Docket No. 4770
Twenty-Fourth Set of Data Requests of the
Division of Public Utilities and Carriers to National Grid
February 16, 2018

Power Sector Transformation

24-1. Referring to the responses to DIV 8-58 and DIV 8-59, DIV 8-59 states, in part: "Therefore, a mechanism outside of base distribution rates must be established to enable proposed PST initiatives. Examples exist whereby commissions in National Grid's other jurisdictions have structured various mechanisms to accomplish cost recovery;" and DIV 8-58 states, in part: "[I]t is not feasible, practical, or desirable to try to structure cost recovery so as to flow through base distribution rates or another established mechanism."

a. The Company uses the definitive phrase "must be established" and refers to recovery occurring through base rates as "not feasible." Is this stated for emphasis because it is important, preferable, and/or desirable to the Company, or does the Company believe that it actually is impossible as a practical matter to advance the PST initiatives unless costs are recovered outside of base distribution rates? If impossible as a practical matter, please explain why it is impossible and identify any legal, practical, or other firm obstacles that make it impossible to advance the PST initiatives with costs being recovered through base distribution rates. Please explain.

b. Please describe all of the "examples" that the Company has identified where commissions in National Grid's other jurisdictions have structured other mechanisms to accomplish cost recovery for transformative initiatives.

Response can be found on Bates page(s) 1-2.

24-2. Referring to the response to DIV 10-1(b), the Company states, in part: "[U]nder the annual PST reconciliation filing, the burden will be on the Company to support the prudency and the appropriateness of any actual excess capital investment costs or O&M expense that exceeded the initial forecasts, including appropriate assignment of costs."

a. The Company's response appears to confine the Commission's prudency review to only those instances where costs <u>exceeded</u> the original forecasts. Is this a correct interpretation of the Company's response? If so, why should the Commission approve a mechanism that foregoes any and all prudency reviews, except for spending in excess of forecasts?

b. Would the Commission have the authority to consider the prudency of an expenditure that was within the original forecast, but could have easily been avoided given new information readily available at the time of incurring the expense, including without limitation obvious cost avoidance or cost reduction measures that could have been taken during implementation, but were not taken because of poor management decisions? If not, why not?

Response can be found on Bates page(s) 3.

New York Gas Enablement Settlement

24-3. Referring to the response to DIV 16-26 and PUC 5-17, please provide a schedule showing the monthly costs charged to and incurred by each gas distribution company in each of the National Grid jurisdictions for Gas Business Enablement from the inception of the program in mid-2016 through calendar year 2017 and indicate the months in which the costs were charged or incurred in each instance.

Response can be found on Bates page(s) 4-7.

24-4. Referring to the response to DIV 16-26 and PUC 5-17, please explain the New York ratemaking practice referred to in the response which affected Niagara Mohawk's decision not to seek recovery of non-recurring implementation expenses that may have been incurred during the historical test year and the period between the historical test year and the rate year in New York.

Response can be found on Bates page(s) 8.

24-5. Referring to the response to DIV 16-26 and PUC 5-17, please explain the parameters of the settlement in New York relating to the recovery of Gas Business Enablement costs, including an explanation of how the costs will be treated, the rate allowance in each year, the rate or accounting treatment (if any) of any costs that may be incurred in excess of the annual rate allowance, and the rate or accounting treatment (if any) that would occur if Niagara Mohawk underspends the annual rate allowance for Gas Business Enablement.

Response can be found on Bates page(s) 9-12.

24-6. Referring to the response to DIV 16-25, please provide an estimate of the impact on Service Company Rents for the Rate Year if, hypothetically speaking, the Commission in this docket granted an ROE of 9.1% instead of the requested 10.1%. (CLARIFYING NOTE: This question is essentially seeking an estimate of the approximate annual value of 100 basis points in the ROE, as it relates to the return on Service Company investments that are charged to Narragansett Electric's electric and gas businesses through Service Company Rents).

Response can be found on Bates page(s) 13.

Feeder Monitoring Proposal

24-7. Referring to the response to DIV 19-3 and the statement regarding early implementation of the feeder monitoring proposal: "The only practical impediment to starting earlier is that the Company does not expect to have approval for funding of the program until Fiscal Year 2020." Does the "funding" relate to an internal budgeting issue at the Company or does "funding" relate to obtaining an order from the Commission approving the project? In either event, please also explain why the Company does not expect to have approval for funding of the program until Fiscal Year 2020.

