).

Pursuant to the authority delegated to the Director, Division of Electric Power Regulation – East, under 18 C.F.R. § 375.307, your submittal is accepted for filing, effective June 7, 2015, as requested.

The filings were noticed on April 7, 2015 and May 5, 2015, with comments, interventions, and protests due on or before April 28, 2015 and May 26, 2015, respectively. Pursuant to Rule 214 (18 C.F.R. § 385.214 (2014)), to the extent that any timely filed motions to intervene and any motion to intervene out-of-time were filed before the issuance date of this order, such interventions are granted. Granting late interventions at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties.

This acceptance for filing shall not be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in your filing; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the ISO-NE or NEP.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Kurt M. Longo, Director
Division of Electric Power
Regulation – East

December 28, 2018

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

Re: New England Power Company
Docket No. ER19-____-000

Filing of Second Revised Service Agreement No. TSA-NEP-83
Under the ISO-NE OATT

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] New England Power Company d/b/a National Grid ("NEP") joined by ISO New England Inc. ("ISO-NE") (together, the "Filing Parties")[3] submit an amendment to the Local Service Agreement ("LSA") among NEP, Block Island Power Company ("BIPCO"), and ISO-NE to make a number of clarifying and ministerial changes. The LSA, as amended by this filing, is designated as Second Revised Service Agreement No. TSA-NEP-83 under the ISO-NE OATT.

The Filing Parties request that the Commission accept the amended LSA effective as of January 1, 2019, the effective date agreed to by NEP, ISO-NE, and BIPCO.

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1 16 U.S.C. § 824d.

2 18 C.F.R. Part 35.

3 NEP, and not ISO-NE, has the FPA section 205 rights over Schedule 21-NEP of the ISO-NE Open Access Transmission Tariff ("OATT"), pursuant to which NEP offers and administers Local Service. The ISO-NE OATT is contained in Section II of the ISO-NE Transmission, Markets, and Services Tariff ("Tariff"). ISO-NE does not offer or administer Local Service and joins this filing solely to fulfill its obligations to file Local Service Agreements on behalf of the applicable Participating Transmission Owner ("PTO"), in accordance with Article 3.03(d)(ii) of the Transmission Operating Agreement ("TOA") between the New England PTOs and ISO-NE. *See ISO New England Inc.*, 124 FERC ¶ 61,297 (2008).

I. Background

A. The Filing Parties

NEP is a wholly owned subsidiary of National Grid USA. NEP is a public utility subject to the Commission's jurisdiction that owns transmission facilities located in New England. NEP's primary business is the transmission of electricity at wholesale to customers in New England. NEP operates transmission facilities that it owns directly as well as certain transmission facilities owned by its distribution affiliates in New England pursuant to integrated facilities agreements under NEP's FERC Electric Tariff No. 1 ("Tariff No. 1"). NEP acts as the transmission provider for itself and its New England distribution affiliates. NEP is a PTO under the terms of the TOA. All of NEP's transmission facilities, including those owned by its New England distribution affiliates, are subject to the operating authority of ISO-NE under the terms of the TOA and are available for open access transmission service under the ISO-NE OATT.

ISO-NE is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. ISO-NE plans and operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the ISO-NE Tariff and the TOA. In its capacity as an RTO, ISO-NE also has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC").

B. The LSA

The original version of the LSA (designated as Original Service Agreement No. TSA-NEP-83 under the ISO-NE OATT) was executed in 2014 in order to include the Town of New Shoreham Project under the integrated facilities provisions of Tariff No. 1.[4] The Commission accepted the original version of the LSA on September 2, 2014, by a letter order issued in Docket No. ER14-2514-000.

The Town of New Shoreham Project is a public policy project authorized and directed by a Rhode Island statute of the same name.[5] The statute directs that "it is in the public interest for the state to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the [Rhode Island] mainland."[6] The statute authorizes and sets forth a process for developing the Town of New Shoreham Project, an associated power purchase agreement, transmission

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[4] Pursuant to those integrated facilities provisions, NEP supports the cost of the transmission facilities of its affiliate The Narragansett Electric Company ("Narragansett"), and Narragansett makes its transmission facilities available to be controlled and operated by NEP so that the transmission facilities of NEP and NEP's New England distribution affiliates are operated on an integrated basis and made available for open access transmission service in accordance with the ISO-NE OATT.

[5] Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7 (Supp. 2010).

[6] *Id.*, § 39-26.1-7(a).

arrangements, and recovery of related costs. It also permits Narragansett, at its option, to own, operate, or otherwise participate in the transmission cable project.[7]

The Deepwater Block Island Wind, LLC ("Block Island Wind") generation project, a 30-megawatt (nameplate) demonstration-scale offshore wind facility, is the offshore wind demonstration project described in the statute. Narragansett agreed to construct, own, and operate the undersea cable between Block Island and the mainland and related facilities, which include a substation built on Block Island to interconnect the Block Island Wind project to Narragansett's existing 34.5 kV system on the mainland. In addition, BIPCO, serving the Town of New Shoreham on Block Island, agreed to interconnect to the same substation and be electrically interconnected to the mainland for the first time by the same undersea cable. The cable allows power to flow either from the Block Island Wind project to Block Island to the Rhode Island mainland, or from generators located on the mainland to Block Island, as needed. The Block Island Wind generation project was completed in late 2016 and the cable was completed in 2017.[8]

In 2015, the Filing Parties filed an amendment to the LSA (designated as First Revised Service Agreement No. TSA-NEP-83 under the ISO-NE OATT) to revise the provisions therein regarding the calculation of the Block Island Transmission System ("BITS") Surcharge. The Commission accepted that filing by a letter order issued on June 22, 2015 in Docket No. ER15-1466-001.

II. The Instant Amendment to the LSA

The Filing Parties propose to amend the LSA to make the following clarifying and ministerial changes:

- Clarify that the Transmission Customer (*i.e.*, BIPCO) is responsible for telecommunications circuits;[9]

- Update the list of interconnection facilities and associated equipment, and specify that the Transmission Customer has elected to pay for the interconnection facilities via a Direct Assignment Facilities charge with no Contribution in Aid of Construction;[10]

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7 *Id.*, § 39-26.1-7(f). The statute specifies that "all costs incurred in the negotiation, administration, enforcement, transmission engineering associated with the design of the cable, and implementation of the project and agreement shall be recovered annually by the electric distribution company [*i.e.*, Narragansett] in electric distribution rates." *Id.*, § 39-26.1-7(d).

8 As part of the package of agreements necessary to interconnect Block Island Wind to the mainland, NEP filed: (1) a Large Generator Interconnection Agreement with Block Island Wind, which the Commission accepted by a letter order issued on September 2, 2014 in Docket No. ER14-2496-000; and (2) an amendment to Service Agreement No. 23 under NEP's Tariff No. 1, which the Commission accepted by a letter order issued on September 2, 2014 in Docket No. ER14-2493-000.

9 *See* amended LSA, Part II, Section 3(e).

10 *See id.*, Part II, Sections 3(i) and 5.

- List the name of the Transmission Customer and its location;[11]
- List the transformer nameplate rating;[12]
- Clarify the point of change in ownership at the interconnection point;[13]
- List the work schedule (which has already been completed);[14]
- Update contact information;[15] and
- Correct minor formatting issues.[16]

III. Effective Date

The Filing Parties request that the Commission accept the LSA as amended by this filing effective as of January 1, 2019, the effective date agreed to by NEP, ISO-NE, and BIPCO.[17] The Commission's regulations require service agreements to be filed not more than 30 days after service under the agreements has commenced.[18] The Filing Parties are submitting the amended LSA in advance of the requested January 1 effective date.

IV. Attachments

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Executed Second Revised Service Agreement No. TSA-NEP-83; and
Attachment A-1	Marked comparison between Second Revised Service Agreement No. TSA-NEP-83 and First Revised Service Agreement No. TSA-NEP-83.

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11 *See id.*, Part II, Sections 3(k)-(l).

12 *See id.*, Part II, Section 3(m).

13 *See id.*, Part II, Section 3(n).

14 *See id.*, Part II, Section 4.

15 *See id.*, Part I, Section 7, and Part II, Section 3(h).

16 *See id.*, Part I, Sections 1 and 7, Part II, Section 3(d), and Part III, Section 4(c).

17 *See id.*, Recitals.

18 18 C.F.R. § 35.3(a)(2).

V. Communications

Communications and correspondence regarding this filing should be addressed to the following individuals:

NEP:

Christopher J. Novak
Senior Counsel
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40 Sylvan Road
Waltham, MA 02451
(781) 907-2112
chris.novak@nationalgrid.com

Kathryn Cox-Arslan
Director, Commercial Services
National Grid USA
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kathryn.cox-arslan@nationalgrid.com

Sean Atkins
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ISO-NE:

Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
(413) 535-4178
Fax: (413) 535-4379
mgonzalez@iso-ne.com

VI. Service

Copies of this filing have been served on Block Island Wind, Narragansett, BIPCO, the Rhode Island Division of Public Utilities and Carriers, and the Rhode Island Public Utilities Commission.

