Raquel J. Webster
Senior Counsel

February 25, 2021

BY ELECTRONIC MAIL

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

RE: Docket 5099 - Proposed FY 2022 Gas Infrastructure, Safety, and Reliability Plan
<u>Responses to PUC Data Requests – Set 6 (Entire Set)</u>

Dear Ms. Massaro:

I have enclosed an electronic version of National Grid's[1] responses to the Rhode Island Public Utilities Commission's ("PUC") Sixth Set of Data Requests in the above-referenced matter.

Please note that the Company already filed many of these responses with the PUC in a prior batch. However, since the Company filed these responses on a rolling basis, the Company is providing this copy of its responses to PUC Set 6 in sequential order per the PUC's request.[2]

Pursuant to 810-RICR-00-00-1.3(H)(3) and R.I. Gen. Laws § 38-2-2(4)(B), the Company respectfully requests that the Commission treat Attachments 1 through 6 to PUC 6-20 as confidential. In support of this request, the Company has enclosed a Motion for Confidential Treatment. In accordance with 810-RICR-00-00-1.3(H)(2), the Company also respectfully requests that the Commission make a preliminary finding that Attachments 1 through 6 to PUC 6-20 are exempt from the mandatory public disclosure requirements of the Rhode Island Access to Public Records Act.

Thank you for your attention to this matter. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosures
cc: Docket 5099 Service List
Leo Wold, Esq.
Al Mancini, Division
John Bell, Division
Rod Walker, Division

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[1] The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company").
[2] In addition, the Company will deliver six Bates stamped hard copies of PUC Set 6 to the PUC.

40 Sylvan Road, Waltham, MA 02451
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STATE OF RHODE ISLAND

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Fiscal Year 2022 Gas Infrastructure, Safety, and Reliability Plan	))))	Docket No. 5099

NATIONAL GRID'S MOTION FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] respectfully requests that the Rhode Island Public Utilities Commission ("PUC") grant protection from public disclosure certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 810-RICR-00-00-1-1.3(H)(3) ("Rule 1.3(H")) and R.I. Gen. Laws § 38-2-2(4)(B). National Grid also requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

On February 25, 2021, National Grid filed its responses to certain requests in the PUC's Sixth Set of Data Requests in this docket. In Data Request PUC 6-20, the Company includes co nfidential pricing information relating to the prices various vendors offered to the Company for gas meters. For the reasons described below, the Company requests that, pursuant to R.I. Gen. Laws § 38-2-2(4)(B) and Rule 1.3(H), the PUC afford confidential treatment to the confidential and proprietary information included in its response to Data Request PUC 6-20.

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

II. LEGAL STANDARD

Rule 1.3(H) of the PUC's Rules of Practice and Procedure provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I. Gen. Laws § 38-2-1, *et seq*. Under the APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information would be likely to either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. *Providence Journal Company v. Convention Center Authority*, 774 A.2d 40 (R.I. 2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. *Providence Journal*, 774 A.2d at 47. National Grid meets the first and second prongs of this test, which apply here.

III. BASIS FOR CONFIDENTIALITY

The pricing information included in the Company's response to Data Request PUC 6-20 is commercially sensitive financial information of the type that National Grid would not ordinarily make public. If National Grid were to allow the subject information to become public, it reasonably expects that the vendors whose gas meter pricing information is contained in the response to PUC 6-20 would be unwilling to offer National Grid any favorable pricing terms in the future out of concern that their negotiating position with customers would be compromised. Ultimately, public disclosure of such confidential pricing information could impair National Grid's ability to obtain advantageous pricing harming not only National Grid, but also its customers and vendors. Accordingly, National Grid is providing the information on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to the pricing information that is redacted in the public version of its response to Data Request PUC 6-20.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant this Motion for Protective Treatment of Confidential Information.

[SIGNATURE ON NEXT PAGE]

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
By its attorney,

____
Raquel J. Webster, Esq. (#9064)
National Grid
40 Sylvan Road
Waltham, MA 02451
781-907-2121

Dated: February 25, 2021

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.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

February 25, 2021
Date

Docket No. 5099- National Grid's FY 2022 Gas Infrastructure, Safety and Reliability (ISR) Plan - Service List 1/7/2021

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Conservation Law Foundation James Crowley, Esq. Conservation Law Foundation 235 Promenade St. Suite 560, Mailbox 28 Providence, RI 02908	jcrowley@clf.org;	401-228-1904

PUC 6-1

Request:

Referring to the response to PUC 2-1 which was provided in the Electric ISR, Docket 5098, (a) why does the Company calculate the revenue requirement differently for the Gas ISR than it calculates the revenue requirement for the Electric ISR, given that the ISRs arise out of the same statutory provision in Title 39? Please provide a full explanation. Please include a justification for the inconsistent treatment as a matter of ratemaking policy. (b) What impact, if any, would it have on Gas distribution capital planning, if the Commission required the Company to calculate the revenue requirement in the Gas IRS the same way as it calculates the revenue requirement for the Electric ISR?

Response:

(a) As indicated in the Company's response to PUC 5-1, the inclusion of Construction Work in Progress ("CWIP") in rate base was first approved in Docket RIPUC No. 3401 in 2002 and has subsequently been approved as a component of rate base in Docket Nos. 3943, 4323 and 4770. The Company's Gas ISR tariff has followed the same precedent since its inception in FY 2012. The basis of the difference in ratemaking between the Company's Gas and Electric businesses is the nature of the investment and the period of time between when construction commences and when construction concludes. As stated in the Company's response to PUC 5-8, the rationale for this historical treatment to recover capital-related spending rather than plant-in-service amounts is because the vast majority of investments included in the Company's annual Gas ISR filings are for projects started and completed during the fiscal year, with few projects extending over multi-year periods. The same cannot be said for Electric investment, where it is common for project construction to extend over multiple years. Therefore, precedent for the Company's Electric business is that investment is included as a component of rate base for recovery when that investment is deemed to be placed into service.

    R.I. Gen. Laws § 39-1-27.7.1 requires the Company to file an annual ISR plan with the Division and Commission for review, but does not include any direction regarding the ISR revenue requirement calculations. Instead, the details of the calculation of the revenue requirement is documented in the Company's ISR tariffs. The Company, therefore, calculates its Gas and Electric ISR revenue requirements in compliance with its approved ISR tariffs for its Gas and Electric businesses and per the ratemaking precedent currently in effect under each business' respective rate plan.

Prepared by or under the supervision of: Melissa Little and Amy Smith

PUC 6-1, page 2

(b) The Company would not change its capital planning process if the Commission required the Company to calculate the revenue requirement in the Gas ISR the same way it calculates the revenue requirement for the Electric ISR. The Company's capital planning process for the Gas ISR is a risk-based approach designed to ensure the safety and reliability of the gas system and is not impacted by revenue requirement calculations.

Prepared by or under the supervision of: Melissa Little and Amy Smith

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PUC 6-2

Request:

If the response to PUC 5-1 does not already do so, please recalculate the Gas ISR revenue requirement for FY 2022 in the same way that the Company calculates the Electric ISR and provide schedules showing the recalculation.

Response:

The recalculation of Gas ISR revenue requirement for FY 2022 based on a forecast of FY 2022 plant to be placed into service is provided in the Company's response to PUC 5-1, subpart (c).

Prepared by or under the supervision of: Melissa Little

PUC 6-3

Request:

Referring to the response to PUC 2-2(d), page 35 of 164, please confirm that the referenced accounting requirements do not allow for the accrual of CWIP until construction has started. Please also confirm that the referenced accounting requirements do not permit Preliminary Survey and Investigation charges to be included in CWIP until construction has started.

Response:

Construction Work in Progress ("CWIP") charges are only accrued once the Construction phase of the job has started. Please note that the FERC Chart of Accounts part 3, section 13, defines Components of Construction costs to include amounts paid to other companies, firms or individuals engaged by the utility to plan, design, prepare estimates, supervise, inspect or give general advice and assistance in connection with construction work. Also, please see the Company's response to PUC 2-2 (d) Attachment 1 – Work Order Life Cycle Playbook, page 46 of 174.

Costs charged to Account 183, Preliminary Survey and Investigation are excluded from CWIP until those charges are moved to Account 107, Construction Work in Progress. The Company has not historically used Preliminary Survey and Investigation ("PS&I") accounting for the Gas business since almost all Gas projects have a short life cycle and are completed in the year in which they begin.

Prepared by or under the supervision of: Andrey Androshchuk

PUC 6-4

Request:

Referring to the response to PUC 2-2(d), page 19 of 174, there is a reference to an "AFUDC Policy." Please provide a copy of the policy.

Response:

Please see Attachment PUC 6-4 for a copy of National Grid's U.S. accounting policy on the Allowance for Funds Used During Construction ("AFUDC").

Prepared by or under the supervision of: Melissa Little

nationalgrid THE POWER OF ACTION	US ACCOUNTING POLICY
Accounting for Allowance for Funds Used During Construction (AFUDC)	

TABLE OF CONTENTS

Section I: Purpose & Scope

National Grid USA (NGUSA or Company) is a public utility holding company with regulated subsidiaries engaged in the generation of electricity and the transmission, distribution and sale of both natural gas and electricity. NGUSA is an indirect, wholly-owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales.

Most of the Company's operations are conducted through its regulated utility subsidiaries. In addition, the Company has certain unregulated subsidiaries that provide energy related services to LIPA and other customers.

Constructing utility plant takes time, potentially resulting in the incurrence of significant carrying costs in advance of when the assets are ready for use and included in allowable costs for ratemaking purposes. Normally a regulated utility does not earn a return on assets under construction to cover financing costs incurred during the construction period. Therefore, regulators allow utilities to capitalize an allowance for funds used during construction (AFUDC), during the construction phase of a capital project, for future recovery. Only those incurred costs that are probable of recovery through future rates should be capitalized as part of utility plant (construction work in progress).

This document outlines National Grid's policy, procedures, and methodology for computing and capitalizing AFUDC. By adhering to these guidelines, we ensure the integrity, accuracy and validity of the AFUDC balance. This document also summarizes the underlying principles governing the accounting for this construction cost factor.

Section II: Policy

A. Definitions

The FERC Charts of account defines AFUDC, allowance for funds used during construction, as the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on the funds when so used, not to exceed without prior approval of the Commission allowances computed in accordance with the FERC formula, (see exhibit 1 in section IV).

B. Policy

The FERC guidelines under the Natural Gas Act, the Federal Power Act, Federal Power Commission (FPC) and Order No. 561 outlines the following requirements:

- Rates shall be calculated annually.
- The cost rate for common equity shall be the rate granted common equity in the last rate proceeding before the ratemaking body having primary rate jurisdiction. If such cost rate is not available, the average rate actually earned during the preceding three years should be used.
- The short-term debt balances and related cost and the average balance for construction work in progress shall be estimated for the current year with appropriate adjustments as actual data becomes available.
- The cost rates for long term debt and preferred stock are the weighted average cost.
- The balances for long-term debt, preferred stock, and common equity are the actual book balances as of the end of the prior year.
- Public utilities are required to monitor their actual experience and adjust to actual at year end if a significant deviation should occur.

National Grid follows the outlined guidelines:

- During the work order creation process, a determination is made whether a work order is eligible to accrue AFUDC charges based upon the work order type selected during the work order creation process. The work order types listed below are considered ineligible to receive AFUDC and don't accrue AFUDC. Please note that the list is not comprehensive as other exceptions may exist.
  - Service installations, direct purchases of equipment and furniture, purchases of vehicles or power operated equipment;
  - Purchases and installation of transformers, regulators and meters;
  - Abandonments;
  - Blanket projects/work orders;
  - CIAC related constructions;
  - Preliminary Survey and Investigation ("PSI")
  - ISR related projects in RI

- The capitalization period for AFUDC shall begin when two conditions are present:
  - Capital expenditures for the project have been incurred and charged to FERC account 107
  - Activities necessary to get the project ready for its intended use are in progress.

- The AFUDC ceases once the in-service date is determined and charges are transferred to the Completed Construction not Classified account (CCNC, FERC Account 106).
  - For work orders that have back dated in service dates, AFUDC charges will be automatically reversed out to reflect the accurate amount of accrued AFUDC.
  - For work orders with in service dates during the current month, AFUDC charges are pro-rated based on the number of days in the month before the in-service date.
  - Accrual of AFUDC is suspended on work orders that have been idle for more than 120 days.

- Estimates are created in January using prior year December financials for long term debt, preferred stock and common stock.

- As National Grid does not provide projections for short term debt and CWIP, the estimate is prepared with values as of prior calendar year-end and eligible CWIP is used rather than total CWIP.
- The interest rate for long-term debt and the cost rate for preferred stock are based on the prior year's costs.
- Long term debt (includes LTD< 1 year) is based upon GAAP Financial Reports for prior December 31st. Treasury provides both the balance and rates (by company) as supported by Treasury "CYE Cost of Debt" file. (D = Long Term Debt, d = Long Term Debt Interest Rate)
- The cost rate for common stock is the rate of return granted common equity in the last approved rate proceeding. These numbers do not change in the monthly calculation of actuals.
- Common Equity as calculated from Total Equity in GAAP Financial Reports for prior December 31st, after removal of Preferred Stock and adjusted for Goodwill, and Other Comprehensive Income (OCI) supported by FERC Account 219 Accumulated other comprehensive income are used.

Component	**Symbol**	**Provided by**	**Update & Review Frequency**
Average short-term debt	S	Treasury	Monthly
Short term debt interest rate	s	Treasury	Monthly
Long term debt	D	Treasury	Annual (December)
Long term debt interest rate	d	Treasury	Annual (December)
Preferred stock	P	Treasury	Annual (December)
Preferred stock cost	p	Treasury	Annual (December)
Common equity	C	Financial Reporting	Annual
Common equity cost	c	Regulatory Accounting	Annual (December)
CWIP	W	Plant Accounting	Monthly

- Separate monthly rates for each company are calculated using the FERC formula and elements for the computation of AFUDC as contained in Title 18 CFR Part 101 Electric (Gas) Plant Instruction no. 3(A)(17). Rates are changed only if they meet or exceed the threshold of 25 basis points.
  - Calculations are prepared after the month-end close as required elements of the calculation (Eligible CWIP and Short-Term Debt) are not readily available.
  - The balance of construction work in progress (CWIP) is the two-month average of eligible base CWIP for the current and prior month.
    - Negative CWIP balance driven by CIAC will not result in negative AFUDC amounts.
    - Accruals for Consultants and Contractors are not included in Eligible Base.
  - The balance for short-term debt is the average daily balance in the Money Pool for the current month and the related interest rate is the average rate for the current month.
    - Companies with a negative value in the Money Pool are considered in a borrowing position and the amounts are used for short debt calculation. Negative value in Money Pool as December 31 is used in the yearly estimate calculation.
    - OAA (Open Account Arrangement) balance is also included if considered short term. When third party short-term debt is incurred, it is taken into consideration.

- True-up entries are calculated and prepared at Calendar and Fiscal Year end if the dollar variance exceeds an individual company's materiality threshold.

- AFUDC is capitalized on the company's books by charging FERC Account 107, Construction Work in Progress, as a component of construction cost and crediting Other Income, Account 419.1 – Allowance for Other Funds Used During Construction and/or crediting Interest Charges, Account 432 – Allowance for Borrowed Funds Used During Construction – Credit, as appropriate.

C. Exceptions

National Grid Generation LLC ("GENCO") is classified as non-regulated for GAAP reporting but is treated as a regulated entity for FERC reporting. Because GENCO does not qualify for ASC 980 accounting treatment, it is necessary to make certain adjustments to the recorded amounts. A manual adjustment is made to record incremental debt differences. This rate is calculated by removing the equity component from the equation. Manual adjustments are recorded to reverse the equity component of AFUDC for GAAP and IFRS purposes.

In accordance with GENCO's Power Supply Agreement (PSA) with LIPA, the dense pack assets have a designated AFUDC rate of 4.85% and therefore the debt financing related to these assets is excluded from the rest of the outstanding LTD of GENCO.

Section III: Key Accounting Literature

The treatment of AFUDC under US GAAP depends on whether the company is regulated or unregulated. A Regulated Company must meet the following criteria as stated in ASC Topic 980 *Regulated Operations*:

1. Rates are established by an independent third-party regulator or the entity's own governing board;
2. Rates are intended to recover cost of service; and
3. Rates designed to recover costs can be charged to and collected from customers.

1. Regulated Subsidiary Accounting (ASC 980)

AFUDC is capitalized only during periods of construction and only if it is probable that the regulated company will receive subsequent recovery through the ratemaking process. AFUDC as provided in the Uniform System of Accounts is a two-part allowance. Regulated companies are permitted to capitalize an allowance for funds used during construction which includes borrowing costs incurred for both debt and equity.

1. The debt component includes the cost of short-term debt and long-term debt when so used;
2. The equity component includes the cost of common equity and preferred stock when so used.

2. Unregulated US GAAP (ASC 835)

Unregulated companies, or those companies that do not meet the criteria stated under ASC 980, are not allowed to capitalize AFUDC during periods of construction, but fall under ASC Topic 835 I*nterest* which allows the capitalization of interest. Thus, in this latter case, the capitalized costs only include the debt component of AFUDC.

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Accounting for Allowance for Funds Used During Construction (AFUDC)	

Section VIII: Exhibits and References

Exhibit 1

$A_i = s(S/W) + d(D/D + P + C)(1 - S/W)$

$A_e = [1 - S/W][p(P/D + P + C) + c(C/D + P + C)]$

A_i = Gross allowance for borrowed funds used during construction rate.

A_e = Allowance for other funds used during construction rate.

S = Average short-term debt.

s = Short-term debt interest rate.

D = Long-term debt.

d = Long-term debt interest rate.

P = Preferred stock.

p = Preferred stock cost rate.

C = Common equity

c = Common equity cost rate.

W = Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication.

PUC 6-5

Request:

Referring to PUC 1-17, page 2, please indicate which project budget items fall into the category of "Preliminary Survey and Investigation" charges, as defined in PUC 2-2(d), page 35 of 174.

Response:

As noted in the Company's response to PUC 6-3, historically, the Company has not used Preliminary Survey and Investigation accounting for Gas projects because of the short-term nature of the majority of Gas work and because most Gas work is completed in the year in which it starts. In addition, the Company reviewed its five-year RI ISR Spending Forecast for FY 2022 through FY 2026 (see National Grid's FY 2022 Gas ISR Plan, Section 2, Page 34 of 35 (Bates page 77)) and determined that with the exception of two projects, the Aquidneck Island Long Term Capacity Options and the Cumberland LNG tank replacement, the planned work is short cycle work that is likely to be completed in the year in which it starts.

After consideration, the Company believes it would be appropriate to use Preliminary Survey and Investigation accounting as an exception to the historical practice for Gas for the costs associated with the Aquidneck Island Long Term Capacity Options since the type of activities that will take place in FY 2022 match the definition for Preliminary Survey and Investigation and because the Company has not yet selected an infrastructure option. The Company does not believe this accounting treatment is appropriate for the Cumberland LNG tank replacement project since the project has been selected and engineering design work has begun, thus meeting the definition for inclusion in Construction Work in Progress. National Grid notes that while the decision to use Preliminary Survey and investigation accounting for the Aquidneck Island Long Term Capacity Options impacts the revenue requirement calculation, it does not impact the budget spending agreement reached with the Division for the FY 2022 Gas ISR Plan.

The Company will continue to spend the agreed to budget for this project in FY 2022.

Prepared by or under the supervision of: Amy Smith and Melissa Little

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PUC 6-6

Request:

Please explain why it is reasonable and fair to ratepayers for the Company to be earning a return, taxes, and depreciation on Preliminary Survey and Investigation costs for potential capital projects that have not been fully investigated and there remains significant uncertainty whether they will be constructed any time within the next three to five years. Please also indicate whether any other U.S. state jurisdiction allows for this type of pre-construction rate recovery for Preliminary Survey and Investigation costs.

Response:

The Company does not believe it is fair and reasonable to earn a revenue requirement on Preliminary Survey and Investigation costs for potential capital projects before feasibility of the project is determined and any construction activity on that project begins. Based on the Company's Work Order Life Cycle Playbook referenced in the Company's response to PUC 2-2(d), Preliminary Survey and Investigation charges ("PS&I") are recorded in FERC Account 183 prior to construction. Once a project is determined to be feasible and construction begins, these charges would be reclassified from Account 183 to FERC Account 107, the Construction Work in Progress ("CWIP") account. Therefore, before the feasibility of a capital project is determined, PS&I costs are not included in CWIP and should not be included in the calculation of the Gas ISR revenue requirement.

The Company is not aware of any other U.S. state jurisdiction that allows for this type of pre-construction rate recovery for Preliminary Survey and Investigation costs.

As stated in the Company's response to PUC 6-5, the Company believes it would be appropriate to use Preliminary Survey and Investigation accounting for the costs associated with the Aquidneck Island Long Term Capacity Options. Therefore, the Company would propose to exclude that $4.9 million from the capital investment included in the calculation of the FY 2022 Gas ISR revenue requirement and from any Gas ISR revenue requirement calculation until those dollars are transferred to CWIP. National Grid notes that while the decision to use Preliminary Survey and investigation accounting for the Aquidneck Island Long Term Capacity Options impacts the revenue requirement calculation, it does not impact the budget spending agreement reached with the Division for the FY 2022 Gas ISR Plan. The Company will continue to spend the agreed budget for this project in FY 2022.

Prepared by or under the supervision of: Melissa Little

PUC 6-7

Request:

Referring to the response to PUC 2-2(d), page 35 of 164, please provide a mathematical hypothetical example of how the National Grid companies calculate CWIP as required by National Grid's internal accounting standards on the referenced page. Please also show the extent to which the calculation of CWIP done in accordance with the referenced requirements differ from the way the Company calculates the revenue requirement for a capital project not yet in service that is included in the Gas ISR revenue requirement (please show this with the mathematical hypothetical example).

Response:

Based on the Company's Work Order Life Cycle Playbook, referenced in the response to PUC 2-2(d), Preliminary Survey and Investigation charges ("PS&I") are recorded in FERC Account 183 prior to construction. Once a project is determined to be feasible and construction begins, these charges would be reclassified from FERC Account 183 to FERC Account 107, the Construction Work In Progress (CWIP) account. Therefore, before the feasibility of a capital project is determined, PS&I costs are not included in CWIP and would not be included in the calculation of the Gas ISR revenue requirement.

Please note that the Work Order Lifecycle Playbook mentions the accrual of an Allowance of Funds Used During Construction (AFUDC) on charges recorded in CWIP. AFUDC is not accrued to projects eligible for recovery through the Gas ISR. Please refer to the National Grid U.S. AFUDC policy as provided in the Company's response to PUC 6-4. Ultimately, there is no difference in the way the Company calculates CWIP in its asset ledger and the way the Company calculates the capital spending in CWIP included in the ISR rate base upon which the Gas ISR revenue requirement is calculated. PS&I charges would become a component of the capital spending included in the calculation of the Gas ISR revenue requirement if and when PS&I dollars are transferred to CWIP.

A mathematical hypothetical example is provided in Attachment PUC 6-7.

Prepared by or under the supervision of: Melissa Little

	Project Phase	Assumption/Reference	PS&I (183)	CWIP (107)	PIS (106/101)
			FERC Accounts		
1	Feasibility study costs incurred	$100	$100		
2	Study deems project feasible; construction commences		($100)	$100	
3	Construction costs incurred	$500		$500	
4	Capital Overheads applied (no AFUDC)	10%		$50	
5	Subtotal		$0	$650	$0
6	Project construction complete; assets placed into service			($650)	$650
7	Gross Capital included in ISR Rate Base (ISR capital spending)	Line 5	$0	$650	$0
8	Accumulated Depreciation	30 year life		($11)	
9	Net Rate Base			$639	
10	Average Rate Base	Line 9 * 50%		$320	
	Revenue Requirement				
11	Return & taxes	Line 10 * 9.275% ROE		$30	
12	Depreciation expense	Line 8		$11	
13	Total Revenue Requirement - Year 1			$40	

For purposes of this hypothetical example, (1) tax and book depreciation are equal, and therefore no deferred tax impacts are reflected in the calculation, and (2) all capital investment is incremental to the level of capital investment assumed in base rates.

PS&I = Preliminary Survey & Engineering
CWIP = Construction Work in Progress
PIS = Plant In Service

PUC 6-8

Request:

Referring to the Table on Attachment PUC 3-3-1,

(a) for each line item on the Table, please provide the following:

(i) total revenue requirement originally included in the FY 2021 plan for the line item, and
(ii) the subset of the revenue requirement that will be over-recovered from ratepayers through FY 21 which is associated with the underspending shown in the variance column.

(b) Did the Company make any adjustment to its proposed revenue requirement in its FY 2022 filing to credit customers for having overcompensated the Company for any portion of the $35.5 million in FY 2021 underspending forecasted in the variance column? If so, please explain how this was done. If not, please explain why not, and indicate when and how the Company will reimburse ratepayers.

(c) Please confirm the total revenue requirement credit that is owed to ratepayers from the $35.5 million in underspending.

Response:

(a) The Company has employed the same methodology described in response to Data Request PUC 1-17 to calculate the revenue requirement on capital investments by line item. Attachment PUC 6-8-1, column (d) represents the revenue requirement on FY 2021 capital investment originally included in the FY 2021 Gas ISR plan; column (e) calculates the revenue requirement that will be over-recovered on the forecasted FY 2021 underspending in the variance column (c).

(b) The Company did not make any adjustment in its proposed FY 2022 Gas ISR Plan revenue requirement for the forecasted FY 2021 underspending shown in the variance column. Pursuant to Schedule A, the Distribution Adjustment Charge ("DAC") section of the Company's gas tariff, R.I.P.U.C. NG-GAS No. 101, Section 3.3.3 of the Infrastructure, Safety and Reliability provision, which governs the reconciliation of actual costs and revenue of the Gas ISR Plan, and following past practice in the Company's Gas ISR Plan and Gas ISR reconciliation filings, any impact on the FY 2022 Gas ISR Plan revenue requirement related to any over- or under-spending of ISR Plan investment compared to the approved ISR Plan forecasted investment would be credited to customers through Gas ISR reconciliation factors that are a component of the DAC factors that take effect each November 1. The Gas ISR reconciliation filing due August 1, 2021 will reconcile FY 2021 revenue requirement based on actual cumulative Gas ISR costs and revenue billed through the Gas ISR factors through March 2021. With respect to the impact of the FY 2021 underspending on the FY 2022 revenue requirement, which the Company would be recovering from customers during the period April 2021 through March 2022, the Company would reconcile the revenue billed and the FY 2022 revenue requirement based on actual cumulative Gas ISR costs and reflect the reduction in the FY 2022 revenue requirement in the reconciliation filing submitted on August 1, 2022.

The Company would not oppose reflecting the most recent forecast of FY 2021 capital spending in its calculation of the FY 2022 Gas ISR Plan revenue requirement, as an exception to Section 3.3.3 to the Company's gas tariff and past practice, due to the amount of the projected underspending on FY 2021 investment and in consideration of the extraordinary circumstances facing customers under the global pandemic. The Company would like to note, however, that one benefit to keeping the impact of the $35 million in FY 2021 underspending in the FY 2022 Gas ISR reconciliation factor, is the potential to mitigate bill impacts of changes in other components of the DAC and Gas Cost Recovery ("GCR") factor, both of which change annually on November 1.

(c) Refer to Attachment PUC 6-8-1, Line 52(c). If the actual FY 2021 capital investment and the Cost of Removal agree with the forecasted amounts in Column (b), the Company will over recover about $2.5 million through its FY 2021 Gas ISR Plan. The reduction in the revenue requirement will be presented in the FY 2021 Gas ISR Reconciliation filing to be submitted by August 1, 2021 and credited to customers through ISR reconciliation factors effective November 1, 2021.

Similarly, please refer to Attachment 6-8-3. The Company will over recover approximately $4 million through its FY 2022 Gas ISR Plan on the $35 million in FY 2021 underspending.