Response can be found on Bates page(s) 14.

24-8. Referring to the responses to DIV 19-2, please provide an estimate of the annual operating and maintenance (O&M) costs associated with the data and communications elements of the investment in feeder monitoring. If the O&M costs are different than the annual estimate of $10,000 indicated on the chart on Bates page 47 of PST-1, please explain why there is a difference and why the amounts were not quantified in the original PST filing.

Response can be found on Bates page(s) 15.

24-9. Referring to the responses to DIV 19-2,

a. Is there any reason why the feeder monitoring project could not commence during the Rate Year with the annual revenue requirement associated with both O&M expenses and capital investment included in base rates that are established in Docket 4770? If there are actual impediments (as opposed to Company preferences), please explain.

b. Please provide an estimate of the annual revenue requirement in Rate Years 1, 2, and 3, assuming the feeder monitoring program commenced in Rate Year 1 and continued in years 2 and 3.

Response can be found on Bates page(s) 16.

System Data Portal

24-10. Referring to Chapter 3 of Power Sector Transformation Book PST-1, Bates pages 44-46,

a. Is there any reason why the System Data Portal project could not commence (beyond the limited activities planned in the SRP 2018) during the Rate Year with the incremental annual revenue requirement associated with both O&M expenses and any capital investment included in base rates that are established in Docket 4770? If there are actual impediments (as opposed to Company preferences), please explain.

b. Please provide an estimate of the annual incremental revenue requirement in Rate Years 1, 2, and 3, assuming the System Data Portal commenced in Rate Year 1 and continued in years 2 and 3.

Response can be found on Bates page(s) 17.

<u>Grid Modernization Activities of the Company and Affiliates</u>

24-11. Has National Grid already undertaken or completed initiatives or projects over the last five years to modernize the distribution system in Rhode Island? If so, please identify and describe any significant initiatives or projects undertaken by the Company over that period. If not, please explain why National Grid has not undertaken any initiatives or projects to modernize the distribution system over the last five years.

Response can be found on Bates page(s) 18-19.

24-12. Has any of National Grid's electric distribution affiliates in Massachusetts and New York undertaken or completed any significant initiatives or projects over the last five years to modernize the distribution system (other than the Worcester pilot and Clifton Park demonstration projects)? If so, please identify and describe the initiatives or projects undertaken over that period.

Response can be found on Bates page(s) 20-23.

Division 24-1

Request:

Referring to the responses to DIV 8-58 and DIV 8-59, DIV 8-59 states, in part: "Therefore, a mechanism outside of base distribution rates must be established to enable proposed PST initiatives. Examples exist whereby commissions in National Grid's other jurisdictions have structured various mechanisms to accomplish cost recovery;" and DIV 8-58 states, in part: "[I]t is not feasible, practical, or desirable to try to structure cost recovery so as to flow through base distribution rates or another established mechanism."

a. The Company uses the definitive phrase "must be established" and refers to recovery occurring through base rates as "not feasible." Is this stated for emphasis because it is important, preferable, and/or desirable to the Company, or does the Company believe that it actually is impossible as a practical matter to advance the PST initiatives unless costs are recovered outside of base distribution rates? If impossible as a practical matter, please explain why it is impossible and identify any legal, practical, or other firm obstacles that make it impossible to advance the PST initiatives with costs being recovered through base distribution rates. Please explain.

b. Please describe all of the "examples" that the Company has identified where commissions in National Grid's other jurisdictions have structured other mechanisms to accomplish cost recovery for transformative initiatives.

Response:

a. The Company provided emphasis because a reconciling mechanism will allow for the type of funding mechanism whereby the Company is assured recovery of reasonable and prudently incurred costs associated with the types of new activities outlined in the Power Sector Transformation (PST) Plan initiatives, which initially present a level of risk and uncertainty that is not present in the more routine activities traditionally recovered through base distribution rates. As stated in the Company's response to Division 8-58, annual recovery through a reconciling mechanism provides the Company with the resources necessary to move forward with its investment in initiatives designed to serve the various objectives underlying the approved PST activities, and will assure that customers pay no more and no less than the reasonable and prudently incurred costs necessary to implement the PST initiatives. Accordingly, this will allow the Company to more expeditiously ramp up its PST investment than cost recovery through base distribution rates, and align this investment effort with Rhode Island PST policies. In fact, in Massachusetts, the Department of Public Utilities recently found that, because grid modernization will evolve substantially over the next five years, cost recovery for these investments is more appropriate outside of base rates. See NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05, at