VII. Conclusion

For these reasons, the Filing Parties request that the Commission accept the amended LSA contained in this filing effective as of January 1, 2019. Please contact the undersigned with any questions regarding this filing.

Respectfully submitted,

/s/ Christopher J. Novak
Christopher J. Novak
Senior Counsel
National Grid USA
Service Company, Inc.
40 Sylvan Road
Waltham, MA 02451

/s/ Sean Atkins
Sean Atkins
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Attorneys for New England Power Company d/b/a National Grid

/s/ Monica Gonzalez
Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Attorney for ISO New England Inc.

ATTACHMENT A

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND, INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of January 1, 2019 is entered into, by and between New England Power Company d/b/a/ National Grid , a corporation organized and existing under the laws of the State/Commonwealth of Massachusetts ("Transmission Owner"), Block Island Power Company , a corporation organized and existing under the laws of the State/Commonwealth of Rhode Island ("Transmission Customer") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

_X_ Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: Jeffery M. Wright
P.O. Box 518
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

    a. Term of Service: See 2 above.

    b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:

Initially up to 4 MW and 15TWh of Network Load

d. Description of Local Network Load:

Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:

At the Transmission Owner's Affiliate's 34.5kV substation on Block Island. Note: The metering is on the 34.5kV side and the Transmission Owner owns the meter. The Transmission Customer is responsible for the telecommunications circuits.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:

The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent: Energy New England

Authority of Designated Agent: Christina Beaudry

Term of Designated Agent's authority: December 31, 2021

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

(1) 34.5kV Breaker, a dead end structure, and associated equipment within Transmission Owner's Affiliate's 34.5kVkV substation on Block Island, and (2) steel structures, 5 kV conductors, and associated hardware to interconnect

to Transmission Customer's facilities.

j. Project name:

k. Interconnecting Transmission Customer: Block Island Power Company

l. Location: 100 Ocean Ave, New Shoreham, Rhode Island

m. Transformer nameplate rating: 34.5/4.16kV/2.4kV transformer

n. Interconnection point:

At the Transmission Owner's Affiliate's 34.5kV substation on Block Island. The point of change of ownership is at Transmission Customer's Pole 3.

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. Additional terms and conditions:

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room.

Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable.

4. Planned work schedule.

Estimated Time

Milestone (Activity)		Period For Completion (# of months)
Construction Complete	03/22/2017	
In-Service Date	05/01/2017	

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone Amount ($)

Transmission Customer has elected to pay for interconnection facilities in 3(i) via a Direct Assignment Facilities charge with no Contribution in Aid of Construction.

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) __________________, or (2) the date on

which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ___________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time	
Milestone	Period For Completion
(Activity)	(# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By:__________________ Authorized Representative — Nov 26, 18
Name: Jeffery M. Wright — Title: President — Date

Transmission Owner:

By:__________________ Authorized Representative — NOV 19 2018
Name: Kathryn Cox-Arslan — Title: Director, Commercial Services — Date

The ISO:

By:__________________ Authorized Representative — 12/26/2018
Name: — Title: — Date

Stephen J. Rourke — V.P. System Planning

Attachment 1

Block Island Transmission System (BITS) Surcharge

This Attachment 1 applies to charges under the Tariff for Block Island Transmission System (BITS") facilities owned or leased by the Transmission Owner's Affiliate, The Narragansett Electric Company, and constructed to interconnect Transmission Customer and Deepwater Block Island Wind, LLC to the New England Transmission System in accordance with the Rhode Island General Laws, § 39-26.1-7, known as the Town of New Shoreham Project ("Project"). The intent of the Project is to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland. Provided that the Project goes forward as intended, the annual costs incurred by The Narragansett Electric Company ("TNECO") for the BITS facilities shall be recovered annually from its customers and from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, the provisions of which are set forth below, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission Service Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- 22 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KV switching station on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately 0.86 miles of combined overhead and underground infrastructure on Block Island; and
- Approximately 2 miles of combined overhead and underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Collar:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

ATTACHMENT A-1

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND, INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of ~~February~~January 1, ~~2015~~2019 is entered into, by and between New England Power Company d/b/a/ National Grid , a corporation organized and existing under the laws of the State/Commonwealth of Massachusetts ("Transmission Owner"), Block Island Power Company , a corporation organized and existing under the laws of the State/Commonwealth of Rhode Island ("Transmission Customer") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

_X_ Local Network Service

__ Local Point-To-Point Service

__ -Firm

__- Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: ~~Clifford R. McGinness~~Jeffery M. Wright
P.O. Box 518
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

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9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

    a. Term of Service: See 2 above.

    b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
Initially up to 4 MW and 15TWh of Network Load

d. Description of Local Network Load:
Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
At the Transmission Owner's Affiliate's 34.~~5kVkV~~5kV substation on Block Island.
Note: The metering is on the 34.5kV side and the Transmission Owner owns the meter. The Transmission Customer is responsible for the telecommunications circuits.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent: Energy New England

Authority of Designated Agent: Christina Beaudry

Term of Designated Agent's authority: December 31, 2021

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:
~~1-34.5kV breaker, 1-34.5/4.16kV/2.4kV transformer, 5kV insulated line to customer substation and associated equipment.~~

(1) 34.5kV Breaker, a dead end structure, and associated equipment within Transmission Owner's Affiliate's 34.5kVkV substation on Block Island, and (2) steel structures, 5 kV conductors, and associated hardware to interconnect to Transmission Customer's facilities.

j. Project name:

k. Interconnecting Transmission Customer: Block Island Power Company

l. Location: 100 Ocean Ave, New Shoreham, Rhode Island

m. Transformer nameplate rating: 34.5/4.16kV/2.4kV transformer

n. Interconnection point:

At ~~34.5kV at~~ the Transmission Owner's Affiliate's 34.5kV substation on Block Island. The point of change of ownership is at Transmission Customer's Pole 3.

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. Additional terms and conditions:

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room. Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable.

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)
Construction Complete	03/22/2017
In-Service Date	05/01/2017

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone Amount ($)

Transmission Customer has elected to pay for interconnection facilities in 3(i) via a Direct Assignment Facilities charge with no Contribution in Aid of Construction.

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the

ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) __________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ___________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

Formatted: Indent: Left: 0.5", Hanging: 0.5" k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Milestone (Activity)	Estimated Time Period For Completion (# of months)

6. Payment schedule and costs.
(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: ______________________

Name: Jeffery M. Wright Title: President ______________

Date

~~Name Title Date~~

~~Albert R. Casazza~~

~~Print Name~~

Transmission Owner:

~~By: Authorized Representative~~

By: ______________________

Name: Kathryn Cox-Arslan Title: Director, Commercial Services Date

~~William L. Malee~~

The ISO:

~~By:~~

By: ______________________

Name: ______________ Title: ______________

Date

____

~~Print Name~~

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Attachment 1

Block Island Transmission System (BITS) Surcharge

This Attachment 1 applies to charges under the Tariff for Block Island Transmission System (BITS") facilities owned or leased by the Transmission Owner's Affiliate, The Narragansett Electric Company, and constructed to interconnect Transmission Customer and Deepwater Block Island Wind, LLC to the New England Transmission System in accordance with the Rhode Island General Laws, § 39-26.1-7, known as the Town of New Shoreham Project ("Project"). The intent of the Project is to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland. Provided that the Project goes forward as intended, the annual costs incurred by The Narragansett Electric Company ("TNECO") for the BITS facilities shall be recovered annually from its customers and from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, the provisions of which are set forth below, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission Service Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- 22 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KV switching station on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately 0.86 miles of combined overhead and underground infrastructure on Block Island; and
- Approximately 2 miles of combined overhead and underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Collar:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer’s Share Percentage in this example would be 0.19508%.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

New England Power Company and
ISO New England Inc.
Docket No. ER19-707-000

Issued: 2/22/19

Christopher J. Novak
National Grid USA Service Company, Inc.
40 Sylvan Road
Waltham, MA 02451

Monica Gonzalez
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Sean Atkins
Alston & Bird LLP
950 F Street, NW
Washington, DC 20004

Reference: Second Revised Service Agreement

On December 28, 2018, New England Power Company d/b/a National Grid and ISO New England Inc. (ISO-NE) jointly filed an amendment to the Local Service Agreement (LSA) among New England Power Company, Block Island Power Company, and ISO-NE.[1] You state that the amendment to the LSA includes a number of clarifying and ministerial changes.

Pursuant to the authority delegated to the Director, Division of Electric Power Regulation – East, under 18 C.F.R. § 375.307, your submittal is accepted for filing, effective January 1, 2019, as requested, subject to the following condition. Within 30 days of the date of this order, New England Power Company and ISO-NE should submit a filing to correct the title of the Second Revised Service Agreement in eTariff from

[1] ISO New England Inc., ISO New England Inc. Agreements and Contracts, ISO/NEP/BIPCO LSA, Second Revised Service Agreement No. TSA-NEP-82, 0.0.0.