Updated FY 2021 ISR Investment Forecast per Attachment PUC 3-3-1
The Narragansett Electric Company
d/b/a National Grid - RI Gas
Capital Spending by Investment Categories - Detail

	Categories	Budget	FY 2021 Forecast	Variance	Revenue Requirement in RIPUC 4996	Revenue Requirement of Underspending
		(a)	(b)	(c)=(b)-(a)	(d) = Line 54(a)×(a)	(e) = Line 54(c)×(c)
	NON-DISCRETIONARY					
	Public Works					
1	CSC/Public Works - Non-Reimbursable	$17,368,000	$15,122,000	($2,246,000)	$1,118,249	($162,228)
2	CSC/Public Works - Reimbursable	$1,403,000	$850,000	($553,000)	$90,333	($39,943)
3	CSC/Public Works - Reimbursements	($1,403,000)	($1,650,000)	($247,000)	($90,333)	($17,841)
4	**Public Works Total**	**$17,368,000**	**$14,322,000**	**($3,046,000)**	**$1,118,249**	**($220,012)**
	Mandated Programs					
5	Corrosion	$1,166,000	$1,166,000	$0	$75,074	$0
6	Purchase Meters (Replacements)	$4,852,000	$5,423,000	$571,000	$312,399	$41,243
7	Reactive Leaks (CI Joint Encapsulation/Service Replacement)	$12,280,000	$9,097,000	($3,183,000)	$790,655	($229,907)
8	Service Replacements (Reactive) - Non-Leaks/Other	$2,096,000	$1,600,000	($496,000)	$134,952	($35,826)
9	Main Replacement (Reactive) - Maintenance (incl Water Intrusion)	$680,000	$1,139,000	$459,000	$43,782	$33,153
10	Transmission Station Integrity	$610,000	$42,000	($568,000)	$39,275	($41,026)
11	Other Mandated	$0	$85,000	$85,000	$0	$6,140
12	**Mandated Total**	**$21,684,000**	**$18,552,000**	**($3,132,000)**	**$1,396,137**	**($226,223)**
	Damage / Failure (Reactive)					
13	**Damage / Failure (Reactive)**	**$249,000**	**$93,000**	**($156,000)**	**$16,032**	**($11,268)**
14	**NON-DISCRETIONARY TOTAL**	**$39,301,000**	**$32,967,000**	**($6,334,000)**	**$2,530,418**	**($457,503)**
	DISCRETIONARY					
	Proactive Main Replacement					
15	Main Replacement (Proactive) - Leak Prone Pipe	$59,250,000	$56,808,000	($2,442,000)	$3,814,847	($176,385)
16	Main Replacement (Proactive) - Large Diameter LPCI Program	$3,398,000	$1,438,000	($1,960,000)	$218,782	($141,570)
17	Atwells Avenue	$5,081,000	$5,520,000	$439,000	$327,143	$31,709
18	**Proactive Main Replacement Total**	**$67,729,000**	**$63,766,000**	**($3,963,000)**	**$4,360,772**	**($286,246)**
	Proactive Service Replacement					
19	**Proactive Service Replacement Total**	**$350,000**	**$160,000**	**($190,000)**	**$22,535**	**($13,724)**
	Reliability					
20	Gas System Control	$118,000	$64,000	($54,000)	$7,598	($3,900)
21	System Automation	$1,252,000	$1,115,000	($137,000)	$80,611	($9,895)
22	Heater Installation Program	$2,961,000	$2,524,000	($437,000)	$190,646	($31,564)
23	Pressure Regulating Facilities	$7,849,000	$4,297,000	($3,552,000)	$505,363	($256,560)
24	Allens Ave Multi Station Rebuild	$6,200,000	$8,421,000	$2,221,000	$399,191	$160,422
25	Take Station Refurbishment	$995,000	$666,000	($329,000)	$64,064	($23,764)
26	Valve Installation/Replacement (incl Storm Hardening & Middletown/Newport)	$676,000	$376,000	($300,000)	$43,525	($21,669)
27	Gas System Reliability	$2,371,000	$598,000	($1,773,000)	$152,658	($128,063)
28	I&R - Reactive	$1,392,000	$1,399,000	$7,000	$89,625	$506
29	Distribution Station Over Pressure Protection	$3,636,000	$1,620,000	($2,016,000)	$234,106	($145,615)
30	LNG	$6,433,000	$2,657,000	($3,776,000)	$414,193	($272,739)
31	Aquidneck Island Long Term Capacity Options	$0	$700,000	$700,000	$0	$50,561
32	Replace Pipe on Bridges	$1,500,000	$151,000	($1,349,000)	$96,578	($97,438)
33	Access Protection Remediation	$260,000	$260,000	$0	$16,740	$0
34	Tools & Equipment	$603,000	$603,000	$0	$38,825	$0
35	**Reliability Total**	**$36,246,000**	**$25,451,000**	**($10,795,000)**	**$2,333,720**	**($779,719)**
36	**SUBTOTAL DISCRETIONARY (Without Gas Expansion)**	**$104,325,000**	**$89,377,000**	**($14,948,000)**	**$6,717,028**	**($1,079,689)**
	Southern RI Gas Expansion Project					
37	Pipeline	$38,798,000	$40,252,000	$1,454,000	$2,498,032	$105,022
38	Other Upgrades/Investments	$451,000	$710,000	$259,000	$29,038	$18,707
39	Regulator Station Investment	$1,211,000	$420,000	($791,000)	$77,971	($57,134)
40	**Southern RI Gas Expansion Project Total**	**$40,460,000**	**$41,382,000**	**$922,000**	**$2,605,041**	**$66,596**
41	**DISCRETIONARY TOTAL (With Gas Expansion)**	**$144,785,000**	**$130,759,000**	**($14,026,000)**	**$9,322,069**	**($1,013,093)**
42	**CAPITAL ISR TOTAL (Base Capital - Without Gas Expansion)**	**$143,626,000**	**$122,344,000**	**($21,282,000)**	**$9,247,446**	**($1,537,192)**
43	**CAPITAL ISR TOTAL (With Gas Expansion)** Amount does not include incremental paving associated with new RI Paving Law or PE Stamps	**$184,086,000**	**$163,726,000**	**($20,360,000)**	**$11,852,487**	**($1,470,596)**
	Incremental Costs					
44	PE Stamps[1]	$1,515,000		($1,515,000)	$97,544	($109,428)
45	Incremental Paving - Main Installation	$5,596,000		($5,596,000)	$360,302	($404,197)
46	Incremental Paving - Patches	$4,801,000		($4,801,000)	$309,115	($346,775)
47	Incremental Paving - Southern RI Gas Expansion[2]	$2,614,000		($2,614,000)	$168,304	($188,808)
48	**Incremental Costs Total**	**$14,526,000**		**($14,526,000)**	**$935,265**	**($1,049,208)**
49	**CAPITAL ISR TOTAL (with Gas Expansion, PE Stamps, and Incremental Paving)**	**$198,612,000**	**$163,726,000**	**($34,886,000)**	**$12,787,753**	**($2,519,804)**

			Approved per Docket 4996	Updated per Forecast	Variance		
			(a)	(b)	(c)=(b)-(a)		
50	FY21 Depreciation, Return and Taxes associated with FY21 investment		$7,524,753	$5,933,948	($1,590,804)		
51	FY21 Property tax associated with FY21 investment		$5,263,000	$4,334,000	($929,000)		
52	Total FY21 revenue requirement associated with FY21 investment		$12,787,753	$10,267,948	($2,519,804)		
53	Total FY21 Investment Plan Spend		$198,612,000	$163,726,000	($34,886,000)		
54	Revenue Requirement Ratio of FY21 Capital Investment		6.44%	6.27%	7.22%		
Line notes:							
44	The actual costs and forecasts for PE Stamps are included within the applicable ISR categories that incur PE Stamp costs, above.						
45	The actual costs and forecasts for Incremental Paving - Main Installation are included within the applicable ISR categories that incur Main Installation paving costs, above.						
46	The actual costs and forecasts for Incremental Paving - Patches are included within the applicable ISR categories that incur Patch paving costs, above.						
47	The actual costs and forecasts for Incremental Paving - Southern RI Gas Expansion are included within the Southern RI Gas Expansion Project categories above.						
50(a)	Docket No. 4996, Rev. Sec. 3, Att. 1R, Page						
51(a)	Docket No. 4996, Rev. Sec. 3, Att. 1R, Page 20, (Line 52(K) + Line 61(k))×1,000						
50(b)	Attachment PUC 6-8-2, Page 2, Line 29, Col (a)						
51(b)	Attachment PUC 6-8-2, Page 10, (Line 52(K) + Line 61(k))×1,000						
52	Line 50 + Line 51						
53	Line 49						
54	Line 52 ÷ Line 53						

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement updated
Annual Revenue Requirement Summary

Line No.		Approved Fiscal Year 2020 (a)	Fiscal Year 2021 (b)	Fiscal Year 2022 (c)
	Operation and Maintenance Expenses			
1	Forecasted Gas Infrastructure, Safety, and Reliability O&M Expenses	$0	$0	$0
	Capital Investment:			
2	Actual Revenue Requirement on FY 2018 Incremental Capital Included in ISR Rate Base	$663,731	$676,445	$690,881
3	Actual Revenue Requirement on FY 2019 Incremental Capital Included in ISR Rate Base	($666,404)	$292,352	$291,583
4	Forecasted Revenue Requirement on FY 2020 Capital Included in ISR Rate Base	$4,123,711	$9,556,813	$9,305,647
5	Forecasted Revenue Requirement on FY 2021 Capital Included in ISR Rate Base		$5,933,948	$11,723,625
6	Total Capital Investment Revenue Requirement	$4,121,038	$16,459,558	$22,011,736
7	FY 2020 Property Tax Recovery Adjustment	$2,353,682		
8	FY 2021 Property Tax Recovery Adjustment		$3,781,325	
9	Total Capital Investment Component of Revenue Requirement	**$6,474,720**	**$20,240,883**	**$22,011,736**
10	Total Fiscal Year Revenue Requirement	**$6,474,720**	**$20,240,883**	**$22,011,736**
11	Incremental Fiscal Year Rate Adjustment		**$13,766,163**	

Column Notes:
(a) RIPUC Docket No. 4916, Revised Section 3, Attachment 1R, Page 1 of 19

Line Notes for Columns (b) and (c):
1~4 RIPUC Docket No. 4996, Revised Section 3, Attachment 1R, Page 1, Lines 1 through 4
5 Page 2 of 12, Line 29, Col. (a), and Col. (b)
6 Sum of Lines 2 through Line 5
8 Page 10 of 12, Line 63, Column (k) × 1,000
9 Sum of Line 6 through Line 8
10 Line 1 + Line 9
11 Line 10 Col (b) - Line 10 Col (a)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement updated
Computation of Revenue Requirement on FY 2021 Forecasted Incremental Gas Capital Investment

Line No.				Fiscal Year 2021 (a)	Fiscal Year 2022 (b)
	Depreciable Net Capital Included in ISR Rate Base				
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 5 of 12 , Line 3 ,Col (d)		$148,106,599	$0
2	Retirements	Page 5 of 12 , Line 9 ,Col (d)	1/	$19,158,383	$0
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$128,948,216	$128,948,216
	Change in Net Capital Included in ISR Rate Base				
4	Capital Included in ISR Rate Base	Line 1		$148,106,599	$0
5	Depreciation Expense	Page 8 of 12, Line 78(c)		$40,700,586	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$107,406,012	$107,406,012
7	Cost of Removal	Page 5 of 12 , Line 6 ,Col (d)		$14,505,886	$14,505,886
8	**Net Plant Amount**	**Line 6 + Line 7**		**$121,911,898**	**$121,911,898**
	Deferred Tax Calculation:				
9	Composite Book Depreciation Rate	Page 6 of 12, Line 86(e)	1/	2.99%	2.99%
10	Tax Depreciation	Year 1 =Page 3 of 12, Line 21, Col (a); then = Page 3 of 12, Col (d)		$143,185,602	$1,573,835
11	Cumulative Tax Depreciation	Year 1 = Line 10; then = Prior Year Line 11 + Current Year Line 10		$143,185,602	$144,759,437
12	Book Depreciation	Year 1 = Line 3 × Line 9 × 50% ; then = Line 3 × Line 9		$1,927,776	$3,855,552
13	Cumulative Book Depreciation	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12		$1,927,776	$5,783,328
14	Cumulative Book / Tax Timer	Line 11 - Line 13		$141,257,826	$138,976,110
15	Effective Tax Rate			21.00%	21.00%
16	Deferred Tax Reserve	Line 14 × Line 15		$29,664,144	$29,184,983
17	Add: FY 2021 Federal NOL utilization	Page 5 of 12 , Line 12 ,Col (d)		($4,944,950)	($4,944,950)
18	Net Deferred Tax Reserve before Proration Adjustment	Line 16 + Line 17		$24,719,194	$24,240,033
	ISR Rate Base Calculation:				
19	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$121,911,898	$121,911,898
20	Accumulated Depreciation	- Line 13		($1,927,776)	($5,783,328)
21	Deferred Tax Reserve	- Line 18		($24,719,194)	($24,240,033)
22	Year End Rate Base before Deferred Tax Proration	Sum of Lines 19 through 21		$95,264,929	$91,888,538
	Revenue Requirement Calculation:				
23	Average Rate Base befor Deferred Tax Proration Adjustment	Year 1 = Current Year Line 22 ÷ 2; then = (Prior Year Line 22 + Current Year Line 22) ÷ 2		$47,632,464	$93,576,733
24	Proration Adjustment	Page 4 of 12, Line 41, Col (j) and Col (k)		$3,355	($20,567)
25	Average ISR Rate Base after Deferred Tax Proration	Line 23 + Line 24		$47,635,819	$93,556,166
26	Pre-Tax ROR	Page 12 of 12, Line 30, Column (e)		8.41%	8.41%
27	Return and Taxes	Line 25 × Line 26		$4,006,172	$7,868,074
28	Book Depreciation	Line 12		$1,927,776	$3,855,552
29	**Annual Revenue Requirement**	**Sum of Lines 27 through 28**		**$5,933,948**	**$11,723,625**

1/ 2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement updated
Calculation of Tax Depreciation and Repairs Deduction on FY 2021 Incremental Capital Investments

Line No.				Fiscal Year 2021 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 2 of 12, Line 1		$148,106,599
2	Capital Repairs Deduction Rate	Per Tax Department	1/	85.28%
3	Capital Repairs Deduction	Line 1 × Line 2		$126,305,307
	Bonus Depreciation			
4	Plant Additions	Line 1		$148,106,599
5	Less Capital Repairs Deduction	Line 3		$126,305,307
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$21,801,292
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%
8	Plant Eligible for Bonus Depreciation	Line 6 × Line 7		$0
9	Bonus Depreciation Rate ()	Per Tax Department		0.00%
10	Bonus Depreciation Rate ()	Per Tax Department		0.00%
11	Total Bonus Depreciation Rate	Line 9 + Line 10		0.00%
12	Bonus Depreciation	Line 8 × Line 11		$0
	Remaining Tax Depreciation			
13	Plant Additions	Line 1		$148,106,599
14	Less Capital Repairs Deduction	Line 3		$126,305,307
15	Less Bonus Depreciation	Line 12		$0
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$21,801,292
17	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%
18	Remaining Tax Depreciation	Line 16 × Line 17		$817,548
19	FY21 tax (gain)/loss on retirements	Per Tax Department	2/	1,556,861
20	Cost of Removal	Page 2 of 12, Line 7		$14,505,886
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19 & 20		$143,185,602

20 Year MACRS Depreciation

MACRS basis: $21,801,292

(b)	(c)	(d)	(e)
Fiscal Year		Annual	Cumulative
2021	3.75%	$817,548	$143,185,602
2022	7.22%	$1,573,835	$144,759,437
2023	6.68%	$1,455,672	$146,215,110
2024	6.18%	$1,346,666	$147,561,775
2025	5.71%	$1,245,508	$148,807,283
2026	5.29%	$1,152,198	$149,959,481
2027	4.89%	$1,065,647	$151,025,129
2028	4.52%	$985,854	$152,010,983
2029	4.46%	$972,774	$152,983,757
2030	4.46%	$972,556	$153,956,312
2031	4.46%	$972,774	$154,929,086
2032	4.46%	$972,556	$155,901,642
2033	4.46%	$972,774	$156,874,415
2034	4.46%	$972,556	$157,846,971
2035	4.46%	$972,774	$158,819,744
2036	4.46%	$972,556	$159,792,300
2037	4.46%	$972,774	$160,765,074
2038	4.46%	$972,556	$161,737,629
2039	4.46%	$972,774	$162,710,403
2040	4.46%	$972,556	$163,682,959
2041	2.23%	$486,387	$164,169,345
	100.00%	$21,801,292	

1/ Capital Repairs percentage is based on a three-year average of FYs 2017, 2018 and 2019 capital repairs rates.
2/ FY 2021 estimated tax loss on retirements is tax department estimate

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement updated
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investments

Line No.	**Deferred Tax Subject to Proration**		(a) FY21	(b) FY22
1	Book Depreciation	#REF!	$1,927,776	$3,855,552
2	Bonus Depreciation	Page 3 of 12 , Line 12 ,Col (a)	$0	$0
3	Remaining MACRS Tax Depreciation	Year 1= - Page 3 of 12, Line 18, Col (a); then = - Page 3 of 12, Col (d)	($817,548)	($1,573,835)
4	FY21 tax (gain)/loss on retirements	Page 3 of 12 , Line 19 ,Col (a)	($1,556,861)	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($446,633)	$2,281,716
6	Effective Tax Rate		21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	($93,793)	$479,160
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	Page 3 of 12 , Line 3 ,Col (a)	($126,305,307)	
9	Cost of Removal	Page 2 of 12 , Line 7 ,Col (a)	($14,505,886)	
10	Book/Tax Depreciation Timing Difference at 3/31/2021			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($140,811,193)	
12	Effective Tax Rate		21%	
13	Deferred Tax Reserve	Line 11 × Line 12	($29,570,351)	
14	Total Deferred Tax Reserve	Line 7 + Line 13	($29,664,144)	$479,160
15	Net Operating Loss	- Page 2 of 12 , Line 17 ,Col (a)	$4,944,950	
16	Net Deferred Tax Reserve	Line 14 + Line 15	($24,719,194)	$479,160
	Allocation of FY 2021 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	($446,633)	$2,281,716
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($140,811,193)	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($141,257,826)	$2,281,716
20	Total FY 2021 Federal NOL	- Page 2 of 12 , Line 17 ,Col (a)÷21%	$23,547,380	
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$23,472,927	
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20	$74,453	
23	Effective Tax Rate		21%	
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23	$15,635	
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($78,158)	$479,160

	Proration Calculation	(h) Number of Days in Month	(i) Proration Percentage	(j) FY21	(k) FY22
26	April	30	91.78%	($5,978)	$36,648
27	May	31	83.29%	($5,425)	$33,257
28	June	30	75.07%	($4,889)	$29,975
29	July	31	66.58%	($4,336)	$26,584
30	August	31	58.08%	($3,783)	$23,192
31	September	30	49.86%	($3,248)	$19,910
32	October	31	41.37%	($2,694)	$16,519
33	November	30	33.15%	($2,159)	$13,237
34	December	31	24.66%	($1,606)	$9,846
35	January	31	16.16%	($1,053)	$6,454
36	February	28	8.49%	($553)	$3,391
37	March	31	0.00%	$0	$0
38	Total	365		($35,724)	$219,014
39	Deferred Tax Without Proration	Line 25		($78,158)	$479,160
40	Average Deferred Tax without Proration	Line 39 × 0.5		($39,079)	$239,580
41	Proration Adjustment	Line 38 - Line 40		$3,355	($20,567)

Column Notes:
(i) Sum of remaining days in the year (Col (h)) divided by 365
(j) & (k) Current Year Line 25 ÷ 12 × Current Month Col (i)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement updated
FY 2018 - FY 2021 Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2018 (a)	Actual Fiscal Year 2019 (b)	Plan Fiscal Year 2020 (c)	Plan Fiscal Year 2021 (d)
	Capital Investment					
1	ISR-eligible Capital Investment	Col (a)=Docket No. 4678 FY18 Reconciliation Filing; Col (b)=Docket No. 4781 FY19 Reconciliation Filing; Col (c)=Docket No. 4916 FY20 Plan Filing; Col(d)=Section 2, Table 1	$97,809,718	$92,263,000	$154,551,592	$148,106,599
2	ISR-eligible Capital Additions included in Rate Base per RIPUC Docket No. 4770	Docket No. 4770 Schedule MAL-11-Gas Page 5, Col (a)=Lines 1(a) + 1(b); Col(b)=Lines 1(c) + 1(d); Col(c)= Line 1(e)	$93,177,000	$93,177,000	$38,823,750	$0
3	Incremental ISR Capital Investment	Line 1 - Line 2	$4,632,718	($914,000)	$115,727,842	$148,106,599
	Cost of Removal					
4	ISR-eligible Cost of Removal	Col (a) Docket No. 4678 FY 2018 ISR Reconciliation Filing; Col (b) Docket No. 4781 FY 2019 ISR Reconciliation Filing; Col (c) Docket No. 4916 FY20 Plan Filing; Col(d)=Section 2, Table 1	$8,603,224	$11,583,085	$7,910,408	$15,619,401
5	ISR-eligible Cost of Removal in Rate Base per RIPUC Docket No. 4770	Schedule 6-GAS, Docket No. 4770: Col(a)=[P1]L23+L42×7÷12+Docket 4678 Page 2, Line 7x3÷12; Col(b)=[P1]L42×5÷12+[P2]L18×7÷12; Col (c)=[P2]L18×5÷12+L39×7÷12; Col (d) = [P2] L39×5÷12+L60×7÷12	$6,662,056	$5,956,522	$3,105,878	$1,113,515
6	Incremental Cost of Removal	Line 4 - Line 5	$1,941,168	$5,626,564	$4,804,530	$14,505,886
	Retirements					
7	ISR-eligible Retirements	Col (a) Docket No. 4678 FY 2018 ISR Reconciliation Filing; Col (b) Docket No. 4781 FY 2019 ISR Reconciliation Filing; Col (c) Docket No. 4916 FY20 Plan Filing; Col(d)=FY21 Planned Investment x 3-year average actual retirement rate FY17 - FY19	$24,056,661	$6,531,844	$14,753,610	$20,635,188
8	ISR-eligible Retirements per RIPUC Docket No. 4770	Schedule 6-GAS, Docket No. 4770: Col(a)=[P1]L24+L43×7÷12+ Docket 4678 Page 2, Line 2x3÷12; Col(b)=[P1]L43×5÷12+[P2]L19×7÷12 Col (c)=[P2]L19×5÷12+L40×7÷12; Col (d) = [P2]L40×5÷12+L61×7÷12	$11,997,233	$7,899,865	$4,119,186	$1,476,805
9	Incremental Retirements	Line 7 - Line 8	$12,059,428	($1,368,021)	$10,634,424	$19,158,383
	(NOL)/ NOL Utilitization					
10	ISR (NOL)/NOL Utilization Per ISR	Page 11 of 12, Line 10	($6,051,855)	$1,091,119	$2,402,039	$2,653,232
11	ISR NOL Utilization Per Docket 4770	Schedule 11-Gas Page 11, Docket No. 4770: Col (a)= L40×5÷12; Col (b) = L40×5÷12+L48×7÷12; Col (c) = P11,L48×5÷12+P12,L39×7÷12; Col (d) = P12,L39×5÷12+P12,L49×7÷12	$0	$804,769	$3,063,059	$7,598,182
12	Incremental (NOL)/NOL Utilization	Line 10 - Line 11	($6,051,855)	$286,350	($661,020)	($4,944,950)

Note: The FY21 updated ISR capital investment of $163,726,000 is the sum of Line 1 and Line 4.

The Narragansett Electric Company
d/b/a National Grid
ISR Depreciation Expense per Rate Case RIPUC Docket No. 4770

	Account No.	Account Title	Test Year June 30, 2017 (a) 1/	ARO Adjustment (b)	Adjustments June 30, 2017 (c)	Adjusted Balance (d) = (a) + (b) + (c)	Proposed Rate (e)	Depreciation Expense (f) = (d) x (e)
		Intangible Plant						
1	302.00	Franchises And Consents	$213,499	$0	$0	$213,499	0.00%	$0
2	303.00	Misc. Intangible Plant	$25,427	$0	$0	$25,427	0.00%	$0
3	303.01	Misc. Int Cap Software	$19,833,570	$0	$9,991,374	$29,824,944	0.00%	$0
4								
5		Total Intangible Plant	$20,072,496	$0	$9,991,374	$30,063,870		$0
6								
7		Production Plant						
8								
9	304.00	Production Land Land Rights	$364,912	$0	$0	$364,912	0.00%	$0
10	305.00	Prod. Structures & Improvements	$2,693,397	$0	$0	$2,693,397	15.05%	$405,356
11	307.00	Production Other Power	$46,159	$0	$0	$46,159	7.16%	$3,305
12	311.00	Production LNG Equipme	$3,167,445	$0	$0	$3,167,445	11.40%	$361,089
13	320.00	Prod. Other Equipment	$1,106,368	$0	$0	$1,106,368	6.69%	$74,016
14								
15		Total Production Plant	$7,378,281	$0	$0	$7,378,281		$843,766
16								
17		Storage Plant						
18								
19	360.00	Stor Land & Land Rights	$261,151	$0	$0	$261,151	0.00%	$0
20	361.03	Storage Structures Improvements	$3,385,049	$0	$0	$3,385,049	0.99%	$33,512
21	362.04	Storage Gas Holders	$4,606,338	$0	$0	$4,606,338	0.04%	$1,843
22	363.00	Stor. Purification Equipment	$13,891,210	$0	$0	$13,891,210	3.37%	$468,134
23								
24		Total Storage Plant	$22,143,748	$0	$0	$22,143,748		$503,488
25								
26		Distribution Plant						
27								
28	374.00	Dist. Land & Land Rights	$956,717	$0	$0	$956,717	0.00%	$0
29	375.00	Gas Dist Station Structure	$10,642,632	$0	$0	$10,642,632	1.15%	$122,390
30	376.00	Distribution Mains	$46,080,760	$0	$0	$46,080,760	3.61%	$1,663,515
31	376.03	Dist. River Crossing Main	$695,165	$0	$0	$695,165	3.61%	$25,095
32	376.04	Mains - Steel And Other - Sl	$4,190	$0	$0	$4,190	0.00%	$0
33	376.06	Dist. District Regulator	$14,213,837	$0	$0	$14,213,837	3.61%	$513,120
34	376.11	Gas Mains Steel	$57,759,572	$0	$0	$57,759,572	3.31%	$1,908,954
35	376.12	Gas Mains Plastic	$382,797,443	$0	$0	$382,797,443	2.70%	$10,316,391
36	376.13	Gas Mains Cast Iron	$5,556,209	$0	$0	$5,556,209	8.39%	$465,888
37	376.14	Gas Mains Valves	$222,104	$0	$0	$222,104	3.61%	$8,018
38	376.15	Propane Lines	$0	$0	$0	$0	3.61%	$0
39	376.16	Dist. Cathodic Protect	$1,569,576	$0	$0	$1,569,576	3.61%	$56,662
40	376.17	Dist. Joint Seals	$63,067,055	$0	$0	$63,067,055	4.63%	$2,920,005
41	377.00	T&D Compressor Sta Equipment	$248,656	$0	$0	$248,656	1.07%	$2,661
42	377.62	1/ 5360-Tanks ARO	$299	($299)	$0	$0	0.00%	$0
43	378.10	Gas Measur & Reg Sta Equipment	$19,586,255	$0	$0	$19,586,255	2.08%	$407,394
44	378.55	Gas M&Reg Sta Eqp RTU	$372,772	$0	$0	$372,772	6.35%	$23,671
45	379.00	Dist. Measur. Reg. Gs	$11,033,164	$0	$0	$11,033,164	2.22%	$244,936
46	379.01	Dist. Meas. Reg. Gs Eq	$1,399,586	$0	$0	$1,399,586	0.00%	$0
47	380.00	Gas Services All Sizes	$331,205,854	$0	$0	$331,205,854	3.05%	$10,101,779
48	381.10	Sml Meter& Reg Bare Co	$26,829,565	$0	$0	$26,829,565	1.76%	$472,200
49	381.30	Lrg Meter& Reg Bare Co	$15,779,214	$0	$0	$15,779,214	1.76%	$277,714
50	381.40	Meters	$9,332,227	$0	$0	$9,332,227	0.96%	$89,589
51	382.00	Meter Installations	$675,201	$0	$0	$675,201	3.66%	$24,712
52	382.20	Sml Meter& Reg Installation	$43,145,998	$0	$0	$43,145,998	3.66%	$1,579,144
53	382.30	Lrg Meter&Reg Installation	$2,524,025	$0	$0	$2,524,025	3.66%	$92,379
54	383.00	Dist. House Regulators	$937,222	$0	$0	$937,222	0.67%	$6,279
55	384.00	T&D Gas Reg Installs	$1,216,551	$0	$0	$1,216,551	1.56%	$18,978
56	385.00	Industrial Measuring And Regulating Station Equipment	$540,187	$0	$0	$540,187	4.18%	$22,580
57	385.01	Industrial Measuring And Regulating Station Equipment	$255,921	$0	$0	$255,921	0.00%	$0
58	386.00	Other Property On Customer Premises	$271,765	$0	$0	$271,765	0.23%	$625
59	386.02	Dist. Consumer Prem Equipment	$110,131	$0	$0	$110,131	0.00%	$0
60	387.00	Dist. Other Equipment	$930,079	$0	$0	$930,079	2.15%	$19,997
61	388.00	1/ ARO	$5,736,827	($5,736,827)	$0	$0	0.00%	$0
62								
63		Total Distribution Plant	$1,055,696,761	($5,737,126)	$0	$1,049,959,635	2.99%	$31,384,677
64								
65		General Plant						
66								
67	389.01	General Plant Land Lan	$285,357	$0	$0	$285,357	0.00%	$0
68	390.00	Structures And Improvements	$7,094,532	$0	$0	$7,094,532	3.12%	$221,349
69	391.01	Gas Office Furniture & Fixture	$274,719	$0	$0	$274,719	6.67%	$18,324
70	394.00	General Plant Tools Shop (Fully Dep)	$26,487	$0	$0	$26,487	0.00%	$0
71	394.00	General Plant Tools Shop	$5,513,613	$0	$0	$5,513,613	5.00%	$275,681
72	395.00	General Plant Laboratory	$221,565	$0	$0	$221,565	6.67%	$14,778
73	397.30	Communication Radio Site Specific	$387,650	$0	$0	$387,650	5.00%	$19,383
74	397.42	Communication Equip Tel Site	$63,481	$0	$0	$63,481	20.00%	$12,696
75	398.10	Miscellaneous Equipment (Fully Dep)	$1,341,386	$0	$0	$1,341,386	0.00%	$0
76	398.10	Miscellaneous Equipment	$2,789,499	$0	$0	$2,789,499	6.67%	$186,060
77	399.10	1/ ARO	$342,146	($342,146)	$0	$0	0.00%	$0
78								
79		Total General Plant	$18,340,436	($342,146)	$0	$17,998,289	4.16%	$748,271
80								
81		Grand Total - All Categories	$1,123,631,722	($6,079,273)	$9,991,374	$1,127,543,823	3.05%	$33,480,202
82							2.97%	
83		Other Utility Plant Assets						
84			Line 63		Total Distribution Plant	$1,049,959,635	2.99%	$31,384,677
85			Line 73 + Line 74		Communication Equipment	$451,132	7.11%	$32,079
86					Total ISR Tangible Plant	$1,050,410,767	2.99%	$31,416,756
					Non ISR Assets	$77,133,057		