442 (November 30, 2017) (discussing cost recovery through a grid modernization cost recovery reconciling factor). Although it would not be impossible, per se, to advance PST initiatives with costs recovered through base distribution rates, such approach would necessitate a reevaluation of the types of activities underlying the PST initiatives that the Company could realistically advance, taking into account the need for stakeholder input, flexibility, and transparency, as discussed in the Company's responses to Division 8-58 and Division 8-59.

b. With the current transformative initiatives, the Earnings Adjustment Mechanism contained in the settlement agreement submitted in Niagara Mohawk Power Corporation's general rate case, which is currently pending before the New York Public Service Commission, proposes the recovery of costs through a surcharge. Across all of National Grid's jurisdictions, many transformative initiatives in the past have been recovered through separate factors as a component of reconciling mechanisms and continue to be. For example, both energy efficiency costs and generation stranded costs are recovered though a separate mechanism. In addition, separate surcharges have been used to phase-in FAS 106 transition costs when FAS 106 was first introduced.

Prepared by or under the supervision of: Kayte O'Neill

Division 24-2

Request:

Referring to the response to DIV 10-1(b), the Company states, in part: "[U]nder the annual PST reconciliation filing, the burden will be on the Company to support the prudency and the appropriateness of any actual excess capital investment costs or O&M expense that exceeded the initial forecasts, including appropriate assignment of costs."

a. The Company's response appears to confine the Commission's prudency review to only those instances where costs exceeded the original forecasts. Is this a correct interpretation of the Company's response? If so, why should the Commission approve a mechanism that foregoes any and all prudency reviews, except for spending in excess of forecasts?

b. Would the Commission have the authority to consider the prudency of an expenditure that was within the original forecast, but could have easily been avoided given new information readily available at the time of incurring the expense, including without limitation obvious cost avoidance or cost reduction measures that could have been taken during implementation, but were not taken because of poor management decisions? If not, why not?

Response:

a. The Public Utilities Commission is not confined to just the exceeding amount; it can review all costs for prudency, regardless of whether the Company is below or above the original forecasts.

b. Please see the response to part a. above.

Prepared by or under the supervision of: Kayte O'Neill

Division 24-3

Request:

Referring to the response to DIV 16-26 and PUC 5-17, please provide a schedule showing the monthly costs charged to and incurred by each gas distribution company in each of the National Grid jurisdictions for Gas Business Enablement from the inception of the program in mid-2016 through calendar year 2017 and indicate the months in which the costs were charged or incurred in each instance.

Response:

Please refer to Attachment DIV 24-3, which shows the total Gas Business Enablement monthly costs incurred between April 2016 and December 2017 for all companies. Total incurred spend is $71.7 million, which is comprised of operating and maintenance expenses of $39 million and capital expenditure of $33 million. The first column identifies the company and the second column identifies the business segment. For completeness, Attachment DIV 24-3 reflects incurred spend for all companies not just gas companies. The bottom section of the attachment shows a summary by receiving company.

As shown in Attachment DIV 24-3, capital expenditure is incurred by National Grid USA Service Company, Inc. and will be charged as rent expense through the revenue requirements model as part of the cost of service. These charges will commence following the first Gas Business Enablement implementation. This is currently projected to occur in Spring 2018.

Prepared by or under the supervision of: Anthony Johnston and Christopher Connolly