TSA-NEP-82 to TSA-NEP-83 as designated under the ISO-NE Open Access Transmission Tariff.

The filing was noticed on December 28, 2018, with comments, interventions, and protests due on or before January 18, 2019. Pursuant to Rule 214 (18 C.F.R. § 385.214 (2018)), to the extent that any timely filed motions to intervene and any motion to intervene out-of-time were filed before the issuance date of this order, such interventions are granted. Granting late interventions at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties.

This acceptance for filing shall not be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in your filing; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against New England Power Company or ISO-NE.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Issued by: Kurt M. Longo, Director, Division of Electric Power Regulation – East

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND, INC.

SCHEDULE 21
ATTACHMENT A
FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of January 1, 2019 is entered into, by and between New England Power Company d/b/a/ National Grid , a corporation organized and existing under the laws of the State/Commonwealth of Massachusetts ("Transmission Owner"), Block Island Power Company , a corporation organized and existing under the laws of the State/Commonwealth of Rhode Island ("Transmission Customer") and ISO New England, Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

_X_ Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: Jeffery M. Wright
P.O. Box 518
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

   a. Term of Service: See 2 above.

   b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:

Initially up to 4 MW and 15TWh of Network Load

d. Description of Local Network Load:

Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:

At the Transmission Owner's Affiliate's 34.5kV substation on Block Island. Note: The metering is on the 34.5kV side and the Transmission Owner owns the meter. The Transmission Customer is responsible for the telecommunications circuits.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:

The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent: Energy New England

Authority of Designated Agent: Christina Beaudry

Term of Designated Agent's authority: December 31, 2021

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

(1) 34.5kV Breaker, a dead end structure, and associated equipment within Transmission Owner's Affiliate's 34.5kVkV substation on Block Island, and (2) steel structures, 5 kV conductors, and associated hardware to interconnect

to Transmission Customer's facilities.

j. Project name:

k. Interconnecting Transmission Customer: Block Island Power Company

l. Location: 100 Ocean Ave, New Shoreham, Rhode Island

m. Transformer nameplate rating: 34.5/4.16kV/2.4kV transformer

n. Interconnection point:

At the Transmission Owner's Affiliate's 34.5kV substation on Block Island. The point of change of ownership is at Transmission Customer's Pole 3.

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. Additional terms and conditions:

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room.

Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable.

4. Planned work schedule.

Estimated Time

Milestone (Activity)		Period For Completion (# of months)
Construction Complete	03/22/2017	
In-Service Date	05/01/2017	

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone Amount ($)

Transmission Customer has elected to pay for interconnection facilities in 3(i) via a Direct Assignment Facilities charge with no Contribution in Aid of Construction.

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) __________________, or (2) the date on

which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ___________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone	Period For Completion
(Activity)	(# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: ______________ Authorized Representative — Nov 26, 18
Name: Jeffery M. Wright — Title: President — Date

Transmission Owner:

By: ______________ Authorized Representative — NOV 19 2018
Name: Kathryn Cox-Arslan — Title: Director, Commercial Services — Date

The ISO:

By: ______________ Authorized Representative — 12/26/2018
Name: Stephen J. Rourke — Title: V.P. System Planning — Date

Attachment 1

Block Island Transmission System (BITS) Surcharge

This Attachment 1 applies to charges under the Tariff for Block Island Transmission System (BITS") facilities owned or leased by the Transmission Owner's Affiliate, The Narragansett Electric Company, and constructed to interconnect Transmission Customer and Deepwater Block Island Wind, LLC to the New England Transmission System in accordance with the Rhode Island General Laws, § 39-26.1-7, known as the Town of New Shoreham Project ("Project"). The intent of the Project is to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland. Provided that the Project goes forward as intended, the annual costs incurred by The Narragansett Electric Company ("TNECO") for the BITS facilities shall be recovered annually from its customers and from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, the provisions of which are set forth below, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission Service Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- 22 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KV switching station on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately 0.86 miles of combined overhead and underground infrastructure on Block Island; and
- Approximately 2 miles of combined overhead and underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Collar:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

THE NARRAGANSETT ELECTRIC COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), The Narragansett Electric Company d/b/a/ National Grid, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take

and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
The Narragansett Electric Company
Attn: Mary K. Smith
280 Melrose Street
Providence, RI 02907

Transmission Owner:
New England Power Company
Attention: Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205

of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.
2. Service shall commence on the later of: (l) the date that termination becomes effective for the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997, by and between New England Power Company and The Narragansett Electric Company, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on or after the date that Contract Termination Charges, defined and set forth in the Stipulation and Agreement and the Amendment to the Service Agreement between the Transmission Customer and Transmission Owner under the Transmission Owner's FERC Electric Tariff, Original Volume 1 filed on May 30, 1997 in Docket No. ER97-680-000 and conditionally approved by the Commission on November 26, 1997(the "Restructuring Agreements"), are fully recovered from the Transmission Customer. Following that date, service under this Local Service Agreement shall continue until modified or terminated upon the written consent of the parties or upon five years advance written notice by any party to the others.

3. Specifications for Local Network Service.

a. Term of Service: See 2 above.

b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
1.8 GW and 7800 GWh

d. Description of Local Network Load:

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
See Attachment 1

f. List of non-Network Resource(s), to the extent known:
None

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer has executed a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

As of the execution date of this Local Service Agreement, the Schedule 21-NEP charges include a:

- Monthly demand charge with PTF and non-PTF components
- Transformer surcharge
- Meter surcharge
- Network load dispatch surcharge
- Third party support payments
- Direct Assignment Facility charge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 2)

q. Additional terms and conditions:

This Local Service Agreement amends and replaces the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997 and entered into by and between New England Power Company and The Narragansett Electric Company for the purpose of implementing wholesale competition or retail access for the Transmission Customer's retail customers pursuant to the Rhode Island Restructuring Act of 1996 ("URA"). Pursuant to the NITS Agreement, the following terms and conditions will remain in effect under the terms of this Local Service Agreement:

(i) In the event that Transmission Customer is denied recovery in its rates for local distribution service of access charges sufficient to collect the full amount of the Contract Termination Charges billed to Transmission Customer, its successors or assigns, by Transmission Owner, its successors or assigns, Transmission Owner, its successors or assigns, providing service over the transmission facilities covered by this Local Service Agreement shall collect the unrecovered balance of the Contract Termination Charges as a surcharge under this Local Service Agreement to the Transmission Customer or to any consumer taking delivery of electric energy over the transmission or distribution facilities of the Transmission Customer.

(ii) The obligations under this Local Service Agreement may be assigned only with the express written consent of the other parties, which consent shall not be unreasonably withheld, provided, however, that the Transmission Owner shall not be obligated to consent to any assignment that adversely affects the ability of the Transmission Owner to recover from the Transmission Customer the payments required to be made under the Tariff, and this Local Service Agreement, including any Contract Termination Charges that may be billed to Transmission Customer pursuant to the paragraph above.

(iii)The Transmission Owner has agreed to terminate those requirements of its FERC Electric Tariff, Original Volume No. 1 ("Tariff No. 1") that obligate the Transmission Customer to buy all of its electricity requirements under Tariff No. 1 and Transmission Customer has agreed to pay Contract Termination Charges pursuant to the Restructuring Agreements.

(iv)In no event shall the Transmission Owner bypass the Transmission Customer's distribution facilities and interconnect directly with a retail customer.

(v) To the extent ISO New England, Inc. or NEPOOL does not directly bill the Transmission Customer, any charges by ISO New England, Inc. or NEPOOL specifically incurred by the Transmission Owner, as a result of services provided to the Transmission Customer, will be directly assigned to the Transmission Customer as provided for under Section 24.6 of Schedule 21-NEP. The Transmission Owner will determine the direct charges to the Transmission Customer on the basis of the Transmission Customer's contribution to the incurrence of those charges using the same allocation methodology used by ISO New

England, Inc. or NEPOOL to allocate those costs to the Transmission Owner.

4. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service N/A

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on ________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.
Estimated Time

Milestone (Activity)	Period For Completion (# of months)

6. Payment schedule and costs.
(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: ______________ President 1/12/15

Name Title Date

Timothy F. Horan

Print Name

Transmission Owner:

By: William L Malee Authorized Representative 1/12/15

Name Title Date

William L Malee

Print Name

The ISO:

By: ______________ V.P. System Planning 1/21/15

Name Title Date

Stephen J. Rourke

Print Name

Attachment 1

The Narragansett Electric Company

Points of Delivery

Main District
Admiral Street Substation
Blackburn Substation
Bristol Substation
Clarkson Street Substation
Davisville Substation
Drumrock Substation
EMI Tiverton Station Service
Farnum Pike Substation
FPL RISEP Station Service
Franklin Square Substation
Johnston Substation
Kent County Substation
Kenyon Substation
Kilvert Substation
Lincoln Ave. Substation
Mink Street Substation
Old Baptist Road Substation
Phillipsdale Substation
Point Street Substation
Pontiac Substation
Putnam Pike
Sockanosset Substation
South Street Station
Tiverton Substation
Tower Hill Substation
Wampanoag Substation
Warren Substation
West Cranston Substation
West Kingston Substation
Wolf Hill Substation
Wood River Substation
Woonsocket Substation

Blackstone Valley
Nasonville B23 Line from W. Farnum
West Farnum tap off 174
Farnum off H 17 Line
Riverside - R9/J16/H17
Pawtucket No. 1 Station X3/P11/T7
Staples J16/Q10
Vallev R9P11
Washington V148 from Robinson Ave
Ocean State Power Station Service

Newport
Canonicus St. M13L14

Attachment 1

Metering Points (To the extent they differ from a Point of Delivery)

Main District
Pawtucket Power
Johnston Landfill
Valley Hydro
Cranston Landfill

Blackstone Valley
Roosevelt Hydro
Blackstone Hydro, Inc.
Blackstone Hydro Assoc.
Pawtucket #2 Hydro
Woonsocket Hydro

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO Share Percentage. The BIPCO Share Percentage shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar year as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh

(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh
(4) Minimum Energy Ratio Share ((1)/(3)) =	0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh
(4) Maximum Energy Ratio Share ((1)/(3)) =	0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, the BIPCO Share Percentage in this example would be 0.19508%.

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

PUC 3-4

Request:

Please provide schedules showing how the revenue requirement for the BITS project was split between Block Island and Narragansett Electric and ultimately charged to each for 2019 by NEP.

Response:

Please refer to Attachment PUC 3-4 which provides the detailed calculations showing how the BITS Surcharge was calculated and billed to Block Island and Narragansett Electric.

The Narragansett Electric Company
Integrated Facilities Agreement
Summary of BITS Surcharge
For Costs in Calendar Year 2019

Line	Billing Month (a)	Service Month (a)	(A) Gross Plant	(B) Carrying Charge (b)	(C) Share % (c)	(D) = [(A) x (B) x (C)] / 12 BITS Surcharge
The Narragansett Electric Company Charges						
1	Feb-2019	Jan-2019	$113,500,009	17.25%	99.73%	$1,627,157
2	Mar-2019	Feb-2019	$113,523,131	17.25%	99.73%	$1,627,489
3	Apr-2019	Mar-2019	$113,855,096	17.25%	99.73%	$1,632,248
4	May-2019	Apr-2019	$113,912,570	17.25%	99.73%	$1,633,072
5	Jun-2019	May-2019	$113,928,017	17.25%	99.73%	$1,633,293
6	Jul-2019	Jun-2019	$113,947,385	16.63%	99.73%	$1,575,210
7	Aug-2019	Jul-2019	$113,971,509	16.63%	99.73%	$1,575,544
8	Sep-2019	Aug-2019	$113,981,288	16.56%	99.73%	$1,568,837
9	Oct-2019	Sep-2019	$113,995,356	16.56%	99.73%	$1,569,031
10	Nov-2019	Oct-2019	$114,103,482	16.56%	99.73%	$1,570,519
11	Dec-2019	Nov-2019	$114,122,449	16.56%	99.73%	$1,570,780
12	Jan-2020	Dec-2019	$114,160,806	16.63%	99.73%	$1,578,160
13	Total (Sum Lines 2 thru 12)					$19,161,342
Block Island Power Company Charges						
14	Feb-2019	Jan-2019	$113,500,009	17.25%	0.27%	$4,405
15	Mar-2019	Feb-2019	$113,523,131	17.25%	0.27%	$4,406
16	Apr-2019	Mar-2019	$113,855,096	17.25%	0.27%	$4,419
17	May-2019	Apr-2019	$113,912,570	17.25%	0.27%	$4,421
18	Jun-2019	May-2019	$113,928,017	17.25%	0.27%	$4,422
19	Jul-2019	Jun-2019	$113,947,385	17.25%	0.27%	$4,423
20	Aug-2019	Jul-2019	$113,971,509	16.63%	0.27%	$4,265
21	Sep-2019	Aug-2019	$113,981,288	16.56%	0.27%	$4,247
22	Oct-2019	Sep-2019	$113,995,356	16.56%	0.27%	$4,248
23	Nov-2019	Oct-2019	$114,103,482	16.56%	0.27%	$4,252
24	Dec-2019	Nov-2019	$114,122,449	16.56%	0.27%	$4,253
25	Jan-2020	Dec-2019	$114,160,806	16.63%	0.27%	$4,273
26	Total (Sum Lines 14 thru 25)					$52,034
27	**Total BITS Surcharge billed by New England Power Company (Line 13 + Line 26)**					**$19,213,376**

Notes

(a) "Billing Month" represents the month the bill was issued, while "Service Month" represents the month for which billing of the BITS surcharge was calculated for.

(b) NECO's Primary Distribution System Carrying Charge. For service month's January through June, the 2017 carrying charge was used due to availability of data. July and December used the updated 2018 carrying charge. August through November was billed using an incorrect carrying charge. The billed amounts are subject to true-up based on 2019 data.

(c) Share % is calculated according to local service agreements TSA-NEP-83 and TSA-NEP-86, which contain the calculation of the BITS Surcharge. The data used is based on 2018 data and is subject to true-up based on 2019 data.

PUC 3-5

Request:

Please re-calculate the 2019 revenue requirement for the BITS project consistent with the requirements of Schedule 21-NEP, but calculate it in the same manner that the revenue requirement is calculated for transmission facilities in Rhode Island providing local network service, instead of treating the BITS facilities as distribution facilities used for transmission. Provide all relevant schedules showing the calculation, including without limitation schedules similar to Attachment PUC 2-5, the chart on page 4 of PUC 1-2, and Attachment PUC 2-2.

Response:

Please refer to Attachment PUC 3-5-1 which provides a hypothetical 2019 revenue requirement for the BITS project calculated using the formula applicable to transmission facilities in Rhode Island providing local network service under Schedule 21 - NEP. However, note that in order to provide a response to this data request, the calculation uses New England Power Company's Average Annual Transmission Carrying Charge as per Attachment DAF to Schedule 21 – NEP. While the Company has applied this carrying charge in responding to PUC 3-5 in order to be responsive to the Commission's request, this approach is not practical. The application of NEP's carrying charge to a NECO owned asset, even hypothetically, does not provide an accurate comparison for review of the existing calculation of the BITS surcharge.

Additionally, there is no formula for calculating a transmission carrying charge specific to NECO in Schedule 21-NEP or in NEP's Tariff No.1. The Company has however calculated a hypothetical NECO transmission carrying charge for use in the direct charging of assets such as the BITS project. Please refer to Attachment PUC 3-5-2 which provides a re-calculated hypothetical 2019 revenue requirement for the BITS project using a hypothetical NECO transmission carrying charge based on its 2019 Integrated Facilities Agreement "IFA" transmission revenue requirements.

Prepared by or under the supervision: Michael Artuso

The Narragansett Electric Company
Integrated Facilities Agreement
Summary of BITS Surcharge
For Costs in Calendar Year 2019

Line	Month	Gross Plant	Carrying Charge (a)	BITS Surcharge (b)
1	January	113,500,009	13.91%	1,315,552
2	February	113,523,131	13.91%	1,315,820
3	March	113,855,096	13.91%	1,319,668
4	April	113,912,570	13.91%	1,320,334
5	May	113,928,017	13.91%	1,320,513
6	June	113,947,385	13.91%	1,320,738
7	July	113,971,509	13.91%	1,321,017
8	August	113,981,288	13.91%	1,321,131
9	September	113,995,356	13.91%	1,321,294
10	October	114,103,482	13.91%	1,322,547
11	November	114,122,449	13.91%	1,322,767
12	December	114,160,806	13.91%	1,323,211
13	**Total Calendar Year 2019**			**15,844,593**

Notes

(a) The Narragansett Electric Company's 2019 carrying charge calculated using transmission revenue requirements as per annual IFA filing

(b) As per PUC 3-5, the calendar year 2019 BITS Surcharge is recalculated using a hypothetical Narragansett Electric Company transmission carrying charge as opposed to the FERC approved Primary Distribution System Carrying Charge set forth in Schedule III-B to NEP's FERC Electric Tariff No. 1

Narragansett Electric Company
Integrated Facilities Agreement
Annual True-up
CY 2019