Lines 1 through 81 - per RIPUC Docket No. 4770 Compliance filing dated August 16, 2018 , Compliance Attachment 2, Schedule 6-GAS, Pages 3 & 4

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

The Narragansett Electric Company
d/b/a National Grid
Gas ISR Depreciation Expense

Line No	Description		Reference	Amount	Less non-ISR eligible Plant	ISR Amount
				(a)	(b)	(c)
1	Total Company Rate Year Depreciation		Sum of Page 2, Line 16 and Line 17	$39,136,909		
2	Total Company Test Year Depreciation		Per Company Books	$33,311,851		
3	Less: Reserve adjustments		Page 4, Line 29, Col (b) + Col (c)	($15,649)		
4	Adjusted Total Company Test Year Depreciation Expense		Line 2 + Line 3	$33,296,202		
5	Depreciation Expense Adjustmen		Line 1 - Line 4	$5,840,707		
6						
7				Per Book		
8	Test Year Depreciation Expense 12 Months Ended 06/30/17:			Amount		
9	Total Gas Utility Plant 06/30/17		Page 4, Line 27, Col (d)	$1,405,994,678	($77,133,057)	$1,328,861,622
10	Less Non Depreciable Plant		Sum of Page 3, Line 5, Col (d) and Page 4, Line 25, Col (e)	($308,514,725)		($308,514,725)
11	Depreciable Utility Plant 06/30/17		Line 9 + Line 10	$1,097,479,953	($77,133,057)	$1,020,346,897
12						
13	Plus: Added Plant 2 Mos Ended 08/31/17		Schedule 11-GAS, Page 3, Line 4	$19,592,266		$19,592,266
14	Less: Retired Plant 2 Months Ended 08/31/17	1/	Line 13 x Retirement Rate	($1,345,989)		($1,345,989)
15	Depreciable Utility Plant 08/31/17		Line 11 + Line 13 + Line 14	$1,115,726,231	($77,133,057)	$1,020,346,897
16						
17	Average Depreciable Plant for Year Ended 08/31/17		(Line 11 + Line 15)/2	$1,106,603,092		$1,106,603,092
18						
19	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.38%		
20						
21	Book Depreciation Reserve 06/30/17		Page 5, Line 72, Col (d)	$357,576,825		$357,576,825
22	Plus: Book Depreciation Expense		Line 17 x Line 19	$6,233,864		$6,233,864
23	Less: Net Cost of Removal/(Salvage)	2/	Line 13 x Cost of Removal Rate	($1,014,879)		($1,014,879)
24	Less: Retired Plant		Line 14	($1,345,989)		($1,345,989)
25	Book Depreciation Reserve 08/31/17		Sum of Line 21 through Line 24	$361,449,821		
26						
27	Depreciation Expense 12 Months Ended 08/31/18					
28	Total Utility Plant 08/31/17		Line 9 + Line 13 + Line 14	$1,424,240,956	($77,133,057)	$1,347,107,900
29	Less Non Depreciable Plant		Line 10	($308,514,725)		($308,514,725)
30	Depreciable Utility Plant 08/31/17		Line 28 + Line 29	$1,115,726,231		$1,038,593,175
31						
32	Plus: Plant Added in 12 Months Ended 08/31/18		Schedule 11-GAS, Page 3, Line 11	$115,710,016		$115,710,016
33	Less: Plant Retired in 12 Months Ended 08/31/18		Line 32 x Retirement rate	($7,949,278)		($7,949,278)
34	Depreciable Utility Plant 08/31/18		Sum of Line 30 through Line 33	$1,223,486,969		$1,146,353,912
35						
36	Average Depreciable Plant for 12 Months Ended 08/31/18		(Line 30 + Line 34)/2	$1,169,606,600		$1,092,473,543
37						
38	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.38%		3.38%
39						
40	Book Depreciation Reserve 08/31/17		Line 25	$361,449,821		
41	Plus: Book Depreciation 08/31/18		Line 36 x Line 38	$39,532,703		$36,925,606
42	Less: Net Cost of Removal/(Salvage)		Line 32 x Cost of Removal Rate	($5,993,779)		
43	Less: Retired Plant		Line 33	($7,949,278)		
44	Book Depreciation Reserve 08/31/18		Sum of Line 40 through Line 43	$387,039,467		

1/ 3 year average retirement over plant addition in service FY 15 ~ FY17 6.87% Retirements
2/ 3 year average Cost of Removal over plant addition in service FY 15 ~ FY17 5.18% COR

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 6-GAS
Page 2 of 5

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

The Narragansett Electric Company
d/b/a National Grid
Gas ISR Depreciation Expense

Line No		Description		Reference	Amount	Less non-ISR eligible Plant	ISR Amount
					(a)	(b)	(c)
1		Rate Year Depreciation Expense 12 Months Ended 08/31/19:					
2		Total Utility Plant 08/31/18		Page 1, Line 28 + Line 32 + Line 33	$1,532,001,694	($77,133,057)	$1,454,868,637
3		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
4		Depreciable Utility Plant 08/31/18		Line 2 + Line 3	$1,223,486,969		$1,146,353,912
5							
6		Plus: Added Plant 12 Months Ended 08/31/19		Schedule 11-GAS, Page 3, Line 35	$114,477,000	($1,348,000)	$113,129,000
7		Less: Depreciable Retired Plant	1/	Line 6 x Retirement rate	($7,864,570)	$92,608	($7,771,962)
8							
9		Depreciable Utility Plant 08/31/19		Sum of Line 4 through Line 7	$1,330,099,399	($78,388,449)	$1,251,710,950
10							
11		Average Depreciable Plant for Rate Year Ended 08/31/19		(Line 4 + Line 9)/2	$1,276,793,184		$1,199,032,431
12							
13		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
14							
15		Book Depreciation Reserve 08/31/18		Page 1, Line 44	$387,039,467		$0
16		Plus: Book Depreciation Expense		Line 11 x Line 13	$38,950,409		$35,851,070
17		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
18		Less: Net Cost of Removal/(Salvage)	2/	Line 6 x Cost of Removal Rate	($5,929,909)		$0
19		Less: Retired Plant		Line 7	($7,864,570)		$0
20		Book Depreciation Reserve 08/31/19		Sum of Line 15 through Line 19	$412,381,898		$36,037,570
21							
22		Rate Year Depreciation Expense 12 Months Ended 08/31/20:					
23		Total Utility Plant 08/31/19		Line 2 + Line 6 + Line 7	$1,638,614,124	($78,388,449)	$1,560,225,675
24		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
25		Depreciable Utility Plant 08/31/19		Line 23 + Line 24	$1,330,099,399		$1,251,710,950
26							
27		Plus: Added Plant 12 Months Ended 08/31/20		Schedule 11-GAS, Page 5, Line 11(i)	$21,017,630	($750,000)	$20,267,630
28		Less: Depreciable Retired Plant	1/	Line 27 x Retirement rate	($1,443,911)	$51,525	($1,392,386)
29							$0
30		Depreciable Utility Plant 08/31/20		Sum of Line 25 through Line 28	$1,349,673,118	($79,086,924)	$1,270,586,194
31							
32		Average Depreciable Plant for Rate Year Ended 08/31/20		(Line 25 + Line 30)/2	$1,339,886,258		$1,261,148,572
33							
34		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
35							
36		Book Depreciation Reserve 08/31/20		Line 20	$412,381,898		$0
37		Plus: Book Depreciation Expense		Line 32 x Line 34	$40,875,154		$37,708,342
38		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
39		Less: Net Cost of Removal/(Salvage)	2/	Line 27 x Cost of Removal Rate	($1,088,713)		$0
40		Less: Retired Plant		Line 28	($1,443,911)		$0
41		Book Depreciation Reserve 08/31/20		Sum of Line 36 through Line 40	$450,910,927		$37,894,842
42							
43		Rate Year Depreciation Expense 12 Months Ended 08/31/21:					
44		Total Utility Plant 08/31/20		Line 23 + Line 27 + Line 28	$1,658,187,843	($79,086,924)	$1,579,100,919
45		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
46		Depreciable Utility Plant 08/31/20		Line 44 + Line 45	$1,349,673,118		$1,270,586,194
47							
48		Plus: Added Plant 12 Months Ended 08/31/21		Schedule 11-GAS, Page 5, Line 11(l)	$21,838,436	($750,000)	$21,088,436
49		Less: Depreciable Retired Plant	1/	Line 48 x Retirement rate	($1,500,301)	$51,525	($1,448,776)
50							
51		Depreciable Utility Plant 08/31/21		Sum of Line 46 through Line 49	$1,370,011,253	($79,785,399)	$1,290,225,854
52							
53		Average Depreciable Plant for Rate Year Ended 08/31/21		(Line 46 + Line 51)/2	$1,359,842,185		$1,280,406,024
54							
55		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
56							
57		Book Depreciation Reserve 08/31/20		Line 41	$450,910,927		$0
58		Plus: Book Depreciation Expense		Line 53 x Line 55	$41,483,938		$38,284,140
59		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
60		Less: Net Cost of Removal/(Salvage)	2/	Line 48 x Cost of Removal Rate	($1,131,231)		$0
61		Less: Retired Plant		Line 49	($1,500,301)		$0
62		Book Depreciation Reserve 08/31/21		Sum of Line 57 through Line 61	$489,949,834		$38,470,640
63							
64	1/	3 year average retirement over plant addition in service FY 15 ~ FY17		0.0687	Retirements		
65	2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17		0.0518	COR		
66							
67		Book Depreciation RY2		Line 37 (a) + Line 38 (b)			$41,061,654
68		Less: General Plant Depreciation (assuming add=retirement)		Page 10, Line 79(f)			($748,271)
69		Plus: Comm Equipment Depreciation		Page 10, Line 73 + Line 74			$32,079
70		Total					$40,345,462
71		7 Months					x7/12
72		FY 2020 Depreciation Expense					$23,534,853
73							
74		Book Depreciation RY3		Line 58 (a) + Line 59 (b)			$41,670,438
75		Less: General Plant Depreciation		Page 10, Line 79(f)			($748,271)
76		Plus: Comm Equipment Depreciation		Page 10, Line 73 + Line 74			$32,079
77		Total					$40,954,246
78		FY 2021 Depreciation Expense		5 Months of RY 2 and 7 Months of RY 3			$40,700,586

The Narragansett Electric Company
d/b/a National Grid
FY 2021 ISR Property Tax Recovery Adjustment
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		End of FY 2018	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2019**
1	Plant In Service	$1,195,705	$92,263	$24,845	$117,108		($6,844)		$1,305,969
2	Accumulated Depr	$414,713				$40,858	($6,844)	($6,123)	$442,604
3	Net Plant	$780,992							$863,364
4	Property Tax Expense	$22,678							$23,283
5	Effective Prop tax Rate	2.90%							2.70%
		End of FY 2019	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2020**
6	Plant In Service	$1,305,969	$154,552	$19,341	$173,893		($14,754)		$1,465,108
7	Accumulated Depr	$442,604				$41,650	($14,754)	($7,910)	$461,590
8	Net Plant	$863,364							$1,003,518
9	Property Tax Expense	$23,283							$28,640
10	Effective Prop tax Rate	2.70%							2.85%
		End of FY 2020	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2021**
11	Plant In Service	$1,465,108	$148,107	$24,845	$172,951		($20,635)		$1,617,424
12	Accumulated Depr	$461,590				$46,376	($20,635)	($15,619)	$471,711
13	Net Plant	$1,003,518							$1,145,712
14	Property Tax Expense	$28,640							$30,897
15	Effective Prop tax Rate	2.85%							2.70%

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Cumulative Increm. ISR Prop. Tax for FY2018				**Cumulative Increm. ISR Prop. Tax for FY2019 1st 5 month**						
16	Incremental ISR Additions		$97,810				$92,263					
17	Book Depreciation: base allowance on ISR eligible plant		($24,356)				($24,356)					
18	Book Depreciation: current year ISR additions		($1,246)				($1,449)					
19	COR		$8,603				$11,583					
20	Net Plant Additions		$80,811				$78,041					
21	RY Effective Tax Rate		3.06%				3.06%					
22	ISR Property Tax Recovery on FY 2014 vintage investment			$194		5 month	1.27%	$76				
23	ISR Property Tax Recovery on FY 2015 vintage investment			$1,311				$508				
24	ISR Property Tax Recovery on FY 2016 vintage investment			$1,819				$709				
25	ISR Property Tax Recovery on FY 2017 vintage investment			$1,799				$714				
26	ISR Property Tax Recovery on FY 2018 vintage investment			$2,469				$989				
27	ISR Property Tax Recovery on FY 2019 vintage investment							$993				
28	Total Property Tax due to ISR			$7,592				$3,989				
29	ISR Year Effective Tax Rate	2.90%				2.70%						
30	RY Effective Tax Rate	3.06%	-0.15%			3.06%	-0.36%					
31	RY Effective Tax Rate 5 mos for FY 2019		-0.15%			5 month	-0.15%					
32	RY Net Plant times 5 m 7 month	$458,057 * -0.15%		($694)		$458,057 * -0.15%		($684)				
33	FY 2014 Net Adds time 7 month	$6,343 * -0.15%		($10)		$5,950 * -0.15%		($9)				
34	FY 2015 Net Adds time 7 month	$42,913 * -0.15%		($65)		$39,920 * -0.15%		($60)				
35	FY 2016 Net Adds times ISR Year Effective Tax	$59,527 * -0.15%		($90)		$55,693 * -0.15%		($83)				
36	FY 2017 Net Adds times ISR Year Effective Tax	$58,883 * -0.15%		($89)		$56,076 * -0.15%		($84)				
37	FY 2018 Net Adds times ISR Year Effective Tax	$80,810 * -0.15%		($122)		$77,664 * -0.15%		($116)				
38	FY 2019 Net Adds times ISR Year Effective Tax rate					$78,041 * -0.15%		($117)				
39	Total Property Tax due to rate differential			($1,071)				($1,152)				

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
40	Total ISR Property Tax Recovery			$6,521				$2,837				

The Narragansett Electric Company
d/b/a National Grid
FY 2021 ISR Property Tax Recovery Adjustment

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Cumulative Increm. ISR Prop. Tax for FY2019		7 months		Cumulative Increm. ISR Prop. Tax for FY2020				Cumulative Increm. ISR Prop. Tax for FY2021		
41	Incremental ISR Additions		($914)				$115,728				148,107	
42	Book Depreciation: base allowance on ISR eligible plant		$0				$0				$0	
43	Book Depreciation: current year ISR additions		($7)				($1,571)				(1,928)	
44	COR		$5,627				$4,805				14,506	
45	Net Plant Additions		$4,705				$118,961				$160,685	
46												
47	RY Effective Tax Rate		2.92%				2.96%				3.02%	
48	Property Tax Recovery on Growth and non-ISR 7 mos		1.70%	$0				($604)				($1,249)
49	ISR Property Tax Recovery on FY 2018 Net Incremental			$118				$212				$223
50	ISR Property Tax Recovery on FY 2019 Net Incremental			$80				$139				$141
51	ISR Property Tax Recovery on FY 2020 Net Incremental							$3,518				$3,499
52	ISR Property Tax Recovery on FY 2021 vintage investment											$4,855
53	ISR Year Effective Tax Rate	2.70%				2.85%				2.70%		
54	RY Effective Tax Rate	2.92%	-0.22%			2.96%	-0.10%			3.02%	-0.32%	
55	RY Effective Tax Rate 7 mos for FY 2019		-0.13% 7 mos				-0.10%				-0.32%	
56	RY Net Plant times Rate 7 month	$919,892 * -0.13%		($1,203)		$908,586 * -0.1%		($939)		$889,353 * -0.32%		($2,886)
57	Growth and non-ISR Incremental times rate difference			$0		($20,407) * -0.1%		$21		($41,336) * -0.32%		$134
58	FY 2018 Net Incremental times rate difference	$6,934 * -0.13%		($9)		$7,156 * -0.1%		($7)		$7,378 * -0.32%		($24)
59	FY 2019 Net Incremental times rate difference	$4,705 * -0.13%		($6)		$4,692 * -0.1%		($5)		$4,678 * -0.32%		($15)
60	FY 2020 Net Incremental times rate difference					$118,961 * -0.1%		($123)		$115,818.93 * -0.32%		($376)
61	FY 2021 Net Adds times rate difference									$160,685 * -0.32%		($521)
62	Total Property Tax due to rate differential			($1,218)				($1,053)				($3,688)
63	Total ISR Property Tax Recovery			($1,138)				$2,212				$3,781

Line Notes

1(a) - 5(h) Docket No. 4781 Attachment MAL-2, Page 10 of 13, 1(a) to 5(h)
6(a) - 10(a) Per Line 1(h) ~ 5(h)
6(b) Page 5 of 12 , Line 1 ,Col (c)÷1000
6(c) Docket No. 4916, Revised Section 3, Att. 1R, P.15, L.7(c)
6(d) Line 6(b) + Line 6(c)
6(f) Page 5 of 12 , Line 7 ,Col (c)÷1000
6(h) Line 6(a) + (d) + (f)
7(e) As approved in RIPUC Docket No. 4996
7(f) =6(f)
7(g) Page 5 of 12 , Line 4 ,Col (c)÷1000
7(h) Line 7(a) + (e) + (f) + (g)
8(h) Line 6(h) - 7(h)
9(h) Docket No. 4916, Revised Section 3, Att. 1R, P.15, L.10(h)
10(h) Line 9(h) ÷ 8(h)
11(a) - 15(a) Per Line 6(h) ~ 10(h)
11(b) Page 5 of 12 , Line 1 ,Col (d)÷1000
11(c) Line 1(c) - Estimated based on FY2019 actual non-ISR addition
11(d) Line 11(b) + Line 11(c)
11(f) Page 5 of 12 , Line 7 ,Col (d)÷1000
11(h) Line 11(a) + (d) + (f)
12(e) As approved in RIPUC Docket No. 4996
12(f) =11(f)
12(g) - Page 5 of 12 , Line 4 ,Col (d)÷1000
12(h) Line 12(a) + (e) + (f) + (g)
13(h) Line 11(h) - 12(h)
14(h) Line 13(h) x 15(h)

Line Notes

15(h) Line 10(a) - Estimated based on FY2019 actual property rate
16(a) - 40(g) Docket No. 4781 Attachment MAL-1, Page 29 of 35, 82(e) to 107(k)
41(a) - 63(c) Docket No. 4781 Attachment MAL-2, Page 11 of 13, 31(a) to 50(c)
41(f) As approved in RIPUC Docket No. 4996
42(f) FY20 depreciation is reflected in the NBV at 56(e)
43(f) As approved in RIPUC Docket No. 4996
44(f) As approved in RIPUC Docket No. 4996
45(f) Sum of Lines 41(f) through 44(f)
47(f) =Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1, Sch 1-G, P2, L15, Col (c) ÷ 56(e)
48(g) Line 47(f) x Line 57(e)
49(g) Line 47(f) x Line 58(e)
50(g) Line 47(f) × 59(e)
51(g) Line 47(f) × 60(e)
53(e) =10(h)
54(e) =47(f)
54(f) 53(e) -54(e)
55(f) =54(f)
56(e) =Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1: 56(a) × 5÷12 + (Sch 6-G, P2, L30 - L41 + P3, L5(d) - P5, L4(d) - Sch 5-G, P1, L1(e) - L1(g)) × 7÷12000
56(g) 56(e) ×55(f)
57(e) = - Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1: Sch 11-G, P5, L3(e)+L3(g)+L7(e)+L7(g)
57(g) 57(e) ×55(f)
58(e) As approved in RIPUC Docket No. 4996
58(g) =58(e) ×55(f)
59(e) As approved in RIPUC Docket No. 4996
59(g) =59(e) ×55(f)
60(e) =45(f)
60(g) =60(e) ×55(f)
62(g) sum of 56(g) through 61(g)
63(g) sum of 48(g) through 51(g) + 62(g)

Line Notes

41(j) Page 2 of 12, Line 4(a) ÷1000
42(j) FY21 depreciation is reflected in the NBV at 56(i)
43(j) - Page 2 of 12, Line 12(a) ÷1000
44(j) Page 2 of 12, Line 7(a) ÷1000
45(j) Sum of Lines 41(j) through 44(j)
47(j) =Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1, Sch 1-G, P2, L15, Col (c) ÷ 56(i)
48(k) Line 47(j) x Line 57(i)
49(k) Line 47(j) x Line 58(i)
50(k) Line 47(j) x Line 59(i)
51(k) Line 47(j) x Line 60(i)
52(k) Line 47(j) x Line 61(i)
53(i) =15(h)
54(i) =47(j)
54(j) 53(i)-54(i)
55(j) =54(j)
56(i) =Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att.1, Sch 6-G: (P2, L30 - L41 + P3, L5(d) - P5, L4(d) - Sch 5-G, P1, L1(e) - L1(g)) × 5÷12000+(P2, L51 - L62 + P3, L5(d) - P5, L4(d) - Sch 5-G, P1, L1(e) - L1(g)- L1(i)) × 7÷12000
56(k) 56(i)×55(j)
57(i) = - Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1: Sch 11-G, P5, L3(h)+L3(j)+L7(h)+L7(j)
57(k) 57(i)×55(j)
58(i) As approved in RIPUC Docket No. 4996
58(k) =58(i)×55(j)
59(i) As approved in RIPUC Docket No. 4996
59(k) =59(i)×55(j)
60(i) As approved in RIPUC Docket No. 4996
60(k) =60(i)×55(j)
61(i) 45(j)
61(k) =61(i)×55(j)
62(k) sum of 56(k) through 61(k)
63(k) sum of 48(k) through 52(k) + 62(k)

28

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement updated
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			Test Year July 2016 - June 2017			Jul & Aug 2017	12 Mths Aug 31 2018	12 Mths Aug 31 2019	12 Mths Aug 31 2020
1	Total Base Rate Plant DIT Provision		$29,439,421			$5,223,437	$20,453,237	$16,078,372	$5,085,206
2	Excess DIT amortization					$0	$0	($1,470,238)	($1,470,238)
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2018	FY 2019	FY 2020	FY 2021
3	Total Base Rate Plant DIT Provision					$24,514,347	$17,043,594	$8,195,454	$5,167,632
4	Incremental FY 18	$2,507,039	$2,560,766	$1,773,289	$1,823,824	$2,507,039	$53,728	($787,477)	$50,535
5	Incremental FY 19	$0	$1,090,524	$1,085,911	$1,081,431	$0	$1,090,524	($4,613)	($4,480)
6	Incremental FY 20	$0	$0	$18,306,860	$18,169,033	$0	$0	$18,306,860	($137,827)
7	Incremental FY 21				$29,664,144				$29,664,144
8	TOTAL Plant DIT Provision	$2,507,039	$3,651,291	$21,166,061	$50,738,432	$27,021,386	$18,187,846	$25,710,224	$34,740,003
9	NOL (Utilization)					$6,051,855	($1,091,119)	($2,402,039)	($2,653,232)
10	Lesser of NOL or DIT Provision					$6,051,855	($1,091,119)	($2,402,039)	($2,653,232)

Line Notes:

1(e) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 3 plus Line 4
1(f) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 7
1(g) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 50
1(h) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 41
1(i) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 51
2 RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 52

3 Col (e) = Line 1(b) × 25% + Line 1(e) + Line 1(f) × 7/12; Col (f) = Line 1(f) × 5/12 + Line 1(g) × 7/12 + Line (2(f) x 5/12 + Line 2(g) × 7/12;

4(a)-7(d) Cumulative DIT plus Deferred Income Tax (Page 2, Line 16 + Line 18; Page 5, Line 16; Page 8, Line 16; Page 12, Line 16)
4(e)-7(h) Year over year change in cumulative DIT shown in Cols (a) through (d)
8 Sum of Lines 3 through 7
9 Col (e)(f) = Docket No. 4781 FY19 ISR Rec, Att. MAL-2, P.6, L.10; Col (g)= Docket no. 4916, R.S. 3, Att. 1R, P.11, L.10(c); Col(h) = Per Tax Department
10 Lesser of Line 8 or Line 9

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Gas ISR Plan Revenue Requirement updated
Calculation of Weighted Average Cost of Capital

Line No.						
1	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 35% income tax rate effective April 1, 2013					
2		(a)	(b)	(c)	(d)	(e)
3		Ratio	Rate	Weighted Rate	Taxes	Return
4	Long Term Debt	49.95%	5.70%	2.85%		2.85%
5	Short Term Debt	0.76%	0.80%	0.01%		0.01%
6	Preferred Stock	0.15%	4.50%	0.01%		0.01%
7	Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
8		100.00%		7.54%	2.51%	10.05%
9						
10	(d) - Column (c) x 35% divided by (1 - 35%)					
11						
12						
13	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 21% income tax rate effective January 1, 2018					
14		(a)	(b)	(c)	(d)	(e)
15		Ratio	Rate	Weighted Rate	Taxes	Return
16	Long Term Debt	49.95%	5.70%	2.85%		2.85%
17	Short Term Debt	0.76%	0.80%	0.01%		0.01%
18	Preferred Stock	0.15%	4.50%	0.01%		0.01%
19	Common Equity	49.14%	9.50%	4.67%	1.24%	5.91%
20		100.00%		7.54%	1.24%	8.78%
21	(d) - Column (c) x 21% divided by (1 - 21%)					
22						
23	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4770 effective September 1, 2018					
24		(a)	(b)	(c)	(d)	(e)
25		Ratio	Rate	Weighted Rate	Taxes	Return
26	Long Term Debt	48.35%	4.98%	2.41%		2.41%
27	Short Term Debt	0.60%	1.76%	0.01%		0.01%
28	Preferred Stock	0.10%	4.50%	0.00%		0.00%
29	Common Equity	50.95%	9.28%	4.73%	1.26%	5.99%
30		100.00%		7.15%	1.26%	8.41%
31	(d) - Column (c) x 21% divided by (1 - 21%)					
32						
33	FY18 Blended Rate		Line 8(e) × 75% + Line 20(e) × 25%			9.73%
34						
35	FY19 Blended Rate		Line 20 x 5 ÷ 12 + Line 30 x 7 ÷ 12			8.56%