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1																		The Narragansett Electric Company
2																		d/b/a National Grid
3																		RIPUC Docket No. 4770
4																		Attachment DIV 24-3
5																		Page 1 of 3
6																		
7			**Fiscal Year / P**	**Values**														
8			**001/2017**		**002/2017**		**003/2017**		**004/2017**		**005/2017**		**006/2017**		**007/2017**		**008/2017**	
9	**Receiving Company - Text**	**Segment**	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**	**Capex**
10	**Boston Gas Company**	MAGASD											198,710		286,577		580,310	
11	**Brooklyn Union Gas-KEDNY**	NYGASD											256,813		370,372		749,993	
12	**Colonial Gas Company**	MAGASD											44,452		64,108		129,816	
13	**KeySpan Corporation**	PARENT																
14	**KS Gas East Corp-KEDLI**	NYGASD											183,865		265,167		536,955	
15	**Massachusetts Electric Co**	FRTRAN																
16	**Massachusetts Electric Co**	MAELEC																
17	**Nantucket Electric Co**	MAELEC																
18	**Narragansett Electric Co**	FRTRAN																
19	**Narragansett Electric Co**	RIELEC																
20	**Narragansett Electric Co**	RIGASD											63,222		91,178		184,633	
21	**National Grid USA Parent**	PARENT	18,640		237,795		61,729		102,700		260,401		915,819		473,541		(270,628)	
22	**NE Electric Trans Corp**	FRELEC																
23	**NE Hydro-Trans Corp**	FRELEC																
24	**NE Hydro-Trans Elec Co**	FRELEC																
25	**New England Power Company**	FRTRAN																
26	**NG Development Holdings**	NONREG																
27	**NG Generation LLC**	FRPGEN																
28	**NG Glenwood Energy Center**	FRPGEN																
29	**NG LNG LP RegulatedEntity**	FRGASO																
30	**NG PortJeff Energy Center**	FRPGEN																
31	**NG Services, Inc.**	NONREG																
32	**NGUSA Service Company**	SERVCO																
33	**Niagara Mohawk Power Corp**	NYELEC																
34	**Niagara Mohawk Power Corp**	NYGASD											106,138		153,071		309,964	
35	**Niagara Mohawk Power Corp**	NYTRAN																
36	**Transgas Inc**	NONREG																
37	**Grand Total**		**18,640**		**237,795**		**61,729**		**102,700**		**260,401**		**1,769,019**		**1,704,013**		**2,221,042**	
38																		
39	**Receiving Company Summary**																	
40																		
41	**Gas Companies**		-	-	-	-	-	-	-	-	-	-	853,200	-	1,230,472	-	2,491,670	-
42	**Electric & Transmission Companies**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	**NGUSA Service Company**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	**Parent**		18,640	-	237,795	-	61,729	-	102,700	-	260,401	-	915,819	-	473,541	-	(270,628)	-
45	**Non Regulated**		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	**Total**		**18,640**	**-**	**237,795**	**-**	**61,729**	**-**	**102,700**	**-**	**260,401**	**-**	**1,769,019**	**-**	**1,704,013**	**-**	**2,221,042**	**-**

	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG
8		009/2017		010/2017		011/2017		012/2017		001/2018		002/2018		003/2018	
9	**Receiving Company - Text**	Opex	Capex	Opex	Capex	Opex	Capex	Opex	Capex	Opex	Capex	Opex	Capex	Opex	Capex
10	**Boston Gas Company**	550,161		444,483		1,536,903		1,073,264		345,816		628,118		700,093	
11	**Brooklyn Union Gas-KEDNY**	711,028		574,451		1,986,294		1,387,086		469,129		852,097		949,736	
12	**Colonial Gas Company**	123,072		99,432		343,807		240,090		77,764		141,245		157,430	
13	**KeySpan Corporation**														
14	**KS Gas East Corp-KEDLI**	509,058		411,276		1,422,081		993,080		316,599		575,049		640,943	
15	**Massachusetts Electric Co**														
16	**Massachusetts Electric Co**														
17	**Nantucket Electric Co**														
18	**Narragansett Electric Co**														
19	**Narragansett Electric Co**														
20	**Narragansett Electric Co**	175,040		141,417		488,985		341,471		109,079		198,124		220,826	
21	**National Grid USA Parent**	9,319		50,969		(1,789,339)		18,087		8,230		20,633		162,011	
22	**NE Electric Trans Corp**														
23	**NE Hydro-Trans Corp**														
24	**NE Hydro-Trans Elec Co**														
25	**New England Power Company**														
26	**NG Development Holdings**														
27	**NG Generation LLC**														
28	**NG Glenwood Energy Center**														
29	**NG LNG LP RegulatedEntity**														
30	**NG PortJeff Energy Center**														
31	**NG Services, Inc.**														
32	**NGUSA Service Company**														
33	**Niagara Mohawk Power Corp**														
34	**Niagara Mohawk Power Corp**	293,860		237,414		820,913		573,268		179,950		326,850		364,303	
35	**Niagara Mohawk Power Corp**														
36	**Transgas Inc**														
37	**Grand Total**	**2,371,538**		**1,959,443**		**4,809,643**		**4,626,345**		**1,506,567**		**2,742,116**		**3,195,342**	
38															
39	**Receiving Company Summary**														
40															
41	**Gas Companies**	2,362,219	-	1,908,474	-	6,598,982	-	4,608,259	-	1,498,338	-	2,721,484	-	3,033,330	-
42	**Electric & Transmission Companies**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	**NGUSA Service Company**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	**Parent**	9,319	-	50,969	-	(1,789,339)	-	18,087	-	8,230	-	20,633	-	162,011	-
45	**Non Regulated**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	**Total**	**2,371,538**	**-**	**1,959,443**	**-**	**4,809,643**	**-**	**4,626,345**	**-**	**1,506,567**	**-**	**2,742,116**	**-**	**3,195,342**	**-**