Line No.	Transmission Investment Base:	(A) 1st Quarter FF1 CY 2019	(B) 2nd Quarter FF1 CY 2019	(C) 3rd Quarter FF1 CY 2019	(D) 4th Quarter FF1 CY 2019	(E) [Col (A) + (B) + (C) +(D)]/4 Annual FERC Form 1 Revenue Requirement	(F) [Page 2, Col. D] CY 2019 Actual Monthly Billing	(G) Reconciliation (Over)/Under	Tariff Reference	
1	Transmission Plant	$894,777,746	$908,050,705	$921,978,153	$927,077,457	$912,971,015	$914,379,347	($1,408,332)	Section III-B (B) (A) (1) (a)	Total Transmission Investment Base shall be defined as a
2	Transmission General Plant	$6,483,596	$6,526,534	$6,559,952	$6,637,875	$6,551,989	$5,102,869	$1,449,121		Transmission Plant, plus (b) Transmission Related General Plant
3	Transmission Plant Held for Future Use	$12,532,019	$12,532,019	$12,532,019	$12,532,019	$12,532,019	$12,531,980	$39		plus (c) Transmission Land Held for Future Use, plus (d)
4	NEEWS-Related CWIP	$0	$0	$0	$0	$0	$0	$0		Transmission Related Construction Work In Progress, less (e
5	Sub-Total Transmission Plant	$913,793,360	$927,109,257	$941,070,124	$946,247,351	$932,055,023	$932,014,196	$40,827		Transmission Related Depreciation Reserve, less (f) Transmissio
6										Related Accumulated Deferred Taxes, plus (g) Transmission
7	Transmission Depreciation Reserve	($125,214,347)	($128,212,841)	($132,590,277)	($136,322,738)	($130,585,051)	($130,988,401)	$403,350		Related Loss on Reacquired Debt, plus (h) Transmission
8	Transmission Accumulated Deferred Taxes	($140,017,869)	($140,691,316)	($139,915,390)	($138,533,254)	($139,789,457)	($146,256,823)	$6,467,366		Prepayments, plus (i) Transmission Materials and Supplies, plus (j
9	Transmission Loss on Reacquired Debt	$863,052	$844,722	$829,141	$810,565	$836,870	$837,403	($533)		Transmission Related Cash Working Capital
10	Transmission Prepayments	$1,084,834	$1,685,395	$1,116,190	$509,697	$1,099,029	$1,124,948	($25,919)	Section III-B (B) (L) (1)	The Annual True-up will reconcile any differences between a
11	Transmission Materials & Supplies	$2,949,928	$2,994,625	$2,933,793	$2,865,867	$2,936,053	$2,946,906	($10,853)		recalculation of the costs for the Service Year based on actual data
12	Transmission Cash Working Capital	$3,116,316	$3,116,316	$3,116,316	$3,116,316	$3,116,316	$2,912,027	$204,289		reported in Customer's Quarterly FERC Form l's as compared to the
13	**Total Transmission Investment Base**	**$656,575,276**	**$666,846,158**	**$676,559,897**	**$678,693,805**	**$669,668,784**	**$662,590,257**	**$7,078,527**		monthly actual costs invoiced. The recalculation of the costs for th
14										Service Year will be done using the average quarterly balances for al
15	Average Return and Associated Income Taxes (%)	9.632%	9.604%	9.629%	9.645%	9.656%				balance sheet items used in the formula (i.e. Plant, Depreciation Reserve
16										Deferred Taxes). Expenses will be those Service Year expenses reported
17	**Transmission Revenue Requirement:**					CY2019 Actual				in Customer's 4th Quarter FERC Form 1.
18	Return and Associated Income Taxes	$63,483,080	$64,248,210	$65,314,994	$65,617,475	$64,665,940	$64,272,167	$393,772		
19	Transmission Depreciation & Amortization Expense					$20,590,467	$20,555,897	$34,570	Section III-B (B) (K)	Billing Adjustments shall be plus or minus any billing adjustments from the pric
20	Transmission Amortization of Loss on Reacquired Debt					$62,693	$62,909	($216)		transmission billing periods. Billing adjustments shall include, but not be limite
21	Transmission Amortization of Investment Tax Credit					($530)	($533)	$3		to, adjustments due to corrections to any value included in this formula, including
22	Transmission Municipal Tax Expense					$16,162,255	$16,162,255	$0		but not limited to, corrections to the FERC Form 1.
23	Payroll Taxes					$573,072	$582,961	($9,889)		
24	Transmission Operation and Maintenance Expense					$9,805,203	$21,887,673	($12,082,470)	Section III-B (B) (I)	Direct Assignment Facilities Credit shall equal the monthly revenue received b
25	Transmission Administrative and General Expense					$15,125,328	$1,408,545	$13,716,784		NEP for service provided to any of NEP's wholesale customers that utilize
26	Direct Assignment Facilities Credit - Attachment 6I					$1,606,304	$1,606,304	$0		directly assigned transmission, distribution and/or generator interconnectio
27	Integrated Facilities Credit - BITS Surcharge					$18,948,602	$19,207,600	($258,998)		facilities owned by Customer. Such NEP revenue is defined as any revenue NEP
28	Billing Adjustment					$0	($1,345,858)	$1,345,858		receives for Direct Assignment Facilities under the ISO-NE OATT or any
29	Billing Adjustment Prior Year True-up					($2,157,412)	($2,157,412)	$0		interconnection-related charges for Customer-owned and/or maintained facilitie
30	**Total Transmission Revenue Requirement**					**$145,381,922**	**$142,242,508**	**$3,139,415**		under FERC jurisdictional agreements where NEP is the party to the agreement
31										
32	**Interest- Attachment 3**				Revenue Requirement	$126,984,428		**$76,116**	Section III-B (B) (L) (1)	The Annual True-up Adjustment will
33					Transmission Plant	$912,971,015			Section III-B (B) (L) (3)	be adjusted for interest, whether positive or negative, accrued monthly
34	**Total CY19 True Up with Interest - Attachment 3**							**$3,215,531**		from December 31 of the Service Year to the end of the calendar month in
					Carrying Charge	**13.91%**				which the Annual True-up Adjustment will be applied to a monthly
										billing. Interest shall accrue pursuant to the rate specified in th
										Commission's regulations 18 C.F.R §35.19a.

PUC 3-6

Request:

Referring to the response to PUC 2-2(c), it states: "The Company . . . applied the allocated cost of service to the amount of actual BITS surcharge billings to NEP in calendar year 2019 to determine the general cost components as shown on the Attachment." This appears to suggest that all of the cost components shown in Attachment PUC 2-2 page 1 and column 2 of the chart on page 4 of PUC 1-2 were not the actual costs incurred by the Company but are imputed using an allocation methodology. Please confirm whether this understanding is correct. If not, please explain.

Response:

Yes, this understanding is correct. All the cost components shown in Attachment PUC 2-2 page 1 and column 2 of the chart on page 4 of PUC 1-2 are imputed costs based on the proration of the cost of service allocation section of the annual distribution carrying charge calculation as shown on Pages 2 and 3 of Attachment PUC 2-2.

PUC 3-9

Request:

Referring to Attachment PUC 2-5, page 4, please confirm that the two key drivers that determine the annual amount of the BITS surcharge is not actual costs incurred by the Company, but rather, (i) the amount of gross plant of the BITS cable, and (2) the ratio of total distribution cost of service to total distribution plant. If so, please explain the ratemaking rationale for using a formula of this type for the BITS assets that does not rely on actual costs and how this results in a just and a reasonable rate that fairly compensates the utility.

Response:

The Company confirms that the BITS surcharge is calculated by multiplying the gross plant investment in the BITS cable project by the Primary Distribution System Carrying Charge, which is the ratio of Total Primary Distribution Revenue Requirement to Total Primary Distribution Plant as detailed in the section of Tariff No. 1, Schedule III-B titled "Calculation of Primary Distribution Revenue Requirements". This is the "filed rate" at FERC so the Company may not deviate from it.

The methodology of the calculation of the FERC-approved BITS Surcharge is indicative of average cost rate making. This method is often used because tracking and calculating actual costs of specific assets may prove to be administratively burdensome. By utilizing a carrying charge approach, an estimate of the average cost of service for each dollar of plant in service is calculated and applied to the gross plant investment of a facility to calculate the respective cost of service charged to the customer.

Since the cost inputs that go into the calculation of a carrying charge are indicative of all assets of a company, the imputed components of the carrying charge represent all vintages across old and new lives – in other words the average costs per year of an asset averaged over its useful life.

The formula rate application of a carrying charge to calculate the revenue requirement associated with facilities that are charged directly to specific customers is meant to appropriately compensate the utility over the life of the asset.

Prepared by or under the supervision: Michael Artuso

PUC 3-12

Request:

Rhode Island General Laws 39-26.1-7(f) specifies the following for the Block Island cable cost recovery: "The revenue requirement for the annual cable costs shall be calculated in the same manner that the revenue requirement is calculated for other transmission facilities in Rhode Island for local network service under the jurisdiction of the federal energy regulatory commission." (emphasis added)

a. Please explain all of the reasons why the Company has been calculating the revenue requirement for the BITS assets using the formula applicable to "Customer-owned distribution facilities utilized for purposes of providing wholesale transmission service," instead of "transmission facilities," as specified in the statute.

b. Please also explain why the Company has classified the BITS assets as "Customer-owned distribution facilities utilized for purposes of providing wholesale transmission service," instead of transmission facilities, when the Company represented to the Commission in Docket 4473 (Response to Division 1-13, sponsored by Bill Malee): "The BITS facilities will be categorized as 'transmission' and the associated costs recovered via FERC rates."