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Investment Forecast Update
Annual Revenue Requirement Summary

Line No.		Approved Fiscal Year 2021 (a)	Fiscal Year 2022 (b)	As filed 2022 (c)
	Operation and Maintenance Expenses			
1	Forecasted Gas Operation and Maintenance Expense	$0	$0	$0
	Capital Investment:			
2	Actual Revenue Requirement on FY 2018 Incremental Capital Included in ISR Rate Base	$676,445	$690,881	$690,881
3	Actual Revenue Requirement on FY 2019 Incremental Capital Included in ISR Rate Base	$292,352	$291,583	$291,583
4	Actual Revenue Requirement on FY 2020 Incremental Capital Included in ISR Rate Base	$9,556,813	$8,718,700	$8,718,700
5	Forecasted Revenue Requirement on FY 2021 Capital Included in ISR Rate Base	$7,524,753	$11,946,762	$15,098,354
6	Forecasted Revenue Requirement on FY 2022 Capital Included in ISR Rate Base		$6,464,832	$6,464,832
7	Total Capital Investment Revenue Requirement	$18,050,363	$28,112,759	$31,264,350
8	FY 2021 Property Tax Recovery Adjustment	$4,711,167		
9	FY 2022 Property Tax Recovery Adjustment		$7,386,066	$8,261,429
10	**Total Capital Investment Component of Revenue Requirement**	**$22,761,529**	**$35,498,825**	**$39,525,779**
11	**Total Fiscal Year Revenue Requirement**	**$22,761,529**	**$35,498,825**	**$39,525,779**
12	**Incremental Fiscal Year Rate Adjustment**		**$12,737,295**	($4,026,954)

Column Notes:
(a) RIPUC Docket No. 4996, Revised Section 3, Attachment 1R, Page 1 of 22, Column (b)
(c) RIPUC Docket No. 5099, Section 3, Attachment MAL-1, Page 1 of 25, Column (b)

Line Notes for Columns (b) & (c) only:
1~5 RIPUC Docket No. 5099, Section 3, Attachment MAL-1, Page 1 of 25, Column (b), Lines 1 through 5
6 Page 5 of 12, Line 29, Col. (a) and Col. (b)
7 Sum of Lines 2 through Line 6
9 Page 11 of 12, Line 55, Column (k) × 1,000
10 Sum of Line 7 through Line 9
11 Line 1 + Line 10
12(b) Line 11 Col (b) - Line 11 Col (a)
12(c) Line 11 Col (b) - Line 11 Col (c)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Investment Forecast Update
FY 2022 Revenue Requirement FY 2021 Forecasted Incremental Gas Capital Investment

Line No.				Fiscal Year 2021 (a)	Fiscal Year 2022 (b)	Fiscal Year 2023 (c)
	Depreciable Net Capital Included in ISR Rate Base					
1	Total Allowed Capital Included in ISR Rate Base in Current Year	Page 5 of 12 , Line 3 ,Col (d)		$148,106,599	$0	$0
2	Retirements	Page 5 of 12 , Line 9 ,Col (d)	1/	$19,158,383	$0	$0
3	Net Depreciable Capital Included in ISR Rate Base	Year 1 = Line 1 - Line 2; then = Prior Year Line 3		$128,948,216	$128,948,216	$128,948,216
	Change in Net Capital Included in ISR Rate Base					
4	Capital Included in ISR Rate Base	Line 1		$148,106,599	$0	$0
5	Depreciation Expense	Page 9 of 12, Line 78(c)		$40,700,586	$0	$0
6	Incremental Capital Amount	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$107,406,012	$107,406,012	$107,406,012
7	Cost of Removal	Page 5 of 12 , Line 6 ,Col (d)		$14,505,886	$14,505,886	$14,505,886
8	**Net Plant Amount**	**Line 6 + Line 7**		**$121,911,898**	**$121,911,898**	**$121,911,898**
	Deferred Tax Calculation:					
9	Composite Book Depreciation Rate	Page 7 of 12, Line 86(e)	1/	2.99%	2.99%	2.99%
10	Tax Depreciation	Year 1 =Page 3 of 12, Line 21, Col (a); then = Page 3 of 12, Col (d)		$143,185,602	$1,573,835	$1,455,672
11	Cumulative Tax Depreciation	Year 1 = Line 10; then = Prior Year Line 11 + Current Year Line 10		$143,185,602	$144,759,437	$146,215,110
12	Book Depreciation	Year 1 = Line 3 × Line 9 × 50% ; then = Line 3 × Line 9		$1,927,776	$3,855,552	$3,855,552
13	Cumulative Book Depreciation	Year 1 = Line 12; then = Prior Year Line 13 + Current Year Line 12		$1,927,776	$5,783,328	$9,638,879
14	Cumulative Book / Tax Timer	Line 11 - Line 13		$141,257,826	$138,976,110	$136,576,230
15	Effective Tax Rate			21.00%	21.00%	21.00%
16	Deferred Tax Reserve	Line 14 × Line 15		$29,664,144	$29,184,983	$28,681,008
17	Add: FY 2021 Federal NOL utilization	Page 5 of 12 , Line 12 ,Col (d)		($7,598,182)	($7,598,182)	($7,598,182)
18	Net Deferred Tax Reserve before Proration Adjustment	Line 16 + Line 17		$22,065,961	$21,586,801	$21,082,826
	ISR Rate Base Calculation:					
19	Cumulative Incremental Capital Included in ISR Rate Base	Line 8		$121,911,898	$121,911,898	$121,911,898
20	Accumulated Depreciation	- Line 13		($1,927,776)	($5,783,328)	($9,638,879)
21	Deferred Tax Reserve	- Line 18		($22,065,961)	($21,586,801)	($21,082,826)
22	Year End Rate Base before Deferred Tax Proration	Sum of Lines 19 through 21		$97,918,161	$94,541,770	$91,190,193
	Revenue Requirement Calculation:					
23	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = 0; then Average of (Prior + Current Year Line 22)			$96,229,966	$92,865,982
24	Proration Adjustment	Year 1 =0; then = Page 4 of 12, Line 41, Col (j) and Col. (k)			($20,567)	($21,632)
25	Average ISR Rate Base after Deferred Tax Proration	Line 23 + Line 24			$96,209,399	$92,844,350
26	Pre-Tax ROR	Page 12 of 12, Line 30, Column (e)			8.41%	8.41%
27	Return and Taxes	Line 25 × Line 26			$8,091,210	$7,808,210
28	Book Depreciation	Line 12			$3,855,552	$3,855,552
29	**Annual Revenue Requirement**	**Sum of Lines 27 through 28**		**N/A**	**$11,946,762**	**$11,663,761**

1/ 2.99%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4770, effective on Sep 1, 2018

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Investment Forecast Update
Calculation of Tax Depreciation and Repairs Deduction on FY 2021 Incremental Capital Investments

Line No.				Fiscal Year 2021 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 2 of 12, Line 1		$148,106,599
2	Capital Repairs Deduction Rate	Per Tax Department	1/	85.28%
3	Capital Repairs Deduction	Line 1 × Line 2		$126,305,307
	Bonus Depreciation			
4	Plant Additions	Line 1		$148,106,599
5	Less Capital Repairs Deduction	Line 3		$126,305,307
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$21,801,292
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%
8	Plant Eligible for Bonus Depreciation	Line 6 × Line 7		$0
9	Bonus Depreciation Rate ()	Per Tax Department		0.00%
10	Bonus Depreciation Rate ()	Per Tax Department		0.00%
11	Total Bonus Depreciation Rate	Line 9 + Line 10		0.00%
12	Bonus Depreciation	Line 8 × Line 11		$0
	Remaining Tax Depreciation			
13	Plant Additions	Line 1		$148,106,599
14	Less Capital Repairs Deduction	Line 3		$126,305,307
15	Less Bonus Depreciation	Line 12		$0
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$21,801,292
17	20 YR MACRS Tax Depreciation Rates	IRS Publication 946		3.75%
18	Remaining Tax Depreciation	Line 16 × Line 17		$817,548
19	FY21 tax (gain)/loss on retirements	Per Tax Department	2/	1,556,861
20	Cost of Removal	Page 2 of 12, Line 7		$14,505,886
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19 & 20		$143,185,602

20 Year MACRS Depreciation

(b)	(c)	(d)	(e)
MACRS basis:		$21,801,292	
		Annual	Cumulative
Fiscal Year			
2021	3.75%	$817,548	$143,185,602
2022	7.22%	$1,573,835	$144,759,437
2023	6.68%	$1,455,672	$146,215,110
2024	6.18%	$1,346,666	$147,561,775
2025	5.71%	$1,245,508	$148,807,283
2026	5.29%	$1,152,198	$149,959,481
2027	4.89%	$1,065,647	$151,025,129
2028	4.52%	$985,854	$152,010,983
2029	4.46%	$972,774	$152,983,757
2030	4.46%	$972,556	$153,956,312
2031	4.46%	$972,774	$154,929,086
2032	4.46%	$972,556	$155,901,642
2033	4.46%	$972,774	$156,874,415
2034	4.46%	$972,556	$157,846,971
2035	4.46%	$972,774	$158,819,744
2036	4.46%	$972,556	$159,792,300
2037	4.46%	$972,774	$160,765,074
2038	4.46%	$972,556	$161,737,629
2039	4.46%	$972,774	$162,710,403
2040	4.46%	$972,556	$163,682,959
2041	2.23%	$486,387	$164,169,345
	100.00%	$21,801,292	

1/ Capital Repairs percentage is based on a three-year average of FYs 2017, 2018 and 2019 capital repairs rates.
2/ FY 2021 estimated tax loss on retirements is tax department estimate

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Investment Forecast Update
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investments

Line No.	**Deferred Tax Subject to Proration**		(a) FY22	(b) FY23
1	Book Depreciation	Page 2 of 12 , Line 12 ,Col (b) and Col (c)	$3,855,552	$3,855,552
2	Bonus Depreciation	Page 3 of 12 , Line 12 ,Col (a)	$0	
3	Remaining MACRS Tax Depreciation	Page 3 of 12 , Col (d)	($1,573,835)	($1,455,672)
4	FY21 tax (gain)/loss on retirements	Page 3 of 12 , Line 19 ,Col (a)	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$2,281,716	$2,399,879
6	Effective Tax Rate		21%	21%
7	Deferred Tax Reserve	Line 5 × Line 6	$479,160	$503,975
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	Page 3 of 12 , Line 3 ,Col (a)		
9	Cost of Removal	Page 2 of 12 , Line 7 ,Col (a)		
10	Book/Tax Depreciation Timing Difference at 3/31/2021			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		
12	Effective Tax Rate			
13	Deferred Tax Reserve	Line 11 × Line 12		
14	Total Deferred Tax Reserve	Line 7 + Line 13	$479,160	$503,975
15	Net Operating Loss	- Page 2 of 12 , Line 17 ,Col (a)		
16	Net Deferred Tax Reserve	Line 14 + Line 15	$479,160	$503,975
	Allocation of FY 2021 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$2,281,716	$2,399,879
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$2,281,716	$2,399,879
20	Total FY 2021 Federal NOL	- Page 2 of 12 , Line 17 ,Col (a)÷21%		
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0	$0
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20	$0	$0
23	Effective Tax Rate		21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	$479,160	$503,975

	Proration Calculation	(h) Number of Days in Month	(i) Proration Percentage	(j) FY22	(k) FY23
26	April	30	91.78%	$36,648	$38,546
27	May	31	83.29%	$33,257	$34,979
28	June	30	75.07%	$29,975	$31,527
29	July	31	66.58%	$26,584	$27,960
30	August	31	58.08%	$23,192	$24,393
31	September	30	49.86%	$19,910	$20,941
32	October	31	41.37%	$16,519	$17,374
33	November	30	33.15%	$13,237	$13,923
34	December	31	24.66%	$9,846	$10,356
35	January	31	16.16%	$6,454	$6,789
36	February	28	8.49%	$3,391	$3,567
37	March	31	0.00%	$0	$0
38	Total	365		$219,014	$230,356
39	Deferred Tax Without Proration	Line 25		$479,160	$503,975
40	Average Deferred Tax without Proration	Line 39 × 0.5		$239,580	$251,987
41	Proration Adjustment	Line 38 - Line 40		($20,567)	($21,632)

Column Notes:
(i) Sum of remaining days in the year (Col (h)) divided by 365
(j) & (k) Current Year Line 25 ÷ 12 × Current Month Col (i)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Investment Forecast Update
FY 2018 - FY 2022 Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2018 (a)	Actual Fiscal Year 2019 (b)	Actual Fiscal Year 2020 (c)	Plan Fiscal Year 2021 (d)	Plan Fiscal Year 2022 (e)
	Capital Investment						
1	ISR-eligible Capital Investment	Col (a)=Docket No. 4678 FY18 Reconciliation Filing; Col (b)=Docket No. 4781 FY19 Reconciliation Filing; Col (c)=Docket No. 4916 FY20 Reconciliation Filing; Col (d)=Docket No. 4996 FY21 Plan Filing; Col(e)=Section 2, Table 1	$97,809,718	$92,263,000	$144,119,796	$148,106,599	$175,462,000
2	ISR-eligible Capital Additions included in Rate Base per RIPUC Docket No. 4770	Docket No. 4770 Schedule MAL-11-Gas Page 5, Col (a)=Lines 1(a) + 1(b); Col(b)=Lines 1(c) + 1(d); Col(c)= Line 1(e)	$93,177,000	$93,177,000	$38,823,750	$0	$0
3	Incremental ISR Capital Investment	Line 1 - Line 2	$4,632,718	($914,000)	$105,296,046	$148,106,599	$175,462,000
	Cost of Removal						
4	ISR-eligible Cost of Removal	Col (a) Docket No. 4678 FY 2018 ISR Reconciliation Filing; Col (b) Docket No. 4781 FY 2019 ISR Reconciliation Filing; Col (c) Docket No. 4916 FY 2020 ISR Reconciliation Filing; Col (d)=Docket No. 4996 FY21 Plan Filing; Col (e)=Section 2, Table 1	$8,603,224	$11,583,085	$10,161,508	$15,619,401	$4,684,000
5	ISR-eligible Cost of Removal in Rate Base per RIPUC Docket No. 4770	Schedule 6-GAS, Docket No. 4770: Col(a)=[P1]L23+L42×7÷12+Docket 4678 Page 2, Line 7x3÷12; Col(b)=[P1]L42×5÷12+[P2]L18×7÷12; Col (c)=[P2]L18×5÷12+L39×7÷12; Col (d)=[P2] L39×5÷12+L60×7÷12; Col (e)= [P2] L60×5÷12	$6,662,056	$5,956,522	$3,105,878	$1,113,515	$471,346
6	Incremental Cost of Removal	Line 4 - Line 5	$1,941,168	$5,626,564	$7,055,630	$14,505,886	$4,212,654
	Retirements						
7	ISR-eligible Retirements	Col (a) Docket No. 4678 FY 2018 ISR Reconciliation Filing; Col (b) Docket No. 4781 FY 2019 ISR Reconciliation Filing; Col (c) Docket No. 4916 FY 2020 ISR Reconciliation Filing; Col (d) Docket No. 4996 FY21 Plan Filing; Col(e)=FY22 Planned Investment x 3-year average actual retirement rate FY18 - FY20	$24,056,661	$6,531,844	$8,395,321	$20,635,188	$21,932,866
8	ISR-eligible Retirements per RIPUC Docket No. 4770	Schedule 6-GAS, Docket No. 4770: Col(a)=[P1]L24+L43×7÷12+ Docket 4678 Page 2, Line 2x3÷12; Col(b)=[P1]L43×5÷12+[P2]L19×7÷12; Col (c)=[P2]L19×5÷12+L40×7÷12; Col (d) = [P2]L40×5÷12+L61×7÷12; Col (e)= L61×5÷12	$11,997,233	$7,899,865	$4,119,186	$1,476,805	$625,125
9	Incremental Retirements	Line 7 - Line 8	$12,059,428	($1,368,021)	$4,276,135	$19,158,383	$21,307,741
	(NOL)/ NOL Utilization						
10	ISR (NOL)/NOL Utilization Per ISR	Page 6 of 12, Line 11	($6,051,855)	$1,091,119	$0	$0	$10,722,358
11	ISR NOL Utilization Per Docket 4770	Schedule 11-Gas Page 11, Docket No. 4770: Col (a)= L40×5÷12; Col (b) = L40×5÷12+L48×7÷12; Col (c) = P11,L48×5÷12+P12,L39×7÷12; Col (d) = P12,L39×5÷12+P12,L49×7÷12; Col (e)= P12,L49×5÷12	$0	$804,769	$3,063,059	$7,598,182	$4,157,771
12	Incremental (NOL)/NOL Utilization	Line 10 - Line 11	($6,051,855)	$286,350	($3,063,059)	($7,598,182)	$6,564,587

Note: The FY21 updated ISR capital investment of $163,726,000 is the sum of Line 1 and Line 4.

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Investment Forecast Update
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Test Year July 2016 - June 2017				Jul & Aug 2017	12 Mths Aug 31 2018	12 Mths Aug 31 2019	12 Mths Aug 31 2020	12 Mths Aug 31 2021
1	Total Base Rate Plant DIT Provision		$29,439,421				$5,223,437	$20,453,237	$16,078,372	$5,085,206	$7,746,916
2	Excess DIT amortization						$0	$0	($1,470,238)	($1,470,238)	($1,470,238)
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
3	Total Base Rate Plant DIT Provision						$24,514,347	$17,043,594	$8,195,454	$5,167,632	$2,615,283
4	Incremental FY 18	$2,507,039	$2,560,766	$1,773,289	$1,823,824	$1,874,066	$2,507,039	$53,728	($787,477)	$50,535	$50,242
5	Incremental FY 19	$0	$1,090,524	$1,085,911	$1,081,431	$1,077,072	$0	$1,090,524	($4,613)	($4,480)	($4,358)
6	Incremental FY 20	$0	$0	$18,484,445	$18,218,347	$17,924,604	$0	$0	$18,484,445	($266,098)	($293,743)
7	Incremental FY 21				$29,664,144	$29,184,983				$29,664,144	($479,160)
8	Incremental FY 22					$30,903,991					$30,903,991
9	TOTAL Plant DIT Provision	$2,507,039	$3,651,291	$21,343,646	$50,787,746	$80,964,717	$27,021,386	$18,187,846	$25,887,809	$34,611,732	$32,792,254
10	NOL (Utilization)						$6,051,855	($1,091,119)	$0	$0	($10,722,358)
11	Lesser of NOL or DIT Provision						$6,051,855	($1,091,119)	$0	$0	($10,722,358)

Line Notes:

1(b) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 2 of 23, Line 29, Col (e) minus Col (b)
1(f) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 3 plus Line 4
1(g) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 7
1(h) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 11 of 23, Line 50
1(i) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 41
1(j) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 51
1(k) RIPUC Docket Nos. 4770/4780 third rate year ends at Aug 31, 2021
2 RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-GAS, Page 12 of 23, Line 52
3 Col (f) = Line 1(b) × 25% + Line 1(f) + Line 1(g) × 7/12; Col (g) = Line 1(g) × 5/12 + Line 1(h) × 7/12 + Line (2(g) x 5/12 + Line 2(h) × 7/12; Col (h) = Line 1(h) × 5/12 + Line 1(i) × 7/12 + Line (2(h) x 5/12 + Line 2(i) × 7/12; Col (i) = Line 1(i) × 5/12 + Line 1(j) × 7/12 + Line (2(i) x 5/12 + Line 2(j) × 7/12;
4(a)-8(e) Cumulative DIT plus Deferred Income Tax (Page 2, Line 16 + Line 18; Page 5, Line 16; Page 8, Line 16; Page 12, Line 16; Page 15, Line 16)
4(f)-8(j) Year over year change in cumulative DIT shown in Cols (a) through (e)
9 Sum of Lines 3 through 8
10 Col (f)~(g) = Docket no. 4916 FY 20 ISR Rec, Att. MAL-1, p.19, L. 8; Col (h) ~Col (j) Per Tax Department
11 Lesser of Line 9 or Line 10

The Narragansett Electric Company
d/b/a National Grid
ISR Depreciation Expense per Rate Case RIPUC Docket No. 4770

Line	Account No.	Account Title	Test Year June 30, 2017 (a) 1/	ARO Adjustment (b)	Adjustments June 30, 2017 (c)	Adjusted Balance (d) = (a) + (b) + (c)	Proposed Rate (e)	Depreciation Expense (f) = (d) x (e)
		Intangible Plant						
1	302.00	Franchises And Consents	$213,499	$0	$0	$213,499	0.00%	$0
2	303.00	Misc. Intangible Plant	$25,427	$0	$0	$25,427	0.00%	$0
3	303.01	Misc. Int Cap Software	$19,833,570	$0	$9,991,374	$29,824,944	0.00%	$0
4								
5		Total Intangible Plant	$20,072,496	$0	$9,991,374	$30,063,870		$0
6								
7		Production Plant						
8								
9	304.00	Production Land Land Rights	$364,912	$0	$0	$364,912	0.00%	$0
10	305.00	Prod. Structures & Improvements	$2,693,397	$0	$0	$2,693,397	15.05%	$405,356
11	307.00	Production Other Power	$46,159	$0	$0	$46,159	7.16%	$3,305
12	311.00	Production LNG Equipment	$3,167,445	$0	$0	$3,167,445	11.40%	$361,089
13	320.00	Prod. Other Equipment	$1,106,368	$0	$0	$1,106,368	6.69%	$74,016
14								
15		Total Production Plant	$7,378,281	$0	$0	$7,378,281		$843,766
16								
17		Storage Plant						
18								
19	360.00	Stor. Land & Land Rights	$261,151	$0	$0	$261,151	0.00%	$0
20	361.03	Storage Structures Improvements	$3,385,049	$0	$0	$3,385,049	0.99%	$33,512
21	362.04	Storage Gas Holders	$4,606,338	$0	$0	$4,606,338	0.04%	$1,843
22	363.00	Stor. Purification Equipment	$13,891,210	$0	$0	$13,891,210	3.37%	$468,134
23								
24		Total Storage Plant	$22,143,748	$0	$0	$22,143,748		$503,488
25								
26		Distribution Plant						
27								
28	374.00	Dist. Land & Land Rights	$956,717	$0	$0	$956,717	0.00%	$0
29	375.00	Gas Dist Station Structure	$10,642,632	$0	$0	$10,642,632	1.15%	$122,390
30	376.00	Distribution Mains	$46,080,760	$0	$0	$46,080,760	3.61%	$1,663,515
31	376.03	Dist. River Crossing Main	$695,165	$0	$0	$695,165	3.61%	$25,095
32	376.04	Mains - Steel And Other - Sl	$4,190	$0	$0	$4,190	0.00%	$0
33	376.06	Dist. District Regulator	$14,213,837	$0	$0	$14,213,837	3.61%	$513,120
34	376.11	Gas Mains Steel	$57,759,572	$0	$0	$57,759,572	3.31%	$1,908,954
35	376.12	Gas Mains Plastic	$382,797,443	$0	$0	$382,797,443	2.70%	$10,316,391
36	376.13	Gas Mains Cast Iron	$5,556,209	$0	$0	$5,556,209	8.39%	$465,888
37	376.14	Gas Mains Valves	$222,104	$0	$0	$222,104	3.61%	$8,018
38	376.15	Propane Lines	$0	$0	$0	$0	3.61%	$0
39	376.16	Dist. Cathodic Protect	$1,569,576	$0	$0	$1,569,576	3.61%	$56,662
40	376.17	Dist. Joint Seals	$63,067,055	$0	$0	$63,067,055	4.63%	$2,920,005
41	377.00	T&D Compressor Sta Equipment	$248,656	$0	$0	$248,656	1.07%	$2,661
42	377.62	1/ 5360-Tanks ARO	$299	($299)	$0	$0	0.00%	$0
43	378.10	Gas Measure & Reg Sta Equipment	$19,586,255	$0	$0	$19,586,255	2.08%	$407,394
44	378.55	Gas M&Reg Sta Eqp RTU	$372,772	$0	$0	$372,772	6.35%	$23,671
45	379.00	Dist. Measure. Reg. Gs	$11,033,164	$0	$0	$11,033,164	2.22%	$244,936
46	379.01	Dist. Meas. Reg. Gs Eq	$1,399,586	$0	$0	$1,399,586	0.00%	$0
47	380.00	Gas Services All Sizes	$331,205,854	$0	$0	$331,205,854	3.05%	$10,101,779
48	381.10	Sml Meter& Reg Bare Co	$26,829,565	$0	$0	$26,829,565	1.76%	$472,200
49	381.30	Lrg Meter& Reg Bare Co	$15,779,214	$0	$0	$15,779,214	1.76%	$277,714
50	381.40	Meters	$9,332,227	$0	$0	$9,332,227	0.96%	$89,589
51	382.00	Meter Installations	$675,201	$0	$0	$675,201	3.66%	$24,712
52	382.20	Sml Meter& Reg Installation	$43,145,998	$0	$0	$43,145,998	3.66%	$1,579,144
53	382.30	Lrg Meter&Reg Installation	$2,524,025	$0	$0	$2,524,025	3.66%	$92,379
54	383.00	Dist. House Regulators	$937,222	$0	$0	$937,222	0.67%	$6,279
55	384.00	T&D Gas Reg Installs	$1,216,551	$0	$0	$1,216,551	1.56%	$18,978
56	385.00	Industrial Measuring And Regulating Station Equipment	$540,187	$0	$0	$540,187	4.18%	$22,580
57	385.01	Industrial Measuring And Regulating Station Equipment	$255,921	$0	$0	$255,921	0.00%	$0
58	386.00	Other Property On Customer Premises	$271,765	$0	$0	$271,765	0.23%	$625
59	386.02	Dist. Consumer Prem Equipment	$110,131	$0	$0	$110,131	0.00%	$0
60	387.00	Dist. Other Equipment	$930,079	$0	$0	$930,079	2.15%	$19,997
61	388.00	1/ ARO	$5,736,827	($5,736,827)	$0	$0	0.00%	$0
62								
63		Total Distribution Plant	$1,055,696,761	($5,737,126)	$0	$1,049,959,635	2.99%	$31,384,677
64								
65		General Plant						
66								
67	389.01	General Plant Land Lan	$285,357	$0	$0	$285,357	0.00%	$0
68	390.00	Structures And Improvements	$7,094,532	$0	$0	$7,094,532	3.12%	$221,349
69	391.01	Gas Office Furniture & Fixture	$274,719	$0	$0	$274,719	6.67%	$18,324
70	394.00	General Plant Tools Shop (Fully Dep)	$26,487	$0	$0	$26,487	0.00%	$0
71	394.00	General Plant Tools Shop	$5,513,613	$0	$0	$5,513,613	5.00%	$275,681
72	395.00	General Plant Laboratory	$221,565	$0	$0	$221,565	6.67%	$14,778
73	397.30	Communication Radio Site Specific	$387,650	$0	$0	$387,650	5.00%	$19,383
74	397.42	Communication Equip Tel Site	$63,481	$0	$0	$63,481	20.00%	$12,696
75	398.10	Miscellaneous Equipment (Fully Dep)	$1,341,386	$0	$0	$1,341,386	0.00%	$0
76	398.10	Miscellaneous Equipment	$2,789,499	$0	$0	$2,789,499	6.67%	$186,060
77	399.10	1/ ARO	$342,146	($342,146)	$0	$0	0.00%	$0
78								
79		Total General Plant	$18,340,436	($342,146)	$0	$17,998,289	4.16%	$748,271
80								
81		Grand Total - All Categories	$1,123,631,722	($6,079,273)	$9,991,374	$1,127,543,823	3.05%	$33,480,202
82							2.97%	
83		Other Utility Plant Assets						
84			Line 63		Total Distribution Plant	$1,049,959,635	2.99%	$31,384,677
85			Line 73 + Line 74		Communication Equipment	$451,132	7.11%	$32,079
86					Total ISR Tangible Plant	$1,050,410,767	2.99%	$31,416,756
					Non ISR Assets	$77,133,057		

Lines 1 through 81 - per RIPUC Docket No. 4770 Compliance filing dated August 16, 2018 , Compliance Attachment 2, Schedule 6-GAS, Pages 3 & 4

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

The Narragansett Electric Company
d/b/a National Grid
Gas ISR Depreciation Expense

Line No	Description		Reference	Amount	Less non-ISR eligible Plant	ISR Amount
				(a)	(b)	(c)
1	Total Company Rate Year Depreciation		Sum of Page 2, Line 16 and Line 17	$39,136,909		
2	Total Company Test Year Depreciation		Per Company Books	$33,311,851		
3	Less: Reserve adjustments		Page 4, Line 29, Col (b) + Col (c)	($15,649)		
4	Adjusted Total Company Test Year Depreciation Expense		Line 2 + Line 3	$33,296,202		
5	Depreciation Expense Adjustmen		Line 1 - Line 4	$5,840,707		
6						
7				Per Book		
8	Test Year Depreciation Expense 12 Months Ended 06/30/17:			Amount		
9	Total Gas Utility Plant 06/30/17		Page 4, Line 27, Col (d)	$1,405,994,678	($77,133,057)	$1,328,861,622
10	Less Non Depreciable Plant		Sum of Page 3, Line 5, Col (d) and Page 4, Line 25, Col (e)	($308,514,725)		($308,514,725)
11	Depreciable Utility Plant 06/30/17		Line 9 + Line 10	$1,097,479,953	($77,133,057)	$1,020,346,897
12						
13	Plus: Added Plant 2 Mos Ended 08/31/17		Schedule 11-GAS, Page 3, Line 4	$19,592,266		$19,592,266
14	Less: Retired Plant 2 Months Ended 08/31/17	1/	Line 13 x Retirement Rate	($1,345,989)		($1,345,989)
15	Depreciable Utility Plant 08/31/17		Line 11 + Line 13 + Line 14	$1,115,726,231	($77,133,057)	$1,020,346,897
16						
17	Average Depreciable Plant for Year Ended 08/31/17		(Line 11 + Line 15)/2	$1,106,603,092		$1,106,603,092
18						
19	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.38%		
20						
21	Book Depreciation Reserve 06/30/17		Page 5, Line 72, Col (d)	$357,576,825		$357,576,825
22	Plus: Book Depreciation Expense		Line 17 x Line 19	$6,233,864		$6,233,864
23	Less: Net Cost of Removal/(Salvage)	2/	Line 13 x Cost of Removal Rate	($1,014,879)		($1,014,879)
24	Less: Retired Plant		Line 14	($1,345,989)		($1,345,989)
25	Book Depreciation Reserve 08/31/17		Sum of Line 21 through Line 24	$361,449,821		
26						
27	Depreciation Expense 12 Months Ended 08/31/18					
28	Total Utility Plant 08/31/17		Line 9 + Line 13 + Line 14	$1,424,240,956	($77,133,057)	$1,347,107,900
29	Less Non Depreciable Plant		Line 10	($308,514,725)		($308,514,725)
30	Depreciable Utility Plant 08/31/17		Line 28 + Line 29	$1,115,726,231		$1,038,593,175
31						
32	Plus: Plant Added in 12 Months Ended 08/31/18		Schedule 11-GAS, Page 3, Line 11	$115,710,016		$115,710,016
33	Less: Plant Retired in 12 Months Ended 08/31/18		Line 32 x Retirement rate	($7,949,278)		($7,949,278)
34	Depreciable Utility Plant 08/31/18		Sum of Line 30 through Line 33	$1,223,486,969		$1,146,353,912
35						
36	Average Depreciable Plant for 12 Months Ended 08/31/18		(Line 30 + Line 34)/2	$1,169,606,600		$1,092,473,543
37						
38	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.38%		3.38%
39						
40	Book Depreciation Reserve 08/31/17		Line 25	$361,449,821		
41	Plus: Book Depreciation 08/31/18		Line 36 x Line 38	$39,532,703		$36,925,606
42	Less: Net Cost of Removal/(Salvage)		Line 32 x Cost of Removal Rate	($5,993,779)		
43	Less: Retired Plant		Line 33	($7,949,278)		
44	Book Depreciation Reserve 08/31/18		Sum of Line 40 through Line 43	$387,039,467		

1/ 3 year average retirement over plant addition in service FY 15 ~ FY17 6.87% Retirements
2/ 3 year average Cost of Removal over plant addition in service FY 15 ~ FY17 5.18% COR

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 6-GAS
Page 2 of 5

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Gas
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

The Narragansett Electric Company
d/b/a National Grid
Gas ISR Depreciation Expense

Line No		Description		Reference	Amount	Less non-ISR eligible Plant	ISR Amount
					(a)	(b)	(c)
1		Rate Year Depreciation Expense 12 Months Ended 08/31/19:					
2		Total Utility Plant 08/31/18		Page 1, Line 28 + Line 32 + Line 33	$1,532,001,694	($77,133,057)	$1,454,868,637
3		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
4		Depreciable Utility Plant 08/31/18		Line 2 + Line 3	$1,223,486,969		$1,146,353,912
5							
6		Plus: Added Plant 12 Months Ended 08/31/19		Schedule 11-GAS, Page 3, Line 35	$114,477,000	($1,348,000)	$113,129,000
7		Less: Depreciable Retired Plant	1/	Line 6 x Retirement rate	($7,864,570)	$92,608	($7,771,962)
8							
9		Depreciable Utility Plant 08/31/19		Sum of Line 4 through Line 7	$1,330,099,399	($78,388,449)	$1,251,710,950
10							
11		Average Depreciable Plant for Rate Year Ended 08/31/19		(Line 4 + Line 9)/2	$1,276,793,184		$1,199,032,431
12							
13		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
14							
15		Book Depreciation Reserve 08/31/18		Page 1, Line 44	$387,039,467		$0
16		Plus: Book Depreciation Expense		Line 11 x Line 13	$38,950,409		$35,851,070
17		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
18		Less: Net Cost of Removal/(Salvage)	2/	Line 6 x Cost of Removal Rate	($5,929,909)		$0
19		Less: Retired Plant		Line 7	($7,864,570)		$0
20		Book Depreciation Reserve 08/31/19		Sum of Line 15 through Line 19	$412,381,898		$36,037,570
21							
22		Rate Year Depreciation Expense 12 Months Ended 08/31/20:					
23		Total Utility Plant 08/31/19		Line 2 + Line 6 + Line 7	$1,638,614,124	($78,388,449)	$1,560,225,675
24		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
25		Depreciable Utility Plant 08/31/19		Line 23 + Line 24	$1,330,099,399		$1,251,710,950
26							
27		Plus: Added Plant 12 Months Ended 08/31/20		Schedule 11-GAS, Page 5, Line 11(i)	$21,017,630	($750,000)	$20,267,630
28		Less: Depreciable Retired Plant	1/	Line 27 x Retirement rate	($1,443,911)	$51,525	($1,392,386)
29							$0
30		Depreciable Utility Plant 08/31/20		Sum of Line 25 through Line 28	$1,349,673,118	($79,086,924)	$1,270,586,194
31							
32		Average Depreciable Plant for Rate Year Ended 08/31/20		(Line 25 + Line 30)/2	$1,339,886,258		$1,261,148,572
33							
34		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
35							
36		Book Depreciation Reserve 08/31/20		Line 20	$412,381,898		$0
37		Plus: Book Depreciation Expense		Line 32 x Line 34	$40,875,154		$37,708,342
38		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
39		Less: Net Cost of Removal/(Salvage)	2/	Line 27 x Cost of Removal Rate	($1,088,713)		$0
40		Less: Retired Plant		Line 28	($1,443,911)		$0
41		Book Depreciation Reserve 08/31/20		Sum of Line 36 through Line 40	$450,910,927		$37,894,842
42							
43		Rate Year Depreciation Expense 12 Months Ended 08/31/21:					
44		Total Utility Plant 08/31/20		Line 23 + Line 27 + Line 28	$1,658,187,843	($79,086,924)	$1,579,100,919
45		Less Non-Depreciable Plant		Page 1, Line 10	($308,514,725)		($308,514,725)
46		Depreciable Utility Plant 08/31/20		Line 44 + Line 45	$1,349,673,118		$1,270,586,194
47							
48		Plus: Added Plant 12 Months Ended 08/31/21		Schedule 11-GAS, Page 5, Line 11(l)	$21,838,436	($750,000)	$21,088,436
49		Less: Depreciable Retired Plant	1/	Line 48 x Retirement rate	($1,500,301)	$51,525	($1,448,776)
50							
51		Depreciable Utility Plant 08/31/21		Sum of Line 46 through Line 49	$1,370,011,253	($79,785,399)	$1,290,225,854
52							
53		Average Depreciable Plant for Rate Year Ended 08/31/21		(Line 46 + Line 51)/2	$1,359,842,185		$1,280,406,024
54							
55		Proposed Composite Rate %		Page 4, Line 17, Col (e)	3.05%		2.99%
56							
57		Book Depreciation Reserve 08/31/20		Line 41	$450,910,927		$0
58		Plus: Book Depreciation Expense		Line 53 x Line 55	$41,483,938		$38,284,140
59		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-GAS, Part VI, Page 6	$186,500		$186,500
60		Less: Net Cost of Removal/(Salvage)	2/	Line 48 x Cost of Removal Rate	($1,131,231)		$0
61		Less: Retired Plant		Line 49	($1,500,301)		$0
62		Book Depreciation Reserve 08/31/21		Sum of Line 57 through Line 61	$489,949,834		$38,470,640
63							
64	1/	3 year average retirement over plant addition in service FY 15 ~ FY17		0.0687	Retirements		
65	2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17		0.0518	COR		
66							
67		Book Depreciation RY2		Line 37 (a) + Line 38 (b)			$41,061,654
68		Less: General Plant Depreciation (assuming add=retirement)		Page 10, Line 79(f)			($748,271)
69		Plus: Comm Equipment Depreciation		Page 10, Line 73 + Line 74			$32,079
70		Total					$40,345,462
71		7 Months					x7/12
72		FY 2020 Depreciation Expense					$23,534,853
73							
74		Book Depreciation RY3		Line 58 (a) + Line 59 (b)			$41,670,438
75		Less: General Plant Depreciation		Page 10, Line 79(f)			($748,271)
76		Plus: Comm Equipment Depreciation		Page 10, Line 73 + Line 74			$32,079
77		Total					$40,954,246
78		FY 2021 Depreciation Expense		5 Months of RY 2 and 7 Months of RY 3			$40,700,586

The Narragansett Electric Company
d/b/a National Grid
Forecasted FY 2022 ISR Property Tax Recovery Adjustment
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		End of FY 2018	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr	Retirements	COR	End of FY 2019
1	Plant In Service	$1,195,705	$92,263	$24,845	$117,108		($6,844)		$1,305,969
2	Accumulated Depr	$414,713				$40,858	($6,844)	($6,123)	$442,604
3	Net Plant	$780,992							$863,364
4	Property Tax Expense	$22,678							$23,283
5	Effective Prop tax Rate	2.90%							2.70%
		End of FY 2019	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr	Retirements	COR	End of FY 2020
6	Plant In Service	$1,305,969	$144,120	$22,074	$166,193		($8,567)		$1,463,595
7	Accumulated Depr	$442,604				$41,588	($8,567)	($10,162)	$465,463
8	Net Plant	$863,364							$998,132
9	Property Tax Expense	$23,283							$25,959
10	Effective Prop tax Rate	2.70%							2.60%
		End of FY 2020	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr	Retirements	COR	End of FY 2021
11	Plant In Service	$1,463,595	$148,107	$24,845	$172,951		($20,635)		$1,615,911
12	Accumulated Depr	$465,463				$46,252	($20,635)	($15,619)	$475,461
13	Net Plant	$998,132							$1,140,451
14	Property Tax Expense	$25,959							$30,755
15	Effective Prop tax Rate	2.60%							2.70%
		End of FY 2021	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr	Retirements	COR	End of FY 2022
16	Plant In Service	$1,615,911	$175,462	$22,074	$197,536		($21,933)		$1,791,514
17	Accumulated Depr	$475,461				$50,823	($21,933)	($4,684)	$499,666
18	Net Plant	$1,140,451							$1,291,848
19	Property Tax Expense	$30,755							$33,588
20	Effective Prop tax Rate	2.70%							2.60%

Line			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Cumulative Increm. ISR Prop. Tax for FY2018				Cumulative Increm. ISR Prop. Tax for FY2019 1st 5 month				Cumulative Increm. ISR Prop. Tax for FY2019 7 months		
21	Incremental ISR Additions			$97,810				$92,263				($914)	
22	Book Depreciation: base allowance on ISR eligible plant			($24,356)				($24,356)				$0	
23	Book Depreciation: current year ISR additions			($1,246)				($1,449)				($7)	
24	COR			$8,603				$11,583				$5,627	
25	Net Plant Additions			$80,811				$78,041				$4,705	
26	RY Effective Tax Rate			3.06%				3.06%				2.92%	
	Property Tax Recovery on Growth and non-ISR										7 mos	1.70%	
27	ISR Year Effective Tax Rate		2.90%				2.70%				2.70%		
28	RY Effective Tax Rate		3.06%	-0.15%			3.06%	-0.36%			2.92%	-0.22%	
29	RY Effective Tax Rate 5 mos for FY 2019						5 month	-0.15%				-0.13%	7 mos
30	RY Net Plant times 5 mo rate	7 months	$458,057	-0.15%	($694)		$458,057	-0.15%	($684)		$919,892	* -0.13%	($1,203)
31	FY 2014 Net Adds times ISR Year Effective Tax rate	7 months	$6,343	2.90%	$184		$5,950	1.12%	$67				0
32	FY 2015 Net Adds times ISR Year Effective Tax rate	7 months	$42,913	2.90%	$1,246		$39,920	1.12%	$449				
33	FY 2016 Net Adds times ISR Year Effective Tax rate		$59,527	2.90%	$1,729		$55,693	1.12%	$626				
34	FY 2017 Net Adds times ISR Year Effective Tax rate		$58,883	2.90%	$1,710		$56,076	1.12%	$630				
35	FY 2018 Net Adds times ISR Year Effective Tax rate		$80,810	2.90%	$2,347		$77,664	1.12%	$873		$6,934	1.57%	$109
36	FY 2019 Net Adds times ISR Year Effective Tax rate						$78,041	1.12%	$877		$4,705	1.57%	$74
37	Total ISR Property Tax Recovery				$6,521				$2,837				($1,020)

The Narragansett Electric Company
d/b/a National Grid
Forecasted FY 2022 ISR Property Tax Recovery Adjustment
Forecasted FY 2022 ISR Property Tax Recovery Adjustment (Continued) 1

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Cumulative Increm. ISR Prop. Tax for FY2020				Cumulative Increm. ISR Prop. Tax for FY2021				Cumulative Increm. ISR Prop. Tax for FY2022		
38	Incremental ISR Additions		$105,296				$148,107				$175,462	
39	Book Depreciation: base allowance on ISR eligible plant		$0				$0				($23,890)	
40	Book Depreciation: current year ISR additions		($1,510)				($1,928)				($2,305)	
41	COR		$7,056				$14,506				$4,213	
42	Net Plant Additions		$110,841				$160,685				$153,480	
43												
44	RY Effective Tax Rate		2.96%				3.02%				3.05%	
45	ISR Year Effective Tax Rate	2.60%				2.70%				2.60%		
46	RY Effective Tax Rate	2.96%	-0.36%			3.02%	-0.32%			3.05%	-0.45%	
47	RY Effective Tax Rate 7 mos for FY 2019		-0.36%				-0.32%				-0.45%	
48	RY Net Plant times Rate Difference	$908,586	* -0.36%	($3,246)		$889,353	* -0.32%	($2,886)		$881,383	* -0.45%	($3,957)
49	Growth and non-ISR Incremental times rate difference	($20,407)	* -0.36%	$73		($41,336)	* -0.32%	$134		($51,615)	* -0.45%	$232
50	FY 2018 Net Incremental times rate difference	7,156	* 2.6%	$186		$7,378	* 2.7%	$199		$7,600	* 2.6%	$198
51	FY 2019 Net Incremental times rate difference	4,692	* 2.6%	$122		$4,678	* 2.7%	$126		$4,665	* 2.6%	$121
52	FY 2020 Net Incremental times rate difference	$110,841	* 2.6%	$2,882		$107,821	* 2.7%	$2,908		$104,800	* 2.6%	$2,725
53	FY 2021 Net Adds times rate difference					$160,685	* 2.7%	$4,333		$156,829	* 2.6%	$4,078
54	FY 2022 Net Adds times rate difference									$153,480	* 2.6%	$3,990
55	Total ISR Property Tax Recovery			$17				$4,814				$7,386

Line Notes

1(a) - 10(h)	Docket No. 4916 Attachment MAL-1, Page 17 of 20, 1(a) to 10(h)
11(a) - 15(a)	Per Line 6(h) ~ 10(h)
11(b)	Page 5 of 12 , Line 1 ,Col (d)÷1000
11(c)	Per Company's Book
11(d)	Line 11(b) + Line 11(c)
11(f)	Page 5 of 12 , Line 7 ,Col (d)÷1000
11(h)	Line 11(a) + (d) + (f)
12(e)	Page 9 of 12 , (Line 16 + Line 17 ,Col (a))×5÷12 + Page 9 of 12 , (Line 37 + Line 38 ,Col (a))×7÷12 + (Page 2 of 12 , Line 3, Col (a) + Page 5 of 12 , Line 3, Col (a))÷1000 * 3.05% + Page 8 of 12 , Line 3, Col (a)×0.5×3.05%÷1000
12(f)	=11(f)
12(g)	Page 5 of 12 , Line 4 ,Col (d)÷1000
12(h)	Line 12(a) + (e) + (f) + (g)
13(h)	Line 11(h) - 12(h)
14(h)	Per Company's Book
15(h)	Line 14(h) ÷ 13(h)
16(a) - 20(a)	Per Line 11(h) ~ 15(h)
16(b)	Page 5 of 12 , Line 1 ,Col (e)÷1000
16(c)	Estimated based on FY2020 actual non-ISR addition
16(d)	Line 16(b) + Line 16(c)
16(f)	Page 5 of 12 , Line 7 ,Col (e)÷1000
16(h)	Line 16(a) + (d) + (f)
17(e)	Page 9 of 12 , (Line 58 + Line 59) + (Page 2 of 12 , Line 3, Col (a) + Page 5 of 12 , Line 3, Col (a) + Page 8 of 12 , Line 3, Col (a) + Page 2 of 12 , Line 3, Col (a))÷1000 × 3.05%+ (L1(c)+L6(c)+L11(c))×0.0416 + Page 5 of 12 , Line 3, Col (a)×0.5×3.05%÷1000 + L16(c)×0.5×0.0416
17(f)	=16(f)
17(g)	Page 5 of 12 , Line 4 ,Col (e)÷1000
17(h)	Line 17(a) + (e) + (f) + (g)
18(h)	Line 16(h) - 17(h)
19(h)	Line 18(h) × 20(h)

Line Notes

20(h)	Estimated based on FY2020 actual property rate
21(a) - 37(g)	Docket No. 4916 Attachment MAL-1, Page 17 of 20, 11(a) to 27(g)
21(i) - 55(c)	Docket No. 4916 Attachment MAL-1, Page 18 of 20, 28(a) to
38(f)	Page 2 of 12, Line 4(a)÷1000
38(j)	Page 5 of 12, Line 4(a)÷1000
39(f)	FY21 depreciation is reflected in the NBV at 48(e)
39(j)	- (Page 9 of 12, Line 77(c) ×7÷12)÷1000
40(f)	- Page 2 of 12, Line 12(a)÷1000
40(j)	- Page 5 of 12, Line 12(a)÷1000
41(f)	Page 2 of 12, Line 7(a)÷1000
41(j)	Page 5 of 12, Line 7(a)÷1000
42(f)	Sum of Lines 38(f) through 41(f)
42(j)	Sum of Lines 38(j) through 41(j)
44(f)	=Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1, Sch 1-G, P2, L15, Col (c) ÷
44(j)	=Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1, Sch 1-G, P2, L15, Col (c) ÷
45(e)	=15(h)
45(i)	=20(h)
46(e)	=44(f)
46(f)	45(e) -46(e)
46(i)	=44(j)
46(j)	45(i)-46(i)
47(f)	=46(f)
47(j)	=46(j)
48(e)	=Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att.1, Sch 6-G: (P2, L30 - L41 + P3, L5(d) - P5, L4(d) - Sch 5-G, P1, L1(e) + L1(g)) × 5÷12000+(P2, L51 - L62 + P3, L5(d) - P5, L4(d) - Sch 5-G, P1, L1(e) × 3) × 7÷12000

Line Notes

48(g)	48(e) ×47(f)
48(i)	=Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1: (Sch 6-G, P2, L51 - L62 + P3, L5(d) - P5, L4(d) - Sch 5-G, P1, L1(e) × 3 ÷1000
48(j)	=47(j)
48(k)	48(i)×47(j)
49(e)	= - Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1: Sch 11-G, P5, L3(h)+L3(i)+L7(h)+L7(i)
49(g)	49(e) ×47(f)
49(i)	= - Rate Case, Docket 4770, Compliance, Revised Rebuttal. Att. 1: Sch 11-G, P5,
49(j)	=47(j)
49(k)	49(i)×47(j)
50(e)	Line 50(a) - Page 2 of 12, Line 12(d))÷1000
50(g)	=50(e) ×45(e)
50(i)	Line 50(e) - Page 2 of 12, Line 12(e))÷1000
51(e)	Line 51(a) - Page 5 of 12, Line 12(c))÷1000
51(g)	=51(e) ×45(e)
51(i)	Line 51(e) - Page 5 of 12, Line 12(d))÷1000
52(e)	Line 52(a) - Page 8 of 12, Line 12(b))÷1000
52(g)	=52(e) ×45(e)
52(i)	Line 52(e) - Page 8 of 12, Line 12(c))÷1000
53(e)	=42(f)
53(g)	=53(e) ×45(e)
53(i)	Line 53(e) - Page 2 of 12, Line 12(b))÷1000
54(i)	=42(j)
54(k)	=54(i)×45(i)
55(g)	sum of 48(g) through 53(g)
55(k)	sum of 48(k) through 54(k)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Investment Forecast Update
Calculation of Weighted Average Cost of Capital

Line No.						
1	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 35% income tax rate effective April 1, 2013					
2		(a)	(b)	(c)	(d)	(e)
3		Ratio	Rate	Weighted Rate	Taxes	Return
4	Long Term Debt	49.95%	5.70%	2.85%		2.85%
5	Short Term Debt	0.76%	0.80%	0.01%		0.01%
6	Preferred Stock	0.15%	4.50%	0.01%		0.01%
7	Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
8		100.00%		7.54%	2.51%	10.05%
9						
10	(d) - Column (c) x 35% divided by (1 - 35%)					
11						
12						
13	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 21% income tax rate effective January 1, 2018					
14		(a)	(b)	(c)	(d)	(e)
15		Ratio	Rate	Weighted Rate	Taxes	Return
16	Long Term Debt	49.95%	5.70%	2.85%		2.85%
17	Short Term Debt	0.76%	0.80%	0.01%		0.01%
18	Preferred Stock	0.15%	4.50%	0.01%		0.01%
19	Common Equity	49.14%	9.50%	4.67%	1.24%	5.91%
20		100.00%		7.54%	1.24%	8.78%
21	(d) - Column (c) x 21% divided by (1 - 21%)					
22						
23	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4770 effective September 1, 2018					
24		(a)	(b)	(c)	(d)	(e)
25		Ratio	Rate	Weighted Rate	Taxes	Return
26	Long Term Debt	48.35%	4.98%	2.41%		2.41%
27	Short Term Debt	0.60%	1.76%	0.01%		0.01%
28	Preferred Stock	0.10%	4.50%	0.00%		0.00%
29	Common Equity	50.95%	9.28%	4.73%	1.26%	5.99%
30		100.00%		7.15%	1.26%	8.41%
31	(d) - Column (c) x 21% divided by (1 - 21%)					
32						
33	FY18 Blended Rate		Line 8(e) × 75% + Line 20(e) × 25%			9.73%
34						
35	FY19 Blended Rate		Line 20 x 5 ÷ 12 + Line 30 x 7 ÷ 12			8.56%

PUC 6-9

Request:

Referring to Attachment PUC 3-4 (page 3 of 3) and the response to PUC 3-34 (page 1), there is a reference to the Company "onboarding" an "Owners Engineer" for the Cumberland tank replacement project. Please clarify whether it would be an outside consultant or an employee of a National Grid company and provide greater detail on how the estimate for the Owners Engineer cost was developed.

Response:

An "Owners Engineer" would be an outside consultant working on behalf of the Company. The Owner's Engineer will help take a project from concept through commissioning. The Company has not yet received bids for the Owners Engineer. That, together with the fact that the Cumberland tank replacement project is unique, large-in-scale and complex, means that the estimates provided are high-level and based on engineering judgment. The Company will receive better clarity on estimates once it receives he bids for the Owners Engineer.

PUC 6-10

Request:

Referring to the response to PUC 3-17, assuming a filing date at the EFSB in CY 2023, what is the best estimate of the fiscal year in which the contemplated capital project would be placed into service if the EFSB approves it?

Response:

Assuming a filing date at the EFSB in CY 2023, the Company estimates that the Cumberland LNG tank will be placed into service in fiscal year 2027.

Prepared by or under the supervision of: Joshua Bleicken

PUC 6-11

Request:

Referring to the response to the testimony of Smith & Kocon at page 17 of 30, please state the approximate date the Company anticipates it will be filing an application with the EFSB for its "hybrid" solution and, assuming approval by the EFSB for the Company's preferred option, please provide an estimate of the fiscal year when construction of the infrastructure would commence and the fiscal year when the infrastructure would be placed in service.

Response:

As indicated in the Company's response to PUC 1-6, the Company currently anticipates that it will file an application with the EFSB for its hybrid solution in Q4 of fiscal year ("FY") 2022.

The Company estimates that the EFSB process will take approximately 18 months. Assuming EFSB approval of the Company's preferred option in Q1 of FY 2024, the Company estimates that construction of the infrastructure would commence in FY 2026. The Company anticipates that the main installed in FY 2026 will be placed into service in FY 2026, with the remaining main installation and new portable LNG site in service in FY 2027.

Prepared by or under the supervision of: Amy Smith and Faye Brown

PUC 6-12

Request:

PUC 3-14 states that the purchase of capital tools will be $501,000 for FY 21, while the line item for "Tools & equipment" in Attachment PUC 3-3-1 forecasts spending at the budget level of $603,000. Please reconcile these two answers.

Response:

The FY 2021 forecast for "Tools & Equipment" as of December 31, 2020, was correctly listed as $603,000 in Attachment PUC 3-3-1. The $603,000 forecast is comprised of $501,000 for Capital Equipment/Tools and $102,000 for Meter Testing Equipment.

Below is a table that reconciles/explains the differences between PUC 3-14 (column A) and Attachment PUC 3-3-1 (column C). The variance between the two totals is made up of the remaining non-itemized forecasted spending for FY 2021, which is listed in column B.

	A	B	A+B = C
Category	**Response 3-14 (Actual + Itemizable Forecast)**	**Remaining Non-Itemized Forecast**	**PUC 3-3-1 Total Forecast**
Capital Equipment/ Tools	$488,788	$12,212	$501,000
Meter Testing Equipment	$11,000	$91,000	$102,000
Total	$499,788	$103,212	$603,000

Prepared by or under the supervision of: Nathan Kocon

PUC 6-13

Request:

Does the Company have tools which it classifies as "capital tools" for the electric distribution business? If so, does the Company recover the revenue requirement for such capital tools through the Electric ISR? If so, please indicate the amount of capital tools which the Company has budgeted in the Electric ISR in each year of the Electric ISR.