Response:

a. Calculation of the BITS Surcharge is detailed in Attachment 2 of the Local Service Agreements between: 1) New England Power Company, Block Island Power Company, and ISO New England, Inc. (TSA-NEP-83, see Attachment PUC 3-3-5) and 2) New England Power Company, The Narragansett Electric Company, and ISO New England, Inc. (TSA-NEP-86, see Attachment PUC 3-3-6). Copies of these agreements can be found in the Company' response to PUC 3-3.

   Under the section titled "Calculation of BITS Surcharge" the classification of "Customer-owned distribution facilities" has been bolded for emphasis:

   "The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

   The IFA Facilities Credit shall equal the monthly integrated facilities credit for **Customer-owned distribution facilities** received by the Transmission Customer for the BITS facilities pursuant to Schedule Ill-B of New England Power Company's FERC

PUC 3-12, page 2

Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year."

b. In the response to Division 1-13 in Docket No. 4473, the classification as transmission was used to reflect that that costs would be recovered through FERC approved transmission formula rates of the BITS Surcharge as detailed in TSA-NEP-83 and TSA-NEP-86 and Direct Assignment Facilities Credit of Schedule III-B which is the IFA revenue requirement billed to NEP.

Prepared by or under the supervision: Michael Artuso

PUC 3-13

Request:

Is the Company aware of any communications with Rhode Island regulatory authorities prior to 2020 where the Company specifically disclosed the fact that it would be classifying the BITS assets as distribution facilities used for transmission instead of transmission? If so, please identify and describe.

Response:

The Company is not aware of any specific communications with Rhode Island regulatory authorities prior to 2020 where the Company discussed the classification of the BITS assets. However, the asset classification used to describe the BITS facilities as distribution is contained in the service agreements filed and approved by FERC in 2014 and 2015, copies of which were served on the Rhode Division of Public Utilities and Carriers and the Rhode Island Public Utilities Commission.

Specifically, in the Local Service Agreement ("LSA") among New England Power ("NEP"), Block Island Power Company ("BIPCO"), and ISO New England Inc. ("ISO-NE"), designated as the First Revised Service Agreement No. TSA-NEP-83 under the ISO-NE OATT and the LSA among NEP, The Narragansett Electric Company ("Narragansett"), and ISO-NE, designated as First Revised Service Agreement No. TSA-NEP-86 under the ISO-NE OATT, the section entitled, "Calculation of BITS Surcharge" (See the Company's response to PUC 3-3 and specifically Attachments PUC 3-3-5 and PUC 3-3-6 for a copy of the LSAs) states,

> The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:
>
> I. The IFA Facilities Credit shall equal the monthly integrated facilities credit for **Customer-owned distribution facilities** received by the Transmission Customer for the BITS facilities pursuant to Schedule 111-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. I, on or about the June billing month of each year. (Emphasis added.)

In the section of First Revised Service Agreement No. TSA-86 entitled, "Description of the Block Island Transmission System", the BITS facilities are described as 34.5kV facilities, which are typically distribution facilities based on the voltage/type.

Prepared by or under the supervision: Michael V. Artuso and Legal Department

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PUC 3-15

Request:

Referring to the Company's filing in Docket 5005, Schedule MVA-6, line 1, which provides "NEP's Schedule 21 Non-PTF Revenue Requirement" of $128,634,074, please provide a schedule that separates the portion of the revenue requirement that is derived from distribution facilities used for transmission (if any) from the portion of the revenue requirement derived from transmission facilities. Please also provide a further breakdown of facilities (if any) that were below the voltage level ordinarily used for a transmission classification, but were nevertheless treated as "transmission facilities" in the revenue requirement.

Response:

Please see Attachment PUC 3-15-1 which details the separation of distribution facilities from $128,634,074 found in Docket No. 5005, Schedule MVA-6, Line 1.

Please see Attachment PUC 3-15-2 which provides a further breakdown of facilities with voltage levels 34.5kV or below that are classified and treated as transmission facilities in the revenue requirement. These assets are considered exceptions to the Company's classification of assets guidelines using voltage attributes primarily due to legacy classifications. This exception is applied to facilities designed and constructed a very long time ago and the desgination as transmission was retained even if the assets were replaced on a one-for-one or functional basis. Only in the event of a system re-configuration which results in a functional re-classification would the project be submitted for a change in classification through the Company's project approval and sanctioning process.

Prepared by or under the supervision: Michael Artuso

NEP's Schedule 21 Non-PTF Revenue Requirement as per Docket 5005, Schedule MVA-6, Line 1
Attachment PUC 3-15

		(A) = (B) + (C)	(B)	(C)	(D)	(E)
Line	Month	LNS Transmission Revenue Requirement	NEP-specific Revenue Requirement (a)	IFA Transmission related Integrated Facilities Credit	Revenue requirement that is derived from distribution facilities	Revenue requirement that is derived from transmission facilities
1	Jan-2019	13,755,401	424,695	13,330,706	1,696,758	11,633,947
2	Feb-2019	6,864,143	(6,852,007)	13,716,150	1,727,685	11,988,465
3	Mar-2019	10,277,037	(3,834,521)	14,111,558	1,723,678	12,387,880
4	Apr-2019	12,456,550	(664,168)	13,120,719	1,754,401	11,366,318
5	May-2019	15,755,837	1,697,347	14,058,490	1,727,437	12,331,053
6	Jun-2019	17,258,391	5,055,948	12,202,443	1,729,552	10,472,891
7	Jul-2019	8,345,073	(3,906,988)	12,252,061	1,729,887	10,522,174
8	Aug-2019	3,403,821	(10,479,361)	13,883,182	1,554,721	12,328,462
9	Sep-2019	2,702,781	(10,415,607)	13,118,387	1,657,976	11,460,412
10	Oct-2019	11,830,804	(1,999,026)	13,829,830	1,665,088	12,164,742
11	Nov-2019	12,141,494	(1,320,545)	13,462,039	1,667,879	11,794,160
12	Dec-2019	13,842,743	(465,815)	14,308,559	1,666,905	12,641,654
13	**Total**	**128,634,074**	**(32,760,049)**	**161,394,124**	**20,301,968**	**141,092,156**

Notes

(a) NEP's revenue requirement includes revenue credits associated with revneues received through ISO-NE Regional Network Service

Transmission Facilities 34.5KV or Less

Company	Major Location Description	Amount as of 12/31/2019
NECO	WASHINGTON SUB 13.8KV TRANS Total	866,784.72
NECO	STAPLES SUB TRANS 13.8KV -- PTF Total	1,408,900.88
NECO	PAWTUCKET #1, PAWTUCKET TRAN 13.8KV Total	5,397,846.17
NECO	VALLEY SUB 13.8KV TRANS Total	2,863,065.02
NECO	RIVERSIDE SUB TRAN 13.8KV -- PTF Total	7,812,916.89
NECO	3304 34.5KV DRUMROCK SUB. WRK - WES Total	283,480.56
NECO	3306 34.5KV -W.KINGSTON-KENYON-WOOD Total	252,407.12
NECO	33046 34.5KV WESTLY SUB WES-STRCTRE Total	76,331.19
NECO	3312 34.5KV KENT CNTY SUB-DIV ST-WI Total	176,529.44
NECO	33204 34.5KV UG FR DQ SUB PRV-WELLI Total	85,377.65
NECO	3308 34.5KV W.KINGS. SUB-KINGS. & W Total	5,143,002.13
NECO	CLP 57 34.5KV WESTERLY SUB-CT/R.I.L Total	969.10
NECO	3310 34.5KV KENT CTY SUB-3304 U.S N Total	651,075.15
NECO	3305 34.5KV W.KINGSTON-KENYON-WOOD Total	438,443.67
NECO	3311 34.5KV KENT CTY-DIV.ST.-LAFAYE Total	330,921.54
NECO	3307 LINE 34.5KV W.KINGS-WAKEFIELD Total	355,878.19
NECO	33A LINE QUONSET POINT 34.5KV Total	55,642.99
NECO	33C LINE QUONSET POINT 34.5KV Total	11,700.11
NEP	66J HRRMN-SADAWGA-JCKSNVLL 6.9KV VT Total	139,486.30
NEP	1-2 LN CLINTON-FAIRMONT 13.8KV Total	57,782.81
NEP	3318 LINE-34.5 KV CMF/MCN-TRANSM-NH Total	1,302,750.67
NEP	128/2132/2134 23LV REVERE-CHELSEA Total	32,662.45
NEP	1302 LN WILDER-GREEN MT PWR 13.8KV Total	19,073.91
NEP	V303-1304 LN WLDR-GRAN ST(NH)13.8KV Total	6,001.62
NEP	V303-1304 LN WLDR-GRAN ST(VT)13.8KV Total	66,331.99
NEP	2377 LN 23KV GROVELAND-W AMESBURY Total	250,028.30
NEP	3315 34.5KV COMERFORD-LITTLETON(NH) Total	8,187,258.08
NEP	3315 34.5KV COMERFORD-LITTLETON(VT) Total	2,120,851.41
NEP	3314 TAP 34.5KV GILMAN (NH) Total	350,124.15
NEP	3314 TAP 34.5KV GILMAN (VT) Total	1,874,741.76
NEP	2388 LN SANDY POND-WESTFORD 23KV Total	289,923.34
NEP	2396 KING ST GRVLND-W AMSBY 23KV Total	3,301,099.16
NEP	2278LN CHARTLEY-NORTON TWN LN 23KV Total	80,576.48
NEP	3318 TAP TO SUB#15 MONROE-NH 34.5KV Total	3,616.55
NEP	3386 LN 34.5KV COMRFD-MNROE(NH)PTF Total	9,856.82
NEP	231-232 STA SRV FDRS 23 KV SANDY Total	4,759.73
NEP	2301 & 2302 LINES 23KV TAP Total	56,049.64

PUC 3-21

Request:

Please explain how actual Administrative & General expenses (if any) incurred from the operation and maintenance of the BITS project are assessed and/or allocated to the Company. Please provide a schedule for each year since the Company began billing NEP for the BITS project, showing how the actual Administrative & General expenses (if any) were derived and charged to the Company as a result of the operation and maintenance of the BITS project.