Response:

Yes, the Company has tools that it classifies as "capital tools" for the electric distribution business. The Company recovers the costs of its capitalized tools through the Electric ISR revenue requirement. Costs are included in the "General Equipment" line item of the Non-infrastructure spending category in the General Equipment Blanket project COS0006. As noted in the Company's response to Data Request PUC 1-12 in Docket 5098, the Company has budgeted $250,000 for capitalized tools for FY 2022. The table below shows the budgets for FY 2012 – FY 2022.

Fiscal Year	**Budgeted Spending $'000s**
FY 2012	$278
FY 2013	$186
FY 2014	$105
FY 2015	$102
FY 2016	$100
FY 2017	$100
FY 2018	$378
FY 2019	$306
FY 2020	$300
FY 2021	$330
FY 2022	$250

Prepared by or under the supervision of: Patricia Easterly

PUC 6-14

Request:

PUC 3-16 appears to indicate that the Company will spend only $95,149 on Access Protection Remediation in FY 21, while the same line item in Attachment PUC 3-3-1 indicates that the Company will spend the full budgeted amount of $260,000. Please reconcile these two answers.

Response:

The Company's FY 2021 forecast for the Access Protection Remediation Program as of December 31, 2020, was $260,000 as shown in the Company's response to Data Request PUC 3-3-1. In its response to Data Request PUC 3-16, the Company provided a list of work completed to date in the Access Protection Remediation program with associated spending of $95,149. This response did not include a forecast to year-end spending.

The Company has now updated its forecast of year-end spending for this program, and the forecasted amount is $110,000. The reduction in forecast spending is due to COVID-19 Pandemic-related travel restrictions for the engineers scheduled to perform necessary field verifications. Thus, the Company was unable to complete all planned field verifications in early FY 2021 needed for project designs and completion during the year. The Company plans to use the remaining FY 2021 budget for limited field verifications, site visits and design for FY 2022 work.

Prepared by or under the supervision of: Saadat Khan

PUC 6-15

Request:

Referring to the response to (i) PUC 3-21 which indicates that the Company has not replaced more than 14,383 meters over the last four fiscal years and (ii) PUC 3-22 which states that the Company forecasts that it will install 18,640 meters in FY 2022, please explain the basis of the Company's belief that it will be able to install nearly 30% more meters in FY 2022 than it has been able to install in recent years back to FY 2017.

Response:

To align with the Company's service quality requirements, the Company's meter change plan is based on a calendar year rather than a fiscal year. The Company currently employs 10 additional Customer Meter Service technicians as compared to Calendar Year 2020. Additionally, new Gas Business Enablement tools have streamlined the Customer Contact, Scheduling and Dispatch systems. These two factors allowed the Company to change 2,749 meters in January, which is nearly 1,000 more meters changed than in any other month in the last two calendar years. As such, the Company believes that the 18,640 meter change plan is achievable.

Prepared by or under the supervision of: Saadat Khan

PUC 6-16

Request:

Referring to the response to PUC 3-25, (a) please provide citations, regulatory language, and copies of the referenced "regulatory requirements", (b) please explain in greater detail and show how the Company determined that it must install 18,640 meters in FY 2022 to be in compliance with those regulatory requirements, and (c) please explain why the Company determined that it must purchase 18,600 meters for FY 2022 to meet the requirements, given the projection of 12,245 meters that will be left in inventory as of FY 2022 year-end (as indicated in PUC 3-22).

Response:

a) The Company's meter change program is designed to comply with both the Rhode Island Division of Public Utilities and Carriers (Division) regulations and with terms established by the Division in a Notice of Probable Violation issued in 2006. Specifically, the Division code establishes requirements to change gas meters on either a 10-year or a 15-year cycle based on meter type and size. In addition, a 2006 NOPV issued by the Division confirmed that National Grid would be found to satisfy its meter change requirements at each location by either completing the meter change or by exhausting all attempts via phone calls and letters to contact a customer to schedule a meter change appointment. The Company reports on both changes and attempted appointments in its Quarterly Service Quality report filed with the Division. Please see 815-RICR-20-00-1, Rules and Regulations Prescribing Standards for Gas Utilities, Master Meter Systems and Jurisdictional Propane Systems. See also Attachment PUC 6-16 for a copy of NOPV 06-1.

b) The Company uses several factors to establish its annual meter change work plan. First, the Company evaluates the number of meters due for change over a multi-year period in accordance with the Division regulations for the 10-year and 15-year compliance cycles for Commercial/Industrial and Residential meter changes. The Company then determines average change rates required to meet compliance obligations and allocates resources in a sustainable way to meet a multi-year goal. The Company also analyzes the trend in customer response rates to contact attempts to set appointments relative to the population of meters due for change and ensures that the resource allocation matches the response rate.

c) The Company is proposing to purchase 9,600 meters in FY 2022. This equates to a FY 2022 projected year-end inventory of 7,398 meters. Please see the Company's amended response to response to PUC 3-22, which the Company filed on February 23, 2021.

Prepared by or under the supervision of: Saadat Khan

RECEIVED
2006 JUN 22 PM 3: 19
PUBLIC UTILITIES COMMISSION

New England Gas Company

June 22, 2006

Don A. Ledversis
Gas Pipeline Safety Engineer
Rhode Island Division of Public Utilities and Carriers
89 Jefferson Blvd.
Warwick, Rhode Island 02888

RE: Notice of Probable Violation 06-1

Dear Mr. Ledversis:

New England Gas Company ("Company") is in receipt of the May 26, 2006 letter from the Rhode Island Division of Public Utilities and Carriers ("Division") entitled "Division Response to March 2, 2006 Informal Hearing on NOPV 06-1." The Division's letter addresses the dialogue that has occurred between the Division and the Company since February 27, 2006 relative to the Division's NOPV 06-1, which alleges a failure by the Company to change 215 commercial gas meters in the former Valley Gas territory. The Company greatly appreciates the opportunity offered by the Division to further address the allegations and to present an action plan for periodic meter testing that would govern meters due for testing pursuant to the Division's Rules and Regulations Prescribing Standards for Gas Utilities, Effective July 1, 1966 ("1966 Regulations").

As an initial matter, the Company would like to address the Division's perception (as set forth in the letter at page 1) that the Company claims that the 1966 Regulations regarding meter testing do not apply to the Company because they are superseded or "pre-empted" by the SQ Plan established by the Rhode Island Public Utilities Commission (the "Commission") in Docket No. 3476. This is not the case. On the contrary, the Company is in complete agreement with the Division that the 1966 Regulations apply to the Company's meter-testing operations and dictate the periodicity of meter tests within the Company's service territory.[1] The SQ Plan does not establish the period for testing, but rather sets a target threshold for the minimum number of tests that will be performed each year. Therefore, the point at issue for the Company is not whether the SQ Plan supersedes the 1966 Regulations (it does not). The Company's only point is that the 15,000 meter-test threshold set in the SQ Plan was developed by the Company and the Division with the recognition that, in most years, the target threshold in the SQ Plan will exceed the number of meter tests that would be actually due on the periodic cycles set by the 1966 Regulations. Because the number of tests required by the SQ Plan would exceed the number of tests due in a given year under the 1966 Regulations, the Company's compliance with the SQ

[1] In the letter of May 26, the Division notes that the Company did not raise any issue regarding the relevance of the SQ Plan meter-testing provisions in comments to the Division on the proposed revised "Rules and Regulations Prescribing Standards for Gas Utilities" (the "Revised Rules"). This is true. The Company did not raise the issue of the SQ Plan meter-testing requirements in its written comments or meetings with the Division regarding the Revised Rules because the Company is in full agreement that it is subject to those portions of the 1966 Regulations relevant to meter testing.

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Providence, RI 02903

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Plan (and the threshold established therein) would have the effect of reducing the backlog of meter tests that existed at the time that the SQ Plan was established. Therefore, it was the Company's understanding that the establishment of the 15,000-meter test threshold (in agreement with the Division) was specifically designed to provide the Company with the opportunity to work down the existing backlog of meter tests over the next several years without incurring a penalty under the 1966 Regulations. This backlog includes the 215 meters that are the subject of NOPV 06-1.

Therefore, the Company's claim is not that the 1966 Regulations are "pre-empted" by the SQ Plan (they are not). Rather, the Company understood that the establishment of the SQ Plan represented an agreement by the Division that the *penalty* that could be assessed to the existing backlog under the 1966 Regulations, would not be assessed, so as long as the Company met the target level of 15,000 meter tests per year under the SQ Plan. In consideration of this agreement, the Company agreed to pay a penalty under the SQ Plan if it did not meet the target level of 15,000 meter tests per year. This is an important point because there are some years where the 15,000 meter-test threshold exceeds the number of meters due to be tested under the periodic cycles set in the 1966 Regulations. For example, in 2006, approximately 8,073 meters are due to be tested under the 1966 Regulations (7,338 residential meters and 735 commercial meters). By the end of the year, the Company will have tested 15,000 meters *at a minimum* in order to comply with the SQ Plan, and more likely will have tested several thousand more meters than the 15,000 meter threshold. As a result, the existing backlog of meter tests will be reduced substantially in just the next year.

In fact, as noted in the Company's May 5, 2006 letter to the Division, the number of meter tests performed by the Company over the past several years has far exceeded the 15,000 meter-test threshold established under the SQ Plan. Consequently, the Company has already made substantial progress in reducing the existing backlog as designed by the Division and the Company in agreeing on the SQ Plan. At the Company's accelerated rate of meter testing, it is on track to eliminate the existing backlog of commercial meters in approximately five years and to eliminate its existing backlog of residential meters in three years.[2] Given the difficulties that the Company encounters in accessing customer premises to perform the meter tests, this is substantial progress by any account.

The lack of customer acquiescence to meter testing, particularly by some commercial customers, presents a persistent and irresolvable obstacle to the Company in coming in compliance with the 1966 Regulations. Therefore, any program targeted at completing meter tests under the 1966 Regulations on a timely basis <u>must</u> include a provision to deal with meter-access issues. For this reason, the Company's proposal below incorporates a mechanism for dealing with these issues.

[2] The Company's existing backlog of "large" (above 400 cubic feet per hour) meter tests is 2,198. The Company's existing backlog of small (400 cubic feet per hour or smaller) untested meters is 24,714. In 2005, the Company tested over 18,300 meters.

Accordingly, in terms of a going-forward action plan consistent with the plan design and considerations discussed above, the Company proposes the following:

(1) The Company will work down the existing backlog of untested commercial meters by testing a minimum of 1,150 commercial meters per year for the next five years, on a best efforts basis;

(2) The Company will work down the existing backlog of untested residential meters by testing a minimum of 16,000 residential meters per year for the next three years, on a best efforts basis;

(3) The Company will target its oldest vintage untested meters for testing, subject to item (4), below; and

(4) At the end of each calendar-year quarter, the Company will generate a list of customer premises to which access to the meter for testing purposes has been denied by the customer. The Company will maintain documentation of the efforts made to contact the customer and gain access.

Specifically, the Company will adhere to and document the following process to attempt to gain access:

- The Company will first attempt to contact the customer to schedule an appointment for a meter test/exchange by telephone. The Company will make three attempts (once in the morning, once in the evening and once on a weekend) to contact the customer, each time leaving a message for the customer to call the Company.
- If calls fail to elicit a response, the Company will send a letter to the customer requesting access to the customer's meter(s) for testing/exchange and asking the customer to call the Company to arrange for an appointment.
- If, after two letters are sent to the customer, the customer does not respond or provide the Company with access to the meter(s) at issue, the Company will list the customer on the quarterly report to the Division for its assistance in gaining access.

If the Company has completed the formal notification procedure outlined above and has included the customer premises on the Quarterly Report to the Division, the Division would suspend any enforcement action under the 1966 Regulations against the Company in relation to an identified customer meter, unless and until such time that the Division is able to assist the Company in gaining access to the meter(s) at issue. Once access is provided, the Company will test the meter and the meter location would be returned to the meter-testing "pool" for future testing in accordance with the 1966 Regulations.[3]

Based on the Company's experience and commitment to reduce the backlog of meter tests in existence prior to January 1, 2006, the Company believes that the program outlined above represents a serious and well-designed effort to: (1) reduce the current backlog for commercial meters within five years and for residential meters within three years; (2) complete the most overdue meter tests on a priority basis; and (3) create a fair and reasonable process to ensure that the Company is not penalized in the future for meter tests that are overdue through no fault of the Company. Therefore, from an overall perspective, the Company's proposal will meet the objectives of the Division.

On behalf of the Company, I would like to convey my sincere appreciation for the Division's interest in this matter and the opportunity extended by the Division to establish a targeted program to address its meter-testing concerns rather than simply assessing a penalty. If you have any questions with respect to any of these comments, please feel free to contact me directly at (401) 574-2253.

Sincerely,

Michael E. Sullivan
Vice President of Operations

cc: Thomas F. Ahern, Administrator
James Lanni, Associate Administrator

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3 Although not directly related to the issues presented in the NOPV, the Company recently advocated that Section 16 of the Division's proposed revised "Rules and Regulations Prescribing Standards for Gas Utilities" ("Revised Rules") be further revised to allow meters to be tested using a random sampling program agreed to by the Division and the local distribution company (see New England Gas Company Letter to Division re: Revised Rules, dated October 28, 2005). The Company proposed this revision in an effort to: (1) reduce the number of unnecessary tests; (2) allow data collected to address problem meters; (3) improve the overall performance of the meter population by removing poor performing meters and leaving superior performing meters in service; and (4) mitigate unnecessary interruptions to customers with superior meters (id.). In response to the Company's proposal, the Division extended an invitation to the Company to present a plan that supports random sampling (Division Letter to Company Re: Revised Rules, dated January 6, 2006, at 5). The Company may pursue the development of a random sampling program once the Company's currently proposed merger with National Grid is completed.

PUC 6-17

Request:

Referring to the responses to PUC 3-21 and 3-25, for each fiscal year beginning in FY 2017 through FY 2021, (a) please indicate whether the Company met its meter change-out regulatory requirements, (b) the number of meters the Company needed to change out in order to be in compliance with those "regulatory requirements" for each of those years, (c) the number by which the Company fell short or exceeded the requirements, and (d) the number of meters that were purchased for each respective year.

Response:

a) The Company did not meet its meter change-out requirement in calendar years ("CY") 2017 through 2020.The Service Quality Regulatory Meter Testing metric is based on calendar year (ending 12/31) and not the fiscal year (ending 3/31). Therefore, the Company cannot yet report whether it met its meter change-out requirement for calendar year 2021.

b) & c) Since Meter Testing is a calendar year program, the Company's regulatory requirement is based on calendar year. From CY 2017 To CY 2020, the required Total Meter Test Requirement and Total Meters Credited are shown in the table below. Please see the Company's response to PUC 6-16, which describes the compliance requirement in accordance with Division regulations as including meters changes and attempts to schedule meter change appointments. Please note that CY2020 meter changes were impacted by the Covid-19 Pandemic. For the majority of the year, the Company did not attempt to make appointments because the program was suspended due to the Company's concern regarding customers' and employees' exposure to the virus.

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PUC 6-17, page 2

Year	Total Meter Test Requirement	Actual Changed	Compliant Attempts	Inactive meters	Total Meters Credited (changed + attempts + inactive)	Exceed/ (Short)
CY20	36,508	3,926	21,525	3,241	28,692	(7,816)
CY19	36,546	13,496	20,766	1,762	36,024	(522)
CY18	34,792	13,694	17,791	1,363	32,848	(1,944)
CY17	31,250	14,302	14,969	1,260	30,531	(719)

d) The table below outlines the meters purchased by fiscal year.

FY17	FY18	FY19	FY20
11,923	17,174	18,076	23,528

PUC 6-18

Request:

Please review the following information taken from the referenced responses and reconcile the inventory estimate of 12,245 in PUC 3-22 with the ending inventory calculation of 11,690 shown below, or show why the calculation of 11,690 meters is incorrect:

Balance EOY FY 2020	9,880	PUC 3-21(b)
FY 2021 Purchases	8,820	PUC 3-19
Total	18,700	
Install by 3/31/21	(6,970)	PUC 3-20
Inventory at 3/31/21	11,730	
FY 2022 Purchases	18,600	PUC 3-26
Total	30,330	
FY 2022 Install	(18,640)	PUC 3-22
Ending FY 2022 Inventory	11,690	
Ending FY 2022 Inventory	(12,245)	PUC 3-22
Variance	(555)	

Response:

The Company has filed amended responses to both PUC 3-21 and PUC 3-22 to correct errors follows:

PUC 3-21

The Company changed the end of year ("EOY") FY 2020 inventory from 9,880 to 5,588. This change in inventory forecast is based on the actual count of meters in inventory as of February 18, 2021 and comparing against meter changes and number of meters ordered in

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FY 2021 to date. The previously submitted inventory level was estimated using the Company's information technology("IT") systems, which are not designed to capture and store historic point-in-time inventory level management.

PUC 3-22

The Company changed the forecasted EOY FY 2022 inventory from 12,245 to 7,398. Similar to PUC 3-21, this change in inventory forecast is based on actual count of meters in inventory as of February 18, 2021, and comparing against meter changes and number of meters ordered this FY 2021 to date. The previously submitted inventory level was estimated using the Company's IT systems, which are not designed to capture and store historic point-in-time inventory level management.

Specifically, the Company manually counted every meter in current inventory as of February18, 2021 and added to that number orders yet to be received this fiscal year, for a total of 17,638 meters. In addition, the Company's technicians have changed more meters than planned in Q4 FY 2021, completing approximately 2,500-meter changes quarter to date against 3,700 planned for the entire quarter which ends 3/31/2021. The Company then compared the estimated year-end inventory of 17,638 meters and subtracted the 1,200 remaining meters for Q4 meter changes for FY 2021. This results in an updated estimated inventory of 16,438 for the end of FY 2021. The Company believes that this number represents the most accurate forecast of meters in inventory at the end of FY 2021. Any reduction in the proposed budget will reduce the Company's ability to meet meter change and testing regulatory requirements. Additionally, as noted in the Company's response to PUC 3-15, the Company is outperforming forecasted meter changes in the fourth quarter of FY 2021 and anticipates that this trend will continue, which will help reduce the current backlog of meters change work. The Company needs to ensure that adequate inventory is available to support scheduled meter change appointments. The table below compares the table provided by the PUC in PUC 6-18 to the updated numbers in the Company's amended responses to PUC 3-21 and PUC 3-22. Using the numbers from the amended responses, the variance in the actual and expected inventory levels is zero.

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PUC 6-18, page 3

	PUC 6-18	NG Response	NG Comments
Balance EOY FY 2020	9,880	5,588	Amended 3-21
FY 2021 Purchases	8,820	17,820	PUC 3-19 (a)
Total	18,700	23,408	
Install by 3/31/21	(6,970)	(6,970)	
Inventory at 3/31/21	11,730	16,438	
FY 2022 Purchases	18,600	9,600	PUC 3-26
Total	30,330	26,038	
FY 2022 Install	(18,640)	(18,640)	
Ending FY 2022 Inventory	11,690	7,398	
			Amended 3-22
Ending FY 2022 Inventory	(12,245)	(7,398)	
Variance	(555)	0	

Prepared by or under the supervision of: Saadat Khan

PUC 6-19

Request:

Refer to PUC 3-22 which states that the total dollar value of the 18,640 meters is "fully loaded, which includes meter cost, gas communication modules, meter lab labor, capital overheads, labor burdens, meter refurbishments, sales tax and deliveries. (a) What is the average cost per meter of the meters alone (not fully loaded)? (b) Please state the total cost of the meters, as purchased directly from the vendors (excluding fully loaded costs). (c) Please explain whether it is common across all U.S. state jurisdictions for National Grid to charge the fully loaded capital cost of meters in rates (including inventory) prior to the meters actually being installed in the relevant rate year? (d) Please explain why it is reasonable to charge ratepayers for the revenue requirement associated with a fully loaded meter value which includes installation costs before the Company has actually placed the meters into service.

Response:

(a) Below is the average contractual cost of meter by class:

Class	Average Price
250	$ 67.89
425	$ 136.85
630	$ 436.11
800	$ 503.90
1000	$ 528.41
15C175 ES3 Meter	$ 1,200.50
3M175 ES3 Meter	$ 1,226.50
5M175 ES3 Meter	$ 1,385.00
7M175 ES3 Meter	$ 1,661.00
11M175 ES3 Meter	$ 1,775.00
16M175 ES3 Meter	$ 2,323.00
16M175 Series B3 Dresser	$ 2,046.50
16MTD Series B3 Meter	$ 2,323.00
23M232 (CD) series Meter	$ 3,379.00

Prepared by or under the supervision of: Saadat Khan

PUC 6-19, page 2

(b) The Company cannot forecast total meter costs for FY 2022 because it has not yet determined the specific meter purchase forecast by meter type, which will impact the total cost as meter pricing varies by size and model.

(c) The fully loaded meter costs include all the costs associated with bringing a meter to ready for installation stage, but do not include meter installation costs. When a new Gas meter is purchased, it must pass the meter shop test. Therefore, the test associated costs such as gas communication modules, meter lab labor, capital overheads, labor burden are part of meter costs. Consistent with FERC regulations, Gas meter costs are recorded as plant in service when purchased, whether it is actually in service or held in reserve. This Gas meter cost treatment is the same across all U.S. state jurisdictions for National Grid.

(d) As stated in subpart (c) above, the fully loaded meter costs included in the Gas ISR Plan do not include meter installation costs. The Company does not charge customers a revenue requirement associated with meter installation costs through the Gas ISR. For meters purchased under the Gas ISR meter replacement programs, any installation costs associated with such work are recorded to operating & maintenance expense, as that work is associated with the replacement of meters on existing services, not the initial installation of meters for new services.

Prepared by or under the supervision of Saadat Khan

PUC 6-20

Request:

Referring to PUC 3-27, please provide a copy of the negotiated bulk pricing agreement(s) that based pricing on total demand for all its U.S. operating companies for FY 2020 and FY 2021, and indicate the total meters purchased by each of the applicable National Grid operating companies for FY 2020 and FY 2021 and the prices obtained.

Response:

Please see Attachments PUC 6-20-1 through PUC 6-20-6 for the bulk pricing agreements.

The contractual agreements leverage the total number of meters being purchased across all the Company's jurisdictions. As a result, the price the Company pays for a meter is the same in all regions.

The Company notes that while the pricing is negotiated on a bulk basis for all National Grid operating companies, meters are purchased using Company-specific purchase orders. Furthermore, meters are labeled with operating company-specific information before they are shipped by the vendor, ensuring that only meters purchased for a specific operating company are included in the inventory of that operating company. Please see table below for the number of meters purchased by each operating company in FY 2020 and FY 2021 year to date.

The prices obtained are shown in Attachments PUC 6-20-1 through PUC 6-20-6 to this response. Year-to-date, FY 21 total purchases are 52 percent higher than FY 20 as the result of advanced purchases made in anticipation of future price increases.

PUC 6-20, page 2

Gas Meter Purchases by Operating Company		
	FY 2020	**FY2021**
Narragansett Electric	14,528	14,089
Boston Gas Company (includes former Colonial Gas)	69,611	94,556
KeySpan Energy Delivery NY	10,190	28,436
KeySpan Energy Delivery LI	10,533	18,904
Niagara Mohawk	10,208	19,228
Total	115,070	175,213

REDACTED

Reference: 2020 Pricing
Quote #: OPTY - 2018 - 012149 R1

DATE: 4-Nov-19

TO:
National Grid
300 Erie Blvd, West
Syracuse, NY 13202
Kirsti DeMarco

Elster American Meter Company, LLC
A Honeywell International Inc. Company
2221 Industrial Rd
Nebraska City, NE 68410
(402) 873-8200

Payment Terms: NET CASH, 30 DAYS
Freight Terms: Origin, Freight Prepaid
Term & Conditions: Attached
Pricing Validity: Pricing valid for product shipped on or before: 3/31/2021

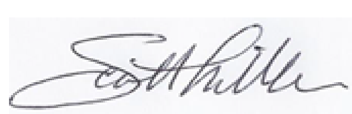
SHIPPING POINTS:
Meters: Nebraska City, NE
Industrial Regulators: Nebraska City, NE
Residential Regulators: Laredo, TX
Refurbished Meters: Cartersville, GA

SUPPLEMENTAL COMMENTS	
1	Elster American Meter Company, LLC, A Honeywell International Inc. Company, submits this bid contingent upon the parties' mutual agreement to the terms of an extension of Agreement –SAP Contract: 4400006491
2	Prices quoted will remain firm for product shipped through March 31, 2021. Subsequent annual price adjustments will be based on changes to the Producer Price Inces (PPI) for Integrating and Totalizing Meter for Gas and Liquids (PCU 3345143345145) as published by the U.S. Department of Labor, Bureau of Labor Statistics (http://data.bls.gov/bin/srgate).
3	Both Parties shall have the right to introduce price adjustment requests associated with actual increases or decreases in costs associated with specification changes, production costs, increases or decreases in costs associated with new or changing governmental regulations, new tariffs and other cost-based change required that are reasonable under the circumstances and mutually agreeable. If the Parties are unable to agree on requested price adjustments, either Party may give the other Party sixty (60) days advance written notice of its intent to terminate the Agreement.
4	Tariff surcharge included in product pricing.

CONFIDENTIAL & PROPRIETARY

Quote #: OPTY - 2018 - 012149 R1

ITEM	QTY.	DESCRIPTION	PRICE	
			Each	Extended
1	30,000	AC250NX 5# TC w/AMR Installed	[redacted]	
2	30,000	AC250 5# TC w/AMR Installed		
3	10,800	AT210 5# TC w/AMR Installed		
4	1	AT210 5# TC w/AMR Installed		
5	2,000	AT250 5# TC w/AMR Installed		
6	5,000	AL425 10# TC w/AMR Installed		
7	6,000	AC630 25# TC w/AMR Installed		
8	1	AC800 25# TC w/AMR Installed		
9	2,500	AL800 20# TC w/AMR Installed		
10	150	AL800 100# TC w/AMR Installed		
11	2,500	AL1000 25# TC w/AMR Installed		
12	25,000	1813B2, 3/4" or 1" NPT, 180 Degree		
13	5,000	1813B2, 1-1/4" NPT, 180 Degree		
14	250	1813B, 1.5" or 2" NPT		
15	150	1813B, 2" Flanged		
16	200	1843B2, 3/4" or 1" NPT, 180 Degree		
17	200	1843, 2" Flanged		
18	150	1843, 1.5" or 2" NPT		
19	200	3000 Regulator, 1.25", 1.5" or 2" NPT		
20	30	3000 Regulator, 2" Flanged		
21	15	3000 Regulator, 3" Flanged		
22	10	3000 Regulator, 4" Flanged		
23	20	2" slam Shut		
24	10	3" Slam Shut		
25	10	4" slam Shut		



BY: ____________________

Scott K. Miller
Honeywell Sales Representative

REDACTED

Itron

Electric / Gas / Water
Information collection, analysis and application

2111 N. Molter Rd.
Liberty Lake, WA 99019
fax: 866-787-6910
www.itron.com

Pricing Summary for
National Grid

BMR# 9923-16 Ver3 Sep
September 23, 2016

Item	Part Number	Description	Qty	Unit Price	Extended Price	Notes
Endpoints						
1	ERG-9000-101/102	100G Datalogging Residential Gas Module	1,500,000	[redacted]		
2	ERG-9000-103	100G Datalogging Commercial/Remote Gas Module	2,500			
		Total				

Notes and Assumptions

(1) Residential 100G Gas Modules are packaged and sold in quantities of 10. Commercial Gas Modules are sold in quantities of 5. Remote Gas Modules are sold in quantities of 20.

(2) A surcharge of $25.00 will apply for ordering modules in less than box quantities.

(3) The prices above are contingent upon National Grid's commitment to purchase 35,000 I-250, 10,000 400A, and 500 800A/1000A gas meters per year, for the next 3 years.

(4) Shipment terms will be FOB origin freight collect. Customer will select its own carrier, negotiate rates, shipping terms, and remit payment directly to the carrier. Customer accepts it sole obligation to purchase freight insurance if desired and understands that Itron will not purchase freight insurance on Customer's behalf. Customer further understands that it is Customer's responsibility to report any damages and submit any claims directly to its carrier or insurer. Customer assumes all liability associated with shipments during this term, and Itron will not be liable for any claims due to delays in shipment or damages to goods, provided that the goods were delivered to the shipping point as scheduled and packaged appropriately. Once the pickup date is confirmed with Itron and the Customer's carrier, if the carrier has not picked up the order within three (3) business days after the confirmed pickup date, then Itron reserves the right to arrange shipping, ship the product to Customer, and bill Customer for the actual freight cost

(5) Delivery Lead Time:

1. The definition of lead time is as follows:
   a. The time elapsed between Customer's placement of an order and Seller's delivery of the ordered product to Customer's specified delivery location.
      - A product is deemed ordered by Customer when Customer issues a purchase order to Seller. Customer's purchase orders will contain the following information:
        - Date
        - Contract date
        - Customer name
        - Purchase order number
        - Reference to pricing
        - Reference to product ordered
        - Quantity of product ordered
        - Delivery locations for the product
        - Required Date
      - Within three (3) to five (5) business days of receipt, Contractor will acknowledge all Purchase Orders placed by Company. Following acknowledgment, Contractor shall make its best commercial efforts to accept or reject within three (3) business days the Purchase Order as placed by Company.
        - If no issue with the Customer's purchase order is identified during the Purchase Order Review Window, the lead time will commence as of the date the Purchase Order is received by Seller.
        - If an issue with the Customer's purchase order is identified during the Purchase Order Review Window, Seller shall immediately notify Customer and the lead time will not commence until Customer has provided Seller with the missing information. The lead time will commence upon Customer's provision of the information.

   b. Deliveries defined as meeting lead time are those that are received on the Company "required date" and up to seven days preceding the required date.

   c. Deliveries defined as not meeting lead times are those that are received after the required date or eight or more days preceding the required date, unless communicated delay prior to required date.
2. Lead time as of agreement execution are as follows:
   a. Electric meters: 10-12 weeks (50-60 business days) ARO for forecasted meters
   b. Gas meters: 8-16 weeks (40-80 business days) for forecasted meters
   c. ERT modules:8-12 weeks (40-60 business days) for forecasted modules
3. National Grid and Itron will meet and/or communicate on a quarterly and semi-annual basis to review the current lead times for each product line. Forecasts and Required Dates will be reviewed and adjusted as lead times change over the term of the agreement.

(6) Taxes and Freight are not included. Prices are in US dollars. Prices are valid through March 31, 2021.

REDACTED

sensus
a xylem brand

DOMESTIC SALES QUOTATION

Customer:	National Grid	Multiple	Quote#	DSQ-100319-10 R1
Address:	Floor C2, 300 Erie Blvd. West, Syracuse, NY 13292		Date:	12/16/19
			Effective:	04/01/20
Attention/Email:			Expires:	03/30/21
Distributor Rep:	Mulcare Pipeline Solutions	Gene Gagliano	Inquiry#	FY Annual 2021
Prepared By:	Bobbie Mohney		End User:	National Grid
Sensus Rep:	Nicholas Stoia	nicholas.stoia@xyleminc.com	Total:	[redacted]

Prices are applicable for shipments from April 01, 2020 through March 30, 2021

	#	Item	QTY (Low) QTY (High)	Price	Extended Price	Lead-Time
ERT Install No NYS Cold Test	1	R275 TC Residential Diaphragm Meter 5 psig MAOP, Temperature Compensated, Ferrule TBA, 2'-1/2' Plastic Index*, Barcoded Customer Bagde or Label (A/R), Customer supplied label installed, Standard Calibration - Data % Accuracy, , Includes Factory Installation and Programming of New Customer Supplied Itron 100G or 500G (programmed in 100G mode), Does Not Include NYS Cold Test *NIMO, Brooklyn, KS - Circular or as specified Boston, Colonial, Narragansett - Direct or as specified	1,000 60,000	[redacted]		20 WK *C0.01P*
ERT Install No NYS Cold Test	2	R275 TC Residential Diaphragm Meter 5 psig MAOP, Temperature Compensated, Ferrule TBA, 2'-1/2' Plastic Index*, Barcoded Customer Bagde or Label (A/R), Customer supplied label installed, Standard Calibration - Data % Accuracy, , Includes Factory Installation and Programming of New Customer Supplied Itron 100G or 500G (programmed in 100G mode), Does Not Include NYS Cold Test *NIMO, Brooklyn, KS - Circular or as specified Boston, Colonial, Narragansett - Direct or as specified	60,001 120,000		$8,263,008.00	20 WK *C0.01P*
ERT Install w/NYS Cold Test	3	R275 TC Residential Diaphragm Meter 5 psig MAOP, Temperature Compensated, Ferrule TBA, 2'-1/2' Plastic Index*, Barcoded Customer Bagde or Label (A/R), Customer supplied label installed, Standard Calibration - Data % Accuracy, Includes Factory Installation and Programming of New Customer Supplied Itron 100G or 500G (programmed in 100G mode), Includes NYS Cold Test *NIMO, Brooklyn, KS - Circular or as specified Boston, Colonial, Narragansett - Direct or as specified	1,000 60,000			20 WK *C0.01P*
ERT Install w/NYS Cold Test	4	R275 TC Residential Diaphragm Meter 5 psig MAOP, Temperature Compensated, Ferrule TBA, 2'-1/2' Plastic Index*, Barcoded Customer Bagde or Label (A/R), Customer supplied label installed, Standard Calibration - Data % Accuracy, Includes Factory Installation and Programming of New Customer Supplied Itron 100G or 500G (programmed in 100G mode), Includes NYS Cold Test *NIMO, Brooklyn, KS - Circular or as specified Boston, Colonial, Narragansett - Direct or as specified	60,001 120,000		$8,884,512.00	20 WK *C0.01P*
ALT: No ERT No NYS Cold Test	5	R275 TC Residential Diaphragm Meter 5 psig MAOP, Temperature Compensated, Ferrule TBA, 2'-1/2' Plastic Index*, Barcoded Customer Bagde or Label (A/R), Customer supplied label installed, Standard Calibration - Data % Accuracy Does not include NYS Cold Test or installation of customer supplied third party AMI device *NIMO, Brooklyn, KS - Circular or as specified Boston, Colonial, Narragansett - Direct or as specified	1,000 60,000			20 WK *C0.01P*
ALT No ERT w/NYS Cold Test	6	R275 TC Residential Diaphragm Meter 5 psig MAOP, Temperature Compensated, Ferrule TBA, 2'-1/2' Plastic Index*, Barcoded Customer Bagde or Label (A/R), Customer supplied label installed, Standard Calibration - Data % Accuracy, Includes Factory Installation and Programming of New Customer Supplied Itron 100G or 500G (programmed in 100G mode), Does not include installation of customer supplied third party AMI device, Includes NYS Cold Test *NIMO, Brooklyn, KS - Circular or as specified Boston, Colonial, Narragansett - Direct or as specified	1,000 60,000			20 WK *C0.01P*
	7					
	8	RT-230 (See DSQ-112818)				

REDACTED

April 24th, 2020 Quote# 3967 rev1

National Grid
326 Ballardvale St.
Wilmington MA 01887 USA

Re: Proposal for Romet Rotary gas meter 2020-2021 requirements

Dear Kirsti Demarco,

Please see the attached quotation for Rotary gas meter requirements as per your request.
We thank you for the opportunity to quote and appreciate for your business.

Note:
1. Meter oil included
2. AMR package (ERT bracket installed, wiring and programming) included in pricing
3. Mechanical back up counter included

Terms:
1. Freight: Prepaid and included for minimum purchase of pallet quantity
2. Prices are in U.S. Funds
3. Net 30 days
4. Duties and taxes are extra
5. **Prices are valid through March 31, 2021**
6. It is Romet's intention to hold prices firm until this proposal expires but should unforeseen events cause transportation or raw materials specifically metals increase, subject to significant change in PPI, BLS, Fuel indexes, Romet reserves the right to request the opportunity to disclose any excessive irregularities, and in turn, may request price adjustments deemed necessary.
7. Please remit PO to: ROMET Limited
   5030 Timberlea Blvd. Mississauga, ON L4W 2S5 Canada
   E-Mail: romet@rometlimited.com

Julie Ahn

Julie Ahn
Manager, Customer Care
Romet Limited
c. Justin Johnson, Brent Collver

ROMET

REDACTED

Quote# 3854 rev1

Meter Size	**AdEM-T Meter Unit Price**
RM1500	[redacted]
RM3000	
RM5000	
RM7000	
RM11000	
RM16000	
RM23000	

Adders

AdEM-T module (stand-alone) w/AMR bracket package	$	[redacted]
AdEM-PTZ module (stand-alone) w/AMR bracket package	$	
AdEM Adaptor kit w/AdEM click	$	
Communication cable PN 41-097-0	$	
Pulse output cable PN 43-035-40	$	
Keyboard Ass'y for AdEM programming PN 46-051-0	$	
Dresser proving cable PN 34-097-40	$	

End of page

Dresser Meters & Instruments
16240 Port Northwest Drive, Suite 100
Houston, TX 77041 USA
T +1 800 521 1114   +1 832 590 2303
F +1 800 335 5224   +1 832 590 2494
www.dresserngs.com

DRESSER NATURAL GAS SOLUTIONS

Proposal for Dresser™ Meters & Instruments Products

To: National Grid 300 Erie Blvd West Syracuse, NY 13202 **ATTN:** Kirsti DeMarco **Email:** Kirsti.DeMarco@nationalgrid.com Copy: Zak Farrell Email: zachary.farrell@nationalgrid.com Copy: Joe McDougle Email: Joseph.McDougle@nationalgrid.com	**Proposal No:** Q1015202 Please refer to proposal number when ordering **Proposal Date:** October 12, 2015 **Proposal Acceptance Validity:** January 12, 2016, (90) days **Seller Contacts:** Diane Fogle Diane Sykes **Phone:** 800-521-1114 **Orders:** Customer Service,	**Rev:** G **Rev Date:** 05/01/2020 Detailed Revision History in Notes below **Proposal Expires:** March 31, 2021 **Email:** **Diane.Fogle@dresserngs.com** **Email:** **Diane.Sykes@dresserngs.com** **FAX:** 832-590-2494 **meters.custcare@dresserngs.com**

Natural Gas Solutions North America, LLC, (hereby known as "Seller"), is pleased to submit this firm proposal to National Grid (hereby known as "Buyer") in response to the *National Grid Doc570567109 Gas & Electric Meter RFP*, for the following Dresser™ Meters and Instruments products:

Please see the specific section for each of the following type of product and their applicable accessories:

- **CD, TC, TC/AMR, TD Series B3 Meters:** (Item No. 1 -50)
- **ES3 Meters with AMR Bracket:** (Item No. 51 -74)
- **Mechanical Pulse Output Meters: ITPWS & ITPWD Meters** (Item No. 75-89)
- **Electronic Pulse Output Meters: ES3 Meters** (Item No. 90-95)
- **IMC/W2-T & IMC/W2-PTZ Meters**: (Item No. 96-130)
- **Bolts & Strainer Gaskets:** (Item No. 131-143)

PRICING EFFECTIVE April 1, 2020 – March 31, 2021

				Net Price Each Without Freight		Net Price Each With Freight	
Item	**QTY**	**N. Grid ID No.**	**Description (See Notes below)**	**With (2) Test Plugs**	**With All Adders***	**With (2) Test Plugs**	**With All Adders***
1.	1	1000433	8C175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), P/N 055207-023.	[redacted]			
2.	1	1000436	8C175 Series B3 Dresser™ Meter, Temperature Compensated (TC), P/N 055207-043.				
3.	1		8C175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint. P/N 058113-643.				
4.	1		8C175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint installed and programmed P/N 058877-643				
5.	1	1000437	8C175 Series B3 Dresser™ Meter, Temperature Compensated with Instrument Drive (TD), P/N 055207-053.				
6.	1	1000406	11C175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), P/N 055209-021.				
7.	1	1000409	11C175 Series B3 Dresser™ Meter, Temperature Compensated (TC), P/N 055209-041.				
8.	1		11C175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for				

National Grid
Attn: Kirsti DeMarco
Dresser Proposal No. Q1015202-REV G
05/01/2020

Dresser Meters & Instruments
16240 Port Northwest Drive, Suite 100
Houston, TX 77041 USA

				Net Price Each Without Freight		Net Price Each With Freight	
Item	QTY	N. Grid ID No.	Description (See Notes below)	With (2) Test Plugs	With All Adders*	With (2) Test Plugs	With All Adders*
			100G Itron® Gas Endpoint, P/N 058114-641.	[redacted]	[redacted]	[redacted]	[redacted]
9.	1		11C175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint installed and programmed P/N *Pending*	[redacted]	[redacted]	[redacted]	[redacted]
10.	1	1000410	11C175 Series B3 Dresser™ Meter, Temperature Compensated with Instrument Drive (TD), P/N 055209-051.	[redacted]	[redacted]	[redacted]	[redacted]
11.	1	1000416	15C175 Series B3 Dresser™ Meter, Counter with Instrument Drive (CD), P/N 055211-022.	[redacted]	[redacted]	[redacted]	[redacted]
12.	1	1000419	15C175 Series B3 Dresser™ Meter, Temperature Compensated (TC), P/N 055211-042.	[redacted]	[redacted]	[redacted]	[redacted]
13.	1		15C175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint, P/N 058115-642.	[redacted]	[redacted]	[redacted]	[redacted]
14.	1		15C175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint installed and programmed P/N 058879-642	[redacted]	[redacted]	[redacted]	[redacted]
15.	1	1000420	15C175 Series B3 Dresser™ Meter, Temperature Compensated with Instrument Drive (TD), P/N 055211-052.	[redacted]	[redacted]	[redacted]	[redacted]
16.	1	1000428	2M175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), P/N 055213-024.	[redacted]	[redacted]	[redacted]	[redacted]
17.	1	1000390	2M175 Series B3 Dresser™ Meter, Temperature Compensated (TC), P/N 055213-044.	[redacted]	[redacted]	[redacted]	[redacted]
18.	1		2M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint, P/N 058116-641.	[redacted]	[redacted]	[redacted]	[redacted]
19.	1		2M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint installed and programmed P/N 061807-644	[redacted]	[redacted]	[redacted]	[redacted]
20.	1	1000391	2M175 Series B3 Dresser™ Meter, Temperature Compensated with Instrument Drive (TD), P/N 055213-054.	[redacted]	[redacted]	[redacted]	[redacted]
21.	1	1000393	3M175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), P/N 055215-022.	[redacted]	[redacted]	[redacted]	[redacted]
22.	1	1000396	3M175 Series B3 Dresser™ Meter, Temperature Compensated (TC), P/N 055215-042.	[redacted]	[redacted]	[redacted]	[redacted]
23.	1		3M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint, P/N ***058117-642***. **Please note corrected Part Number.**	[redacted]	[redacted]	[redacted]	[redacted]
24.	1		3M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for	[redacted]	[redacted]	[redacted]	[redacted]

National Grid
Attn: Kirsti DeMarco
Dresser Proposal No. Q1015202-REV G
05/01/2020

Dresser Meters & Instruments
16240 Port Northwest Drive, Suite 100
Houston, TX 77041 USA

Item	QTY	N. Grid ID No.	Description (See Notes below)	Net Price Each Without Freight		Net Price Each With Freight	
				With (2) Test Plugs	With All Adders*	With (2) Test Plugs	With All Adders*
			100G Itron® Gas Endpoint installed and programmed P/N 058881-642	[redacted]			
25.	1	1000397	3M175 Series B3 Dresser™ Meter, Temperature Compensated with Instrument Drive (TD), P/N 055215-052.				
26.	1	1000399	5M175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), P/N 055217-023.				
27.	1	1000402	5M175 Series B3 Dresser™ Meter, Temperature Compensated (TC), P/N 055217-043.				
28.	1		5M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint, P/N ***058118-643*****.** **Please note corrected Part Number.**				
29.	1		5M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint installed and programmed P/N 058882-643				
30.	1	1000403	5M175 Series B3 Dresser™ Meter, Temperature Compensated with Instrument Drive (TD), P/N 055217-053.				
31.	1	1000404	7M175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), P/N 055219-023.				
32.	1	1000431	7M175 Series B3 Dresser™ Meter, Temperature Compensated (TC), P/N 055219-043.				
33.	1		7M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint, P/N 058119-643.				
34.	1		7M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint installed and programmed P/N 058883-643				
35.	1	1000432	7M175 Series B3 Dresser™ Meter, Temperature Compensated with Instrument Drive (TD), P/N 055219-053.				
36.	1	1000411	11M175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), P/N 055221-023.				
37.	1	1000414	11M175 Series B3 Dresser™ Meter, Temperature Compensated (TC), P/N 055221-043.				
38.	1		11M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint, P/N 058120-643.				
39.	1		11M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint installed and programmed P/N *Pending*				
40.	1	1000415	11M175 Series B3 Dresser™ Meter, Temperature Compensated with Instrument Drive (TD),				

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				Net Price Each Without Freight		Net Price Each With Freight	
Item	**QTY**	**N. Grid ID No.**	**Description (See Notes below)**	**With (2) Test Plugs**	**With All Adders***	**With (2) Test Plugs**	**With All Adders***
			P/N 055221-053.				
41.	1	1000421	16M175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), P/N 055223-024.	[redacted]			
42.	1	1000424	16M175 Series B3 Dresser™ Meter, Temperature Compensated (TC), P/N 055223-044.				
43.	1		16M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint, P/N 058121-644.				
44.	1		16M175 Series B3 Dresser™ Meter, Temperature Compensated Version, with AMR Adapter Kit for 100G Itron® Gas Endpoint installed and programmed P/N 058885-644				
45.	1	1000425	16M175 Series B3 Dresser™ Meter, Temperature Compensated with Instrument Drive (TD), P/N 055223-054.				
46.	1	1000427	23M232 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), 4" flanged connections, P/N 056578-021.				
47.	1	1000426	23M175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), 6" flanged connections, P/N 055225-021.				
48.	1	1000392	38M175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), P/N 055227-022.				
49.	1	1000398	56M175 Series B3 Dresser™ Meter, Counter With Instrument Drive (CD), P/N 055229-021.				
50.	1		102M125 Series A1 Dresser™, Counter with Instrument Drive Version, Side Inlet, P/N 048646-300.				
ES3 METER WITH AMR MOUNTING BRACKET: (See Item No. 70-74 for Optional Items)							
51.	1		8C175 Series B Dresser™ Meter with ES3 Electronic TC and Mechanical S3 Counter, complete with Itron 100G AMR Bracket, P/N 060274-061.	[redacted]			
52.	1		11C175 Series B Dresser™ Meter with ES3 Electronic TC and Mechanical S3 Counter, complete with Itron 100G AMR Bracket, P/N 060275-061.				
53.	1		15C175 Series B Dresser™ Meter with ES3 Electronic TC and Mechanical S3 Counter, complete with Itron 100G AMR Bracket, P/N 060276-062.				
54.	1		2M175 Series B Dresser™ Meter with ES3 Electronic TC and Mechanical S3 Counter, complete with Itron 100G AMR Bracket, P/N 060277-064.				
55.	1		3M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, complete with Itron 100G AMR Bracket, P/N 060278-062.				

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Item	QTY	N. Grid ID No.	Description (See Notes below)	Net Price Each Without Freight: With (2) Test Plugs	Net Price Each Without Freight: With All Adders*	Net Price Each With Freight: With (2) Test Plugs	Net Price Each With Freight: With All Adders*
56.	1		5M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, complete with Itron 100G AMR Bracket, P/N 060279-063.	[redacted]			
57.	1		7M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, complete with Itron 100G AMR Bracket, P/N 060280-063.				
58.	1		11M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, complete with Itron 100G AMR Bracket, P/N 060281-063.				
59.	1		16M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, complete with Itron 100G AMR Bracket, P/N 060282-064.				
60.	1		Price Adder to above with AMR Bracket prices for Dresser™ to install and program a customer supplied Itron 100G Remote Gas Endpoint to National Grid specifications.				
ES3 METER WITH AMR MOUNTING BRACKET, WITH 100G ERT INSTALLED AND PROGRAMMED: (See Item No. 70-74 for Optional Items)							
61.	1		8C175 Series B Dresser™ Meter with ES3 Electronic TC and Mechanical S3 Counter, complete with Itron AMR Bracket and Remote ERT Installed and Programmed, P/N 060274-061.	[redacted]			
62.	1		11C175 Series B Dresser™ Meter with ES3 Electronic TC and Mechanical S3 Counter, complete with Itron AMR Bracket and Remote ERT Installed and Programmed, P/N Pending.				
63.	1		15C175 Series B Dresser™ Meter with ES3 Electronic TC and Mechanical S3 Counter, complete with Itron AMR Bracket and Remote ERT Installed and Programmed, P/N 060276-642.				
64.	1		2M175 Series B Dresser™ Meter with ES3 Electronic TC and Mechanical S3 Counter, complete with Itron AMR Bracket and Remote ERT Installed and Programmed, P/N 060277-064.				
65.	1		3M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, complete with Itron AMR Bracket and Remote ERT Installed and Programmed, P/N 060278-642.				
66.	1		5M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, complete with Itron AMR Bracket and Remote ERT Installed and Programmed, P/N 060279-643.				
67.	1		7M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, complete with Itron AMR Bracket and Remote ERT Installed and Programmed, P/N 060280-643.				

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				Net Price Each Without Freight		Net Price Each With Freight	
Item	**QTY**	**N. Grid ID No.**	**Description (See Notes below)**	**With (2) Test Plugs**	**With All Adders***	**With (2) Test Plugs**	**With All Adders***
68.	1		11M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, complete with Itron AMR Bracket and Remote ERT Installed and Programmed, P/N 060281-643.	[redacted]			
69.	1		16M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, complete with Itron AMR Bracket and Remote ERT Installed and Programmed, P/N 060282-644.				
			ES3 ADDITIONAL AND OPTIONAL ITEMS	**Net Price Each Without Freight**		**Net Price Each With Freight**	
70.	1		Male Mating Circular Connector without Cable, P/N 012198-009.	[redacted]			
71.	1		Pulse Output Mating Cable Assemblies with Male Mating Circular Connector. Specify cable length and part number when ordering. a. 5' Cable with Male CIR Connector, P/N 056922-003. b. 10' Cable with Male CIR Connector, P/N 056922-004. c. 20' Cable with Male CIR Connector, P/N 056922-005.				
72.	1		PC to D800/ES3/ETC Communications Package -- includes Magnet for Screen Scroll, 6' USB Cable, IR Interface, D800 IR Holder, and ES3/ETC IR Holder, P/N 060542-000.				
73.	1		D800/ES3/ETC MeterWare Software – required to communicate with ES3. Software package provided at No Charge to first time buyers. Comms Cable required for use with Software (not included).				
74.	1		IRDA Cable Model 5 Prover Cable Kit – required for proving the ES3. P/N 060832-000.				

Notes: Part numbers shown above are for 100G, & 2.4Ghz Remote Itron Gas Endpoints.
Contact Factory to confirm ES3 configuration to National Grid specifications.
Consult Factory for pricing for installation of remote gas endpoints other than Itron brand.
National Grid pays freight to ship remote gas endpoint to Houston Factory
All Brooklyn Union meters include two differential test plugs, installed and two Rockseals installed.

MECHANICAL PULSE OUTPUT METERS: ITPWS & ITPWD METERS: (See Item No. 87-89 for Optional Items)

ITPWS MECHANICAL SINGLE PULSE OUTPUT METERS

75.	1		15C175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser, Single Pulse Output, ITPWS, Cable Gland Connection with 4" Pigtail, Class I, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057252-332.	[redacted]			

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				Net Price Each Without Freight		Net Price Each With Freight	
Item	**QTY**	**N. Grid ID No.**	**Description (See Notes below)**	**With (2) Test Plugs**	**With All Adders***	**With (2) Test Plugs**	**With All Adders***
76.	1		3M175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser, Single Pulse Output, ITPWS, Cable Gland Connection with 4” Pigtail, Class I, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057258-332.	[redacted]			
77.	1		5M175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser, Single Pulse Output, ITPWS, Cable Gland Connection with 4” Pigtail, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057261-333.	[redacted]			
78.	1		7M175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser, Single Pulse Output, ITPWS, Cable Gland Connection with 4” Pigtail, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057264-333.	[redacted]			
79.	1		11M175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser, Single Pulse Output, ITPWS, Cable Gland Connection with 4” Pigtail, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057268-333.	[redacted]			
80.	1		16M175 Series B3 Dresser™ Meter, ITPWS, Temperature Compensated with Pulser, Single Pulse Output, Cable Gland Connection with 4” Pigtail, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057270-334.	[redacted]			
Note: Mechanical TC Pulser Not Available for Meter Sizes over 16M175. For Alternate Options, See *Model IMC/W2- T+Log*, Item No. 96-100.							
ITPWD MECHANICAL DUAL PULSE OUTPUT METERS							
81.	1		15C175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser Dual Pulse Output, ITPWD, Cable Gland Connection with 4” Pigtail, Class I, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057252-341.	[redacted]			
82.	1		3M175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser Dual Pulse Output, ITPWD, Cable Gland Connection with 4” Pigtail, Class I, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057258-340.	[redacted]			
83.	1		5M175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser Dual Pulse Output, ITPWD, Cable Gland Connection with 4” Pigtail, Class I, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057261-343.	[redacted]			
84.	1		7M175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser Dual Pulse Output, ITPWD, Cable Gland Connection with 4” Pigtail, Class I, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40	[redacted]			

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				Net Price Each Without Freight		Net Price Each With Freight	
Item	QTY	N. Grid ID No.	Description (See Notes below)	With (2) Test Plugs	With All Adders*	With (2) Test Plugs	With All Adders*
			C <= Ta <= +60 C, P/N 057264-343.				
85.	1		11M175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser Dual Pulse Output, ITPWD, Cable Gland Connection with 4" Pigtail, Class I, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057268-343.	[redacted]			
86.	1		16M175 Series B3 Dresser™ Meter, Temperature Compensated with Pulser Dual Pulse Output, ITPWD, Cable Gland Connection with 4" Pigtail, Class I, Zone 0, AEx ia IIC T4 Ga Class I, Zone 0, Ex ia IIC T4 Ga -40 C <= Ta <= +60 C, P/N 057270-344.				
Note: Mechanical TC Pulser Not available for Meter Sizes over 16M175. For Alternate Options, See *Model IMC/W2- T+Log*, Item No. 96-100.							
			ITPWS & ITPWD ADDITIONAL AND OPTIONAL ITEMS	Net Price Each Without Freight		Net Price Each With Freight	
87.	1		AMR Mounting Adaptor for Pulser Meter, P/N Pending.	[redacted]			
88.	1		Adder to install Itron 100G ERT				
89.	1		Adder to Install & Program Itron 100G ERT				
ES3 ELECTRONIC PULSE OUTPUT METERS (For Both Single and Dual Pulse Output) (See Item No. 70-74 for Optional Items)							
90.			15C175 Series B Dresser™ Meter with ES3 Electronic TC and Mechanical S3 Counter, P/N 060276-042.	[redacted]			
91.			3M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, P/N 060278-042.				
92.			5M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, P/N 060279-043.				
93.			7M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, P/N 060280-043.				
94.			11M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, P/N 060281-043.				
95.			16M175 Series B Dresser™ Meter with ES3 Electronic TC and S3 Mechanical Counter, P/N 060282-044.				
Note: ES3 is Not Available for Meter Sizes over 16M175. For Alternate Options, See *Model IMC/W2- T+Log*, Item No. 96-100.							
IMC/W2-T METERS: (See Item No. 124-130 for Optional Items)							

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Item	**QTY**	**N. Grid ID No.**	**Description (See Notes below)**	**With (2) Test Plugs**	**With All Adders***	**With (2) Test Plugs**	**With All Adders***
96.	1		8C175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Internally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.	[redacted]			
97.	1		11C175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Internally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
98.	1		15C175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Internally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
99.	1		2M175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Internally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
100.	1		3M175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Internally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
101.	1		5M175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Internally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
102.	1		7M175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Internally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
103.	1		11M175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Internally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
104.	1		16M175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Internally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
105.	1		23M232 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Externally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
106.	1		23M175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Externally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
107.	1		38M175 Series B Dresser™ Meter, Model IMC/W2-T+Log, with Externally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				

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				Net Price Each Without Freight		Net Price Each With Freight	
Item	QTY	N. Grid ID No.	Description (See Notes below)	With (2) Test Plugs	With All Adders*	With (2) Test Plugs	With All Adders*
108.	1		56M175Series B Dresser™ Meter, Model IMC/W2-T+Log, with Externally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.	[redacted]			
109.	1		102M125 Series A1 Dresser™ Meter, Model IMC/W2-T+Log, with Externally Mounted Temperature Probe, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
IMC/W2-PTZ METERS: (See Item No. 124-130 for Optional Items)							
110.	1		8C175 Series B Dresser™ Meter, Model IMC/W2-PTZ+Log, with Internally Mounted Temperature Probe, choice of Internal or External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.	[redacted]			
111.	1		11C175 Series B Dresser™ Meter, Model IMC/W2-PTZ+Log, with Internally Mounted Temperature Probe, choice of Internal or External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
112.	1		15C175 Series B Dresser™ Meter, Model IMC/W2-PTZ+Log, with Internally Mounted Temperature Probe, choice of Internal or External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
113.	1		2M175 Series B Dresser™ Meter, Model IMC/W2-PTZ+Log, with Internally Mounted Temperature Probe, choice of Internal or External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
114.	1		3M175 Series B Dresser™ Meter, Model IMC/W2-PTZ+Log, with Internally Mounted Temperature Probe, choice of Internal or External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
115.	1		5M175 Series B Dresser™ Meter, Model IMC/W2-PTZ+Log, with Internally Mounted Temperature Probe, choice of Internal or External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
116.	1		7M175 Series B Dresser™ Meter, Model IMC/W2-PTZ+Log, with Internally Mounted Temperature Probe, choice of Internal or External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				

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Item	QTY	N. Grid ID No.	Description (See Notes below)	Net Price Each Without Freight: With (2) Test Plugs	Net Price Each Without Freight: With All Adders*	Net Price Each With Freight: With (2) Test Plugs	Net Price Each With Freight: With All Adders*
117.	1		11M175 Series B Dresser ™ Meter, Model IMC/W2-PTZ+Log, with Internally Mounted Temperature Probe, choice of Internal or External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.	[redacted]			
118.	1		16M175 Series B Dresser ™ Meter, Model IMC/W2-PTZ+Log, with Internally Mounted Temperature Probe, choice of Internal or External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
119.	1		23M232 Series B Dresser ™ Meter, Model IMC/W2-PTZ+Log, with Externally Mounted Temperature Probe, External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
120.	1		23M175 Series B Dresser ™ Meter, Model IMC/W2-PTZ+Log, with Externally Mounted Temperature Probe, External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
121.	1		38M175 Series B Dresser ™ Meter, Model IMC/W2-PTZ+Log, with Externally Mounted Temperature Probe, External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
122.	1		56M175 Series B Dresser ™ Meter, Model IMC/W2-PTZ+Log, with Externally Mounted Temperature Probe, External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
123.	1		102M125 Series A1 Dresser ™ Meter, Model IMC/W2-PTZ+Log, with Externally Mounted Temperature Probe, External Line Pressure Connection, Single Circular Pulse Output Connector and Sealed Lithium Battery Pack.				
			IMC/W2 ADDITIONAL AND OPTIONAL ITEMS	Net Price Each Without Freight		Net Price Each With Freight	
124.	1		Micro Corrector User Terminal Software, P/N 057446-070.	[redacted]			
125.	1		Serial Communications Cable, PC to IMC P/N 057135-001.				
126.	1		USB to Serial Converter Kit, P/N 059850-000.				
127.	1		Smart Prove Kit for Model 5 Prover, P/N 058860-100.				