Response:

Administrative & General expenses are recorded through allocations and direct charges. Direct charges are expensed by project and are shown in the table below. Allocated A&G expenses are difficult to identify as they are allocated at the service company level to the appropriate operating companies but are not broken out by facility.

Please see the below schedule for actual direct Administrative & General expenses which were charged due to the BITS project. The miscellaneous expenses were majorily driven by a combination of contractor, fleet and union expenses.

Administrative and General Expense		
Calendar Year	Expense Details	Amount
2016	Miscellaneous General Expenses	5,134
2017	Miscellaneous General Expenses	7,630
2018		-
2019		-

PUC 3-22

Request:

Please provide a schedule for each year since the Company began billing NEP for the BITS project, showing the components of the actual transmission operation and maintenance expenses (if any) incurred by the Company for operating and maintaining the BITS assets.

Response:

Please see the below schedule for actual Operation and Maintenance expenses in relation to the BITS project, which were charged to the Company.

Operation and Maintenance Expense (dollars)		
Calendar Year	Expense Details	Amount
2016	Overhead Line and Operation Supervision/Engineer Expense	128
2017	Operation Supervision/Engineer Expense	1,480
2018	Anchor Zone Maintenance	189,702
2019	Cable Sand Dumping	114,936

PUC 3-23

Request:

Referring to Attachment PUC 2-5, page 2 of 4, please explain why the total plant in service subject to the surcharge increased by approximately $1 million over the course of 2019.

Response:

Total plant in service subject to the surcharge increased by approximately $1 million in calendar year 2019 due to a combination of internal, consultant and contractor work being done on the cable. Please see the below tables for details regarding this increase.

Internal Info	**Details**	**Amount**
National Grid	Internal Labor to Support Capital Activity	$ 105,884
	Total Labor Charges	**$ 105,884**

Contractor Info	**Description of Work Completed**	**Amount**
LS Cable America	Partial Retainage payment	$ 290,965
LS Cable America	2nd Tekduct Installation cancellation (cable protection)	$ 277,553
	Total Contractor Charges	**$ 568,518**

Consultant Info	**Details**	**Amount**
Power Engineers Consulting	Cable surveys, Environmental reports for Agencies (CRMC, BOEM)	$ 250,988
Public Archaeology Lab.	Environmental surveys and reports	$ 28,554
Hinckley Allen & Snyder LLP	Legal Environmental Services	$ 28,052
Calibre System	Studies and reports for BOEM	$ 19,051
	Total Consultant Charges	**$ 326,645**

Prepared by or under the supervision: Michael Artuso

PUC 3-24

Request:

Referring to PUC 1-2, the Company provides an estimate of annual "routine inspection and maintenance as well as possible repair costs" itemized in a chart, totaling between $93,200 to $389,200 per year. Yet, the BITS formula rate calculates an annual imputed operations and maintenance cost allowance of approximately $3 million, along with an annual Administrative and General expense of approximately $6 million. The Company's response (page 5) also states: "the Company did not actually incur $9.1 million to operate and maintain the BITS assets in CY 2019 and would not expect to incur annual operating and maintenance costs at such a level until a significant repair to the BITS cable is warranted."

a. Does the Company agree that the BITS formula rate substantially overcompensated the Company for its ownership, operation, and maintenance of the BITS cable in 2019 because the amount of revenue being obtained under the formula far exceeded actual cost incurrence? If not, please explain why not.

b. Given how the BITS formula rate operates, is it the Company's expectation that the actual combined A&G and O&M costs are reasonably likely to be equal to or greater than the combined imputed A&G and O&M expenses at any time in the foreseeable future? If so, when? If not, why not?

Response:

a. The Company calculated the BITS surcharge, inclusive of its return on the investment and reimbursement of operation and maintenance costs, in accordance with the FERC approved formula rate. The Company is not permitted to deviate from the FERC approved formula rate in calculating the BITS surcharge. The application of a carrying charge in the formula rate to calculate the revenue requirement associated with facilities that are charged directly to specific customers is not meant to result in overcompensation over the life of the asset. For Distribution ratemaking purposes subject to State jurisdiction, the assets and related revenues were removed from the revenue requirement and treated as stand-alone assets as opposed to reducing base distribution revenue requirements due to concerns about substantial increases in costs in later years and due to the fact the costs are being recovered through transmission rates.

b. The application of the carrying charge is meant to represent the average cost of service of an asset placed into service. Over the life of the asset it is expected that the revenue recovered through the application of the carrying charge is fairly in line with the actual

O&M and A&G costs incurred over the life of the asset. The Company is, however, unable to predict when certain substantial costs associated with the BITS facilities will occur in future years.

PUC 3-26

Request:

Referring to the response to PUC 2-2 (b), it states that "the $9.1 million is effectively prefunding future repairs on BITS assets." What does the Company mean by "pre-funding?" Please explain how the $9.1 million is pre-funding repairs. If the $9.1 million represents pre-funded repairs, how have the ratepayers benefitted from paying the Company $9.1 million in excess of actual cost incurrence for 2019 and another $8.9 million in 2018?

Response:

Please refer to the response to PUC 3-24 (b) that explains how the imputed O&M costs represent the average cost per year over the life of the asset. In earlier years of a project, actual costs may be lower compared to the imputed amounts. While during the later years of a project's life, along with any unexpected O&M costs during, actual costs may be greater than the imputed costs. With the average cost approach using carrying charges, it is expected that the revenue recovered through the application of the carrying charge is fairly in line with the actual O&M and A&G costs incurred over the life of the asset.

PUC 3-27

Request:

Please refer to the investor presentation materials found at the following link: https://investors.nationalgrid.com/~/media/Files/N/National-Grid-IR-V2/results-centre/2020/fy20-results-combined-presentations-with-appendices.pdf;

On page 45, there is a column in the chart labeled: "Narragansett Distribution Electric." The column identifies the "Rhode Island PUC" as the regulator, states the "allowed return" as 9.3%, and summarizes the earnings sharing mechanism that had been approved by the Commission in the Company's last rate case. However, the same column identifies the "achieved return" as 11.9%. Does the Company agree that the referenced document at page 45 of the publication conveys an understanding to the investment community that the 11.9% achieved return on equity was measuring Narragansett Electric's financial performance as it related entirely to the electric distribution business, expenses, earnings sharing rules, and revenues that were subject to PUC jurisdiction in 2019? If the Company disagrees, please explain.

Response:

The Company does not agree with this statement entirely; however, it does acknowledge that reference to the 11.9% in the chart on page 45 of the investor presentation materials could be read as to the Company's earnings for distribution rate-making purposes, which are subject to the PUC's jurisdiction. For external reporting purposes, the earnings results of The Narragansett Electric Company legal entity are reported in three categories: RI Electric, RI Gas and RI Transmission. The intent of including O&M in the RI Electric line item is to represent that RI Electric bears the ongoing O&M obligation in the future. The return on the BITS assets is represented for reporting purposes in the RI Transmission earnings. The Company believe its current approach is the most transparent representation because if all the revenues and costs were included in the RI Transmission reporting line it would not accurately reflect which segment, Electric, has the future obligation for O&M. Also, please see the Company's response to PUC 2-7 (a), (c), attached hereto as Attachment PUC 3-27, which reconciles the actual earnings of 9.12% in CY 2019 with the actual full-year results for fiscal year 2019/20 of 11.9% return on equity.

The Company will work with the external reporting teams to review the potential for a footnote or other clarification in future annual reports.

Prepared by or under the supervision: Christopher McCusker

Jennifer Brooks Hutchinson
Acting Assistant General Counsel and Director

September 2, 2020

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4770 – Electric Earnings Sharing Mechanism
Earnings Report - Twelve Months Ended December 31, 2019
Responses to PUC Data Request – Set 2

Dear Ms. Massaro:

On behalf of National Grid,[1] enclosed please find a copy of the Company's response to data requests PUC 2-7 in the above-referenced docket.[2]

The Company's responses to remaining data requests PUC 2-4 and PUC 2-6 are pending.

Thank you for your attention to this transmittal. If you have any questions regarding this filing, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Docket 4770 Service List
John Bell, Division
Christy Hetherington, Esq.
Leo Wold, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).
[2] Per practice during the COVID-19 emergency period, the Company is providing a PDF version of these responses. The Company will provide the Commission Clerk with a hard copy and, if needed, additional hard copies of this transmittal at a later date.

280 Melrose Street, Providence, RI 02907
T: 401-784-7288 ■ jennifer.hutchinson@nationalgrid.com ■ www.nationalgrid.com

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PUC 2-7[1]

Request:

PUC 1-5 asked whether the Company's earnings were overstated in any publications to investors. The response states that "neither the Company nor any of its affiliates have over-reported earnings in any other public documents . . ." With reference to this response, please compare page 34 of National Grid plc's "2019/20 Full Year Results Statement," found at:

https://investors.nationalgrid.com/~/media/Files/N/National-Grid-IR-V2/results-centre/2020/results-statement-fy2019-20.pdf

a. The document represents that the Return on Equity for Narragansett Electric for fiscal year 2019/20 was 11.9%.
   i. Recognizing the differences between calendar and fiscal year reported earnings, please explain why the 2019 calendar year "Actual Earnings" stated in the revised earnings report is given as 9.12%, while the Full Year Results Statement states the return on equity for the distribution business for FY 2019/20 at a materially higher 11.9%.
   ii. Please provide an explanation and schedule that reconciles the difference between the two earnings numbers.
   iii. Please separately identify any difference between the calendar year-end reported earnings percentage and fiscal year-end reported earnings percentage that is **not** solely attributable to timing difference.

b. The document represents the Return on Equity for Narragansett Electric for fiscal year 2018/19 was 10.7%.
   i. Recognizing the differences between calendar and fiscal year reported earnings, please explain why the 2018 calendar year "Actual Earnings" stated in the revised earnings report is given as 6.14%, while the Full Year Results Statement states the return on equity for the distribution business for FY 2018/19 at a materially higher 10.7%.
   ii. Please provide an explanation and schedule that reconciles the difference between the two earnings numbers.
   iii. Please separately identify any difference between the calendar year-end reported earnings percentage and fiscal year-end reported earnings percentage that is **not** solely attributable to timing difference

[1] The Company's response begins on page 2.

Prepared by or under the supervision of: Melissa A. Little

PUC 2-7, page 2

c. If the Company's review of this document reveals that the earnings of Narragansett Electric's distribution business were incorrectly represented to investors on page 34, (i) please explain why the Company did not identify this document in its response to PUC 1-5 and (ii) please file a corrected response to PUC 1-5, answering the questions asked in PUC 1-5, with reference to the above cited document.

Response:

a & b. Please refer to Attachment PUC 2-7 which reconciles Actual Earnings in calendar years 2018 and 2019 to the fiscal year Full Year Results Statement in fiscal years 2019 and 2020. Reconciling items that are not solely attributable to timing differences in reporting periods are noted as "non-timing".

c. The Company's review of National Grid plc's "2019/20 Full Year Results Statement" and the reconciliation of earnings results presented at Attachment PUC 2-7 illustrates that the earnings of Narragansett Electric's distribution business were not incorrectly represented to investors.

The largest reconciling item between CY 2019 and FY 2020 earnings is net income related to BITS investments of $9.2 million which represents approximately 200 basis points of return on equity. The revenue requirement on BITS investments is ultimately recovered from Narragansett Electric's retail customers through FERC-regulated transmission rates, and therefore BITS-related net income is excluded from the calculation of RIPUC-regulated electric distribution earnings. However, for management reporting purposes, the portion of BITS-related net income attributable to the recovery of operating expenses is recorded as distribution earnings, as the Company considers BITS assets to be distribution assets based on its voltage of 34.5kV (distribution level voltage).

Likewise, net income on BITS investments is also a major reconciling item between CY 2018 and FY 2019, totaling $8.9 million and approximately 200 basis points of return on equity. CY 2018 also saw the commencement of the new rate plan under Docket 4770 effective September 1, 2018. Therefore, due to the timing difference in earnings reporting periods, FY 2019 earnings reflected seven months of new rates as compared to CY 2018 earnings which reflected only four months of new rates, resulting in $9.1 million in additional revenue in fiscal year 2019 compared to calendar year 2018 which represents approximately 250 basis points of return on equity.

Prepared by or under the supervision of: Melissa A. Little

THE NARRAGANSETT ELECTRIC COMPANY
Return on Electric Distribution Common Equity Reconciliation
Regulated Earnings for the twelve months ended Dec 31, 2018 and Dec 31, 2019 and
Financial Earnings for the twelve months ended Mar 31, 2018 and Mar 31, 2019

	Description	Reference	CY 2018/ FY 2019	CY 2019/ FY 2020	
			(a)	(b)	
	Earnings Reconciliation				
1	Base Earnings Available for Common per ESM at Dec 31		$18.1	$34.5	
2	Incentive revenue		$6.6	$6.4	
3	Income tax on incentive revenue		($1.4)	($1.3)	
4	Actual Earnings Available for Common per ESM at Dec 31	Sum of Line 1 through Line 3	$23.4	$39.6	
5					
6	Reconciling Items:				
7	Additional RDM Revenue included in Finance ROE Jan thru Mar		$9.1	$2.6	timing
8	Excess ADIT amortization excluded from Finance ROE		$3.3	$4.5	non-timing
9	Bad debt expense included in Finance ROE versus net write-offs included in ESM		($2.3)	($2.3)	non-timing
10	Net Income from BITS included in Finance ROE		$8.4	$9.2	non-timing
11	COVID related costs excluded from Finance ROE		$0.0	$0.7	non-timing
12	Company Share of Earned Savings included in ESM		$2.1	$0.0	non-timing
13	Variable pay excluded from ESM		($0.6)	($0.2)	non-timing
14	Sales expense excluded from ESM		($0.3)	($0.2)	non-timing
15	Additional Income Taxes Computed for Finance ROE		($4.3)	($5.0)	imputed/flowthrough
16	Difference on imputed Interest Expense		$2.3	$0.2	imputed/flowthrough
17	Other Differences due to different period coverage		$0.3	$1.5	timing
18	Earnings Available for Common per ROE at March 31	Sum of Line 4 through Line 17	$41.4	$50.7	
19					
20	**Rate Base Reconciliation**				
21	Rate Base at Dec 31 per ESM		$798.8	$881.6	
22	Reconciling Items:				
23	Net Plant Additions in 3 months (Jan-March)		$35.9	$36.0	timing
24	Difference on Prepaids and Inventory		($6.1)	$2.0	timing
25	Difference on Commondity CWC		$0.2	($1.2)	timing
26	Difference on ADIT (due to BITS)		($49.4)	($21.8)	non-timing (BITS); timing (all other)
27	Difference on Customer Deposit & Unamortized items		$0.1	($2.4)	timing
28					
29	Rate Base at March 31 per ROE	Sum of Line 21 through Line 27	$779.4	$894.1	
30					
31	**Average Rate Base**				
32	Per ESM (five-quarter average)	Per ESM	$747.8	$850.9	
33	Per ROE (year over year average)	Average of Line 29	$758.0	$836.8	
34					
35	**Average Equity Rate Base**				
36	Per ESM	Line 32 * 50.95%	$381.0	$433.5	
37	Per ROE	Line 33 * 51%	$386.6	$426.8	
38					
39	**Return (Actual Earnings)**				
40	Per ESM	Line 4 ÷ Line 36	6.14%	9.12%	
41	Per ROE	Line 18 ÷ Line 37	10.7%	11.9%	

Notes
ESM = CY 2019/CY 2018 annual distribution earnings report to RIPUC
ROE = earnings reported in FY 2019/ FY 2020 NG plc Annual Report

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

__________________________________ August 24, 2020
Joanne M. Scanlon Date

National Grid Docket No. 4770 (Rate Application) & Docket No. 4780 (PST)
Combined Service list updated 7/20/2020

Docket No. 4770 Name/Address	**E-mail Distribution List**	**Phone**
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PUC 3-28

Request:

What was the total remuneration incentive that the Company received from the payments made to Deepwater Wind from the production from the Block Island wind farm in 2019?

Response:

Pursuant to the Company's Long Term Contracting for Renewable Energy Recovery Reconciliation Provision, R.I.P.U.C. No. 2175, Contract Remuneration is defined as "the annual compensation as authorized by § 39-26.1-4, which shall be equal to two and three quarter percent (2.75%) of the actual annual payments made under the Long Term Contracts and Distributed Generation Standard Contracts for those projects that are commercially operating."

In Calendar Year ("CY") 2019, the Company incurred a Total Contract Cost associated with generation from Deepwater Wind of $29,006,937. Therefore, the remuneration earned on the Deepwater Wind Total Contract Cost in CY 2019 is $797,691 (2.75% x $29,006,937).

Prepared by or under the supervision: Adam S. Crary