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Item	QTY	N. Grid ID No.	Description (See Notes below)	With (2) Test Plugs	With All Adders*	With (2) Test Plugs	With All Adders*
128.	1		Pressure/Valve Piping Kit for IMC/W2 meters with External Pressure connection, P/N 051416-320.	[redacted]			
129.	1		Thermowell Options for External Temperature IMC/W2 meters: Thermowell • 2" Long, 1" NPT - P/N 050784-002 • 4" Long, 1" NPT - P/N 050784-001 • 6" Long, 1" NPT - P/N 050784-000				
130.	1		Cable and Mount Itron 100G Remote ERT to the back of the IMC/W2 and factory program the ERT to NGRID specifications: Kit Mounting ITRON 100G Corrector D/E MALE CONN L=1FT IMCW2, P/N 059726-610.				
Coated Flange Bolts and Gasket Strainers							
131.	1	1000438	Kit, For 8C175 Series B3 Dresser™ Meter: (8) Coated Flange Bolts, P/N 010044-003 and (1) Gasket Strainer, P/N 054268-003				
132.	1	1000439	Kit, For 11C175 Series B3 Dresser™ Meter: (8) Coated Flange Bolts, P/N 010044-003 and (1) Gasket Strainer, P/N 054268-003				
133.	1	1000440	Kit, For 15C175 Series B3 Dresser™ Meter: (8) Coated Flange Bolts, P/N 010044-003 and (1) Gasket Strainer, P/N 054268-003				
134.	1	1000441	Kit, For 2M175 Series B3 Dresser™ Meter: (8) Coated Flange Bolts, P/N 010044-003 and (1) Gasket Strainer, P/N 054268-003				
135.	1	1000442	Kit, For 3M175 Series B3 Dresser™ Meter: (8) Coated Flange Bolts, P/N 010044-004 and (1) Gasket Strainer, P/N 054268-003				
136.	1	1000443	Kit, For 5M175 Series B3 Dresser™ Meter: (8) Coated Flange Bolts, P/N 010044-004 and (1) Gasket Strainer, P/N 054268-004				
137.	1	1000444	Kit, For 7M175 Series B3 Dresser™ Meter: (8) Coated Flange Bolts, P/N 010044-004 and (1) Gasket Strainer, P/N 054268-004				
138.	1	1000445	Kit, For 11M175 Series B3 Dresser™ Meter: (16) Coated Flange Bolts, P/N 010044-004 and (1) Gasket Strainer, P/N 054268-005				
139.	1	1000446	Kit, For 16M175 Series B3 Dresser™ Meter: (16) Coated Flange Bolts, P/N 010044-004 and (1) Gasket Strainer, P/N 054268-005				
140.	1	1000447	Kit, For 23M232 Series B3 Dresser™ Meter: (16) Coated Flange Bolts, P/N 010044-004 and (1) Gasket Strainer, P/N 054268-005				

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Item	QTY	N. Grid ID No.	Description (See Notes below)	With (2) Test Plugs	With All Adders*	With (2) Test Plugs	With All Adders*
141.	1	1000448	Kit, For 23M175 Series B3 Dresser™ Meter: (16) Coated Flange Bolts, P/N 010194-107 and (1) Gasket Strainer, P/N 054268-006	[redacted]			
142.	1	1000449	Kit, For 38M175 Series B3 Dresser™ Meter: (16) Coated Flange Bolts, P/N 010194-107 and (1) Gasket Strainer, P/N 054268-006				
143.	1	1000450	Kit, For 56M175 Series B3 Dresser™ Meter: (16) Coated Flange Bolts, P/N 010194-107 and (1) Gasket Strainer, P/N 054268-007				
* **Note:** *Net Price with All Adders includes two differential test plugs, coated flange bolts and strainer gasket.*							

Proposal Validity: 90 days.

Material Specifications: Reference *Agreement between National Grid and Dresser, Inc., Roots Meters & Instruments for Gas Rotary Meters, Contract No. for PeopleSoft: GAO6DRESSER02CLB, Blanket PO No. for Oracle: 585710, January 14, 2010.*

Pricing Policy: Prices are firm for one year, for shipments requested *April 1, 2020, through March 31, 2021*

Payment Terms: Net Cash 30 Days from invoice date.

Delivery Time: Subject to lead-time in effect when order received.
Current lead-times for 8C175 – 5M175 CTR/CD Series B meters are:
7 to 9 weeks (less than 100), consult factory for larger orders, ARO
Current lead-times for 8C175 – 5M175 TC/TD Series B meters are:
8 to 10 weeks (less than 50), consult factory for larger orders, ARO
Current lead-times for 7M175 – 23M232 CTR/CD Series B meters are:
7 to 9 weeks (less than 30), consult factory for larger orders, ARO
Current lead-times for 7M175 – 16M175 TC/TD Series B meters are:
8 to 10 weeks (less than 30), consult factory for larger orders, ARO
Current lead-times for 23M175 – 56M175 meters are:
4 to 6 weeks (less than 6), consult factory for larger orders, ARO
Consult factory for lead time for 102M125 meters
Current lead-times for Bolts and Gasket Strainers, 4-6 weeks, ARO
For lead-time on ES3's, IMC/W2-T, IMC/W2-PTZ, ITPWS & ITPWD consult Factory
Factory lead-time does not include transit time.

Delivery Terms: CIP Destination - Prepaid and Allowed or CIP Shipping Point – Purchaser Pays Freight (as agreed upon at time of Purchase order)

TRS Compliance: Due to certain compliance and due diligence requirements, all customer/regional/country regulatory requirements must be reviewed and complied with before shipping products. Product lead-time begins after the compliance due diligence process is complete.

Terms and Conditions: This Proposal is subject to the terms and conditions of the *Agreement between National Grid and Dresser, Inc., Roots Meters & Instruments for Gas Rotary Meters, Contract No. for PeopleSoft: GAO6DRESSER02CLB, Blanket PO No. for Oracle: 585710, January 14, 2010, Terms and Conditions Amended August 19, 2013*, and no other terms shall apply, unless agreed upon by the parties in writing, and attached hereto.

National Grid
Attn: Kirsti DeMarco
Dresser Proposal No. Q1015202-REV G
05/01/2020

Dresser Meters & Instruments
16240 Port Northwest Drive, Suite 100
Houston, TX 77041 USA

Confidentiality Statement: This entire (commercial and technical) proposal and the correspondence and communications concerning this proposal (collectively the "Proposal") developed by Seller and provided to Buyer are the property of Seller. The proposal and the information contained herein is furnished to Buyer with the understanding that it will not, without the prior consent of Seller be used for any purposes other than in connection with the evaluation of Seller's proposal. In no event shall the proposal or any information contained therein be disclosed to any third party without the prior written consent of Seller. The proposal contains information that is confidential and proprietary to Seller, including, without limitation, information relating to design, price, payment terms, and warranty. Buyer agrees to return the proposal and all copies or extracts thereof upon written request from Seller. This proposal document is proprietary to Seller and is furnished in confidence solely for use in considering the merits of the proposal and for no other direct or indirect use. By accepting this document from Seller, the recipient agrees:

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2. To avoid publication or other unrestricted disclosure of this document or the information it contains.
3. To return this document upon the request of Seller.

Additional Clarifications and Notes:

1. Purchase Order Submission: A purchase order or a letter of acceptance is required as written notification of acceptance of this Proposal. Please ensure that your **purchase order reflects the Proposal number** and is issued **Natural Gas Solutions North America, LLC**.
2. A sufficient quantity of oil for the initial filling is packed with each meter at no charge (5C/8C15 do not use oil).
3. Revision History: REV A: Revised 3/07/16 to add Single & Dual Pulse Output Meters. REV A was submitted only in a Spreadsheet format.

   REV B: Revised 5/20/16 to add Pulse Output meters from REV A spreadsheet to this format and add, INVENSYS AMR meters, Bolts and Gasket Strainers.

   REV C: Revised 2/24/17 to extend pricing through March 31, 2018.

   REV D: Revised to remove TC/AMR 40G ERT Items and update pricing effective June 18, 2018 through March 31, 2019.

   REV E: Revised 3/28/19 to update pricing effective June 1, 2019 through March 31, 2020.

   REV F: Revised 8/16/2019 to add TC AMR ERT P/I.

   REV G: Revised for an additional year
4. **Warranty:** The warranty for the Dresser™ IMC/W2 accessory unit shall expire four (4) years from delivery, except that the software is warranted for ninety (90) days from delivery. The lithium battery pack for the Dresser™ IMC/W2 accessory unit has a separate warranty. The 4-year warranty applies to the IMC/W2 accessory unit only.

   The warranty for Dresser ES3 and Dresser ETC accessory units shall expire four (4) years from delivery, except that software is warranted for ninety (90) days from delivery. The 4-year warranty applies to the accessory unit only. Battery packs for the Dresser ES3 and Dresser ETC products have a separate warranty which expires twelve (12) years from delivery.

   See the *Agreement between National Grid and Dresser, Inc., Roots Meters & Instruments for Gas Rotary Meters, Contract No. for PeopleSoft: GAO6DRESSER02CLB, Blanket PO No. for Oracle: 585710, January 14, 2010, Terms and Conditions Amended August 19, 2013* for meter warranty.
5. **Freight:** For meter with ERT installed, National Grid to supply American Style Itron ERT. Customer pays freight to ship Itron ERT to Houston factory. Meter shipments are CIP destination with freight prepaid and allowed.
6. Prior to shipping Itron ERTs to Houston (or having Itron drop ship them), we request that you **call your Sales Support Specialist on our toll-free number (1-800-521-1114) to request a reference number** so we can track the Itron ERTs internally once they reach our dock.
7. The Dresser™ Meters and Instruments AMR Adapter Kits identified above and/or their use may be protected by one of more of the following United States Patents: 7,059,200; 7,117,737; 7,290,456 and 7,533,581.

National Grid
Attn: Kirsti DeMarco
Dresser Proposal No. Q1015202-REV G
05/01/2020

Dresser Meters & Instruments
16240 Port Northwest Drive, Suite 100
Houston, TX 77041 USA

Please Note: Our AMR Adapter Kit has been thoroughly tested and confirmed to properly mount the specified AMR device onto your Dresser™ Meter when installed in accordance with factory installation instructions. Dresser shall not be held liable for any damage to the meter, AMR adapter kit, or AMR device due to improper installation by the customer or subcontractor. Should any problems be encountered with a meter and/or AMR device that is not attributed to the Dresser™ AMR Adapter Kit, Dresser reserves the right to not accept its return for credit or exchange.

For further information, contact our general offices in Houston at 1-800-521-1114, or our representatives serving your area, Randy Ross, at 401-413-5519 or Albert Apicella, at 919-452-7541. For ordering information, please contact Diane Fogle, Sr. Sales Support Specialist, or Diane Sykes, at 1-800-521-1114.

We sincerely appreciate your interest in our products.

REDACTED

Electric / Gas / Water
Information collection, analysis and application
Itron, Inc.
2111 North Molter Road
Liberty Lake, WA 99019
fax: 866-787-6910
customer.orders@itron.com

Pricing Summary for

National Grid

January 21, 2020
BMR# 19081-19 Ver1 Jan

Diaphragm Gas Meters

Item	Part Number	Description	Qty	Unit Price	Extended Price	Notes
1	MXXXXX-I250TC	I-250 - Temperature Compensated 250 Class Meter	6,000	[redacted]		
2	250ERTINSTALL	Assembly and Installation of Itron 100G Datalogging ERT	TBD			
3		Additional Fee For Programming of Itron Gas Module	TBD			
4	MXXXXX-400ATC	400A - Temperature Compensated 400 Class Meter	1,800			
5	400AERTINSTALL	Assembly and Installation of Itron 100G Datalogging ERT Modu	TBD			
6		Additional Fee For Programming of Itron Gas Module	TBD			
7	MXXXXX-800ATC	800A - Temperature Compensated 800 Class Meter	500			
8	COMMERTINSTALL	Assembly and Installation of Itron 100G Datalogging ERT Modu	TBD			
9		Additional Fee For Programming of Itron Gas Module	TBD			
10	MXXXXX-1000ATC	1000A - Temperature Compensated 1000 Class Meter	600			
11	COMMERTINSTALL	Assembly and Installation of Itron 100G Datalogging ERT Modu	TBD			
12		Additional Fee For Programming of Itron Gas Module	TBD			

Diaphragm Gas Meters 100G Module

Item	Part Number	Description	Qty	Unit Price	Extended Price	Notes
1	M04051-I250TCI-B	I-250 - Temperature Compensated 250 Class Meter with Itron Residential Gas Module assembled, installed, and programmed and ordered as one line item on customer PO using the -B part number provided by Itron.	TBD			
2	M04046-I250TCI-B	I-250 - Temperature Compensated 250 Class Meter with Itron Residential Gas Module assembled, installed, and programmed and ordered as one line item on customer PO using the -B part number provided by Itron.	TBD			
3	M53082-400ATCI-B	400A - Temperature Compensated 400 Class Meter with Itron Residential Gas Module assembled, installed, and programmed and ordered as one line item on customer PO using the -B part number provided by Itron.	TBD			
4	M53085-400ATCI-B	400A - Temperature Compensated 400 Class Meter with Itron Residential Gas Module assembled, installed, and programmed and ordered as one line item on customer PO using the -B part number provided by Itron.	TBD			
5	M53097-400ATCI-B	400A - Temperature Compensated 400 Class Meter with Itron Residential Gas Module assembled, installed, and programmed and ordered as one line item on customer PO using the -B part number provided by Itron.	TBD			
6	M39022-800ATCI-B	800A - Temperature Compensated 800 Class Meter with Itron Commercial Gas Module assembled, installed, and programmed and ordered as one line item on customer PO using the -B part number provided by Itron.	TBD			
7	M39023-800ATCI-B	800A - Temperature Compensated 800 Class Meter with Itron Commercial Gas Module assembled, installed, and programmed and ordered as one line item on customer PO using the -B part number provided by Itron.	TBD			
8	M39024-800ATCI-B	800A - Temperature Compensated 800 Class Meter with Itron Commercial Gas Module assembled, installed, and programmed and ordered as one line item on customer PO using the -B part number provided by Itron.	TBD			
9	M51054-1000ATCI-B	1000A - Temperature Compensated 1000 Class Meter with Itron Commercial Gas Module assembled, installed, and programmed and ordered as one line item on customer PO using the -B part number provided by Itron.	TBD			
10	M51059-1000ATCI-B	1000A - Temperature Compensated 1000 Class Meter with Pete's Plug with Itron Commercial Gas Module assembled, installed, and programmed and ordered as one line item on customer PO using the -B part number provided by Itron.	TBD			
11	20DEGREETEST	20 Degree Cold Box Testing Fee Per Diaphragm Meter (This line item is optional and will be charged per meter only if National Grid requires Itron to supply 20 Degree Testing Data)	TBD			
		Total				

Notes and Assumptions

(1) Above pricing for diaphragm meters does not include swivels, connections nuts, and washers. Itron can quote these separately if required.

(2) Itron recommends the sampling plan ANSI Z1.4, General level II, AQL 2.5 for incoming testing.

(3) All diaphragm meters are built and tested in accordance to ANSI B109 to meet all performance requirements of this industry standard.

(4) Delivery pending successful correlation between Itron's and Customer's proving equipment unless correlation is waived.

(5) The above pricing is for bulk packing only. Itron's standard pack configuration is shown in the table below. Please use full pallet quantities when possible.

	Meters Per Layer	Layers per Pallet	Meters per Pallet	Pallet Dimensions	Pallet Weight (lbs)
I-250	20	3	60	44 x 42 x 50	670
I-250 w/ 100G	16	3	48	44 x 42 x 50	604
400A	20	3	60	48 x 46 x 53	906
400A w/ 100G	16	3	48	48 x 46 x 53	785
675A/800A/1000A	9	2	18	48 x 46 x 65	845
675A/800A/1000A w/ 100G	9	2	18	48 x 46 x 65	905

(6) Additional fees will apply for custom badges and / or labels that are required to be provided by Itron. Itron must have customer defined meter serial numbers for annual requirements no later than 6 weeks prior to first scheduled ship date.

(7) Itron will apply/affix one customer-provided badge or label free of charge. An additional charge of $0.10 per meter per badge or label will apply for quantities greater than one. All badges or labels provided by the customer needs to be approved by Itron for proper fit on meters. Customer provided stickers must be delivered to the Itron facility a minimum of 6 weeks prior to ship date to guarantee on-time delivery.

(8) Pricing is based on existing agreements or Itron's standard terms and conditions.

(9) Taxes and freight are not included. Freight is FOB Shipping Point, Prepay and Add. Prices are in US dollars. Prices are valid April 1, 2020 through March 31, 2021.

PUC 6-21A

Request:

Referring to PUC 3-6, page 2 and the "Comments" relating to Purchased Meters, (a) please explain the criteria used by the Company to determine how many meters it must have in inventory to maintain a sufficient number, (b) please explain how the Company determined that it would need 12,450 meters in inventory by the end of FY 2022 as reflected in PUC 3-22, (c) please provide a breakdown of the meters by "size" which the Company estimates it will have in inventory by the end of FY 2022, and (c) please explain whether the Company uses the same criteria in its Massachusetts and New York jurisdictions for determining the number of meters it needs to have in inventory to meet the requirement of having a sufficient number of meters in inventory.

Response:

a) Please refer to PUC 3-24 for year-to-year inventory and purchase strategy.

b) Per the Company's amended response to PUC 3-22, the ending inventory for FY 2022 is 7,398 meters.

c) The Company is unable to breakdown the forecasted ending inventory for FY 2022 because it cannot predict exactly which meters will be changed within the year. Actual meter changes rely on gaining access to the customer's premise. The Company is only successful at gaining access to a limited percentage of premises after exhausting the process of getting in contact with the customer. Please note that the Company satisfies its regulatory requirements as long as it exhausts its efforts to contact customers. If the Company is not successful through callings and door hangers, the Company moves to another premise, while adding the unsuccessful attempts to the backlog of meters to be changed the following year. Without being able to forecast exactly which customers will allow access to their premises, the Company cannot forecast exactly which meter makes and models will be needed.

d) The Company complies with different regulatory requirements in other jurisdictions, which influences the total number of meters needed in inventory at a given time.

   Massachusetts requires a seven-year interval meter change program. Massachusetts also experiences access issues with customers, preventing the Company from forecasting exact inventory needs throughout the year. As a result, inventory levels are kept high to mitigate the potential increase in meter demand if customers' appointments are uncharacteristically successful. Without the Company knowing exactly which customers will allow access to their premises, the Company cannot predict which specific meter make and model will be exchanged.

New York follows a meter accuracy testing program that requires only a small sample of meters to be replaced, which provides an indication of meter performance for the entire population. Meters requiring replacement are known by meter make and model, with the Company requesting access to specific customers based on that meter make and model. With the total number of meters changed based on the make and model, and not the specific customer, the Company has a more controllable dependency on how to manage inventory levels at a more granular level. In addition to more controllable variables of meter change forecasts, the Company is also allowed to shutoff service to customers who do not allow access for meter changes.

PUC 6-21B

Request:

Referring to Attachment PUC 3-10, (a) please explain why the Company originally proposed a meter purchase budget to the Division in September 2020 of $6,880,000. (b) Please explain why the proposal dropped to $4,480,000 on October 1, 2020. (c) Please explain why the Company was able to agree to a final budget of $2,880,000 (compared to the original $6.8 million), given regulatory requirements and the Company's meter purchasing criteria.

Response:

(a) The proposed Meter Purchase budget of $6,880,000 in September planned for the purchase of 26,244 meters for use in FY 2022. The COVID-19 Pandemic significantly reduced the volume of meters replaced in FY 2021. Therefore, an increase was initially planned for FY 2022 to make up for the FY 2021 shortfall.

(b) On October 1, 2020, the meter purchase plan was reduced to a more realistic 18,600 meters to better align with the overall long-term meter replacement strategy of creating a level year-over-year plan. Planning for a relatively level replacement rate each year will allow the Company to better manage resources and materials year-over-year and will create a level long-term plan to meet Company and regulatory requirements going forward. The reduction of 7,600 meter purchases reduced the budget by $2,000,000 reduction, resulting in a new budget of $4,880,000.

(c) The Company was able to further reduce the FY 2022 budget proposal by pulling an additional $2,000,000 forward into FY 2021 to pre-purchase meters. The overall decrease in work and associated underspend for FY 2021, coupled with the favorable pricing currently in place, allowed the Company to pre-purchase approximately 9,000 additional meters at a discount of approximately 30% versus the pricing increase anticipated for FY 2022. The Company will use the final proposed budget amount of $2,880,000 for FY 2022 to purchase the remaining 9,600 meters that will be required to complete the FY 2022 meter replacement plan.

Prepared by or under the supervision of: Stephanie Eddleston

PUC 6-22

Request:

Referring to the response to PUC 3-21, please explain whether the year-ending meter inventory levels shown for FY 17 through FY 20 met the Company's criteria for having a sufficient number of meters in inventory, as referenced in PUC 3-6, page 2. If yes, please explain why the Company is proposing a substantially higher number in inventory for FY 22. If no, please explain why not.

Response:

Year-end meter inventory levels for FY 2017 through FY 2020 satisfied the Company's criteria for meter change requirements. Per the Company's amended response to PUC 3-22, the Company proposes a reduced inventory for FY 2022 compared to previous years.

PUC 6-23

Request:

Refer to PUC 3-6, page 2 and the "Comments" relating to Purchased Meters, and the statement, "The Company notes that it has already reduced this budget from prior years and does not believe further reductions would be prudent."

(a) Please confirm whether these were the Purchase Meter budgets from FY 2017 through FY 2021:

FY 2017: $2,264,000;
FY 2018: $2,367,000;
FY 2019: $1,144,000;
FY 2020: $3,400,000;
FY 2021: $4,852,000.

(b) Please explain why the Purchase Meter budgets for FY 2017 through FY 2019 were much lower than the Purchase Meter budgets for FY 2020 and FY 2021.

Response:

(a) The Purchase Meter budgets referenced above for FY 2017, FY 2018, FY2020, and FY2021 are correct. The purchase meter budget for FY 2019 was $4,371,000.

(b) The Purchase Meter budget for FY 2017 and FY 2018 were lower than the budgets for FY 2019, FY 2020 and FY 2021 because the operations forecasted meter change units were less in these years, as noted in the Company's response to PUC 3-21. The meter purchase budgets align with the operations workplans for anticipated meter changes.

Prepared by or under the supervision of: Saadat Khan

PUC 6-24

Request:

Is there a difference in how financial accounting for the Company records expenses for meters purchased for use or inventory in gas distribution, compared to how the Company records expenses for meters purchased for use or inventory in electric distribution? Is the accounting different for meters that were placed into service during the fiscal year, compared to meters remaining in inventory at the end of the fiscal year? Please explain how the relevant expenses are recorded for the fiscal year financial reports.

Response:

There is no difference in how financial accounting for the Company records expenses for meters purchased for use or inventory in gas distribution, compared to how the Company records expenses for meters purchased for use or inventory in electric distribution.

The Company follows FERC Accounting rules for gas distribution and electric distribution meters where the cost of meters is capitalized in the respective plant meter accounts 381 and 370 whether actually in service or held in reserve. See Code of Federal Regulations Title 18, Chapter 1, Subchapter F Part 201 Gas Plant Account 381 Meters and Code of Federal Regulations Title 18, Chapter 1 Subchapter C, Part 1010 Electric Plant Account 370 Meters.

Meters are purchased and capitalized on blanket work orders and their vintage year is based on the year purchased and placed into storeroom stock. A separate blanket work order is created to capitalize asset installation costs. Thus, installation costs are recorded separately from the purchase asset cost.

Prepared by or under the supervision of: Andrey Androshchuk

PUC 6-25

Request:

Is there a difference in how the Company calculates the revenue requirement in the Gas ISR for meters purchased for use or inventory in gas distribution for the applicable ISR fiscal year, compared to how the Company calculates the revenue requirement for meters purchased for use or inventory in the Electric ISR for the applicable ISR fiscal year? Please explain how the revenue requirement is calculated for both.

Response:

Consistent with the Code of Federal Regulations, Gas and Electric meters are capitalized when purchased. As stated in the Company's response to Data Request PUC 6-19 subpart (c), all costs associated with bringing a meter to ready for installation stage are recorded as plant in service when purchased. The meter costs spent would be the same as meter costs in service in a fiscal year. Therefore, the revenue requirement in the Gas ISR for meters purchased for use or inventory in gas distribution for the applicable ISR fiscal year would be calculated based on Gas meters placed into service, just as the revenue requirement for meters purchased for use or inventory in the Electric ISR for the applicable ISR fiscal year would also be based on Electric meters placed into service

Prepared by or under the supervision of: Melissa Little