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4770
Attachment DIV 24-3
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	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU	AV	AW
8		004/2018		005/2018		006/2018		007/2018		008/2018		009/2018		Total Opex	Total Capex	Total
9	**Receiving Company - Text**	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**	**Capex**			
10	**Boston Gas Company**	1,259,887		(98,898)		302,206		309,462		(433,248)		314,978		7,998,822		
11	**Brooklyn Union Gas-KEDNY**	1,709,145		(134,164)		409,968		419,812		(146,662)		689,853		11,254,951		
12	**Colonial Gas Company**	283,311		(22,240)		67,957		69,589		(33,804)		108,903		1,894,929		
13	**KeySpan Corporation**									354		0		354		
14	**KS Gas East Corp-KEDLI**	1,153,441		(90,543)		276,673		283,316		(457,212)		246,769		7,266,516		
15	**Massachusetts Electric Co**									6,022		3		6,025		
16	**Massachusetts Electric Co**									901,832		67,708		969,540		
17	**Nantucket Electric Co**									11,553		700		12,253		
18	**Narragansett Electric Co**									62,698		31		62,729		
19	**Narragansett Electric Co**									306,420		25,507		331,928		
20	**Narragansett Electric Co**	397,399		(31,195)		95,323		97,612		(71,057)		138,783		2,640,840		
21	**National Grid USA Parent**	(66,069)		4,276		14,770		(48,704)		71,861		25,170		281,208		
22	**NE Electric Trans Corp**									354		0		354		
23	**NE Hydro-Trans Corp**									3,896		2		3,898		
24	**NE Hydro-Trans Elec Co**									6,022		3		6,025		
25	**New England Power Company**									177,113		88		177,201		
26	**NG Development Holdings**									6,376		3		6,379		
27	**NG Generation LLC**									143,107		71		143,178		
28	**NG Glenwood Energy Center**									4,605		2		4,607		
29	**NG LNG LP RegulatedEntity**									6,022		3		6,025		
30	**NG PortJeff Energy Center**									5,313		3		5,316		
31	**NG Services, Inc.**									5,668		3		5,670		
32	**NGUSA Service Company**				6,185,459		7,185,687		9,677,187		4,688,524		5,034,644		32,771,501	
33	**Niagara Mohawk Power Corp**									800,483		85,450		885,932		
34	**Niagara Mohawk Power Corp**	655,600		(51,463)		157,257		161,033		119,832		370,511		4,778,503		
35	**Niagara Mohawk Power Corp**									198,012		98		198,110		
36	**Transgas Inc**									2,834		1		2,835		
37	**Grand Total**	**5,392,714**		**(424,227)**	**6,185,459**	**1,324,154**	**7,185,687**	**1,292,120**	**9,677,187**	**1,698,395**	**4,688,524**	**2,074,643**	**5,034,644**	**38,944,132**	**32,771,501**	**71,715,632**
38																
39	**Receiving Company Summary**															
40																
41	**Gas Companies**	5,458,783	-	(428,502)	-	1,309,385	-	1,340,824	-	(1,022,151)	-	1,869,798	-	35,834,562	-	**35,834,562**
42	**Electric & Transmission Companies**	-	-	-	-	-	-	-	-	2,633,453	-	179,668	-	2,813,122	-	**2,813,122**
43	**NGUSA Service Company**	-	-	-	6,185,459	-	7,185,687	-	9,677,187	-	4,688,524	-	5,034,644	-	32,771,501	**32,771,501**
44	**Parent**	(66,069)	-	4,276	-	14,770	-	(48,704)	-	72,215	-	25,170	-	281,563	-	**281,563**
45	**Non Regulated**	-	-	-	-	-	-	-	-	14,878	-	7	-	14,885	-	**14,885**
46	**Total**	**5,392,714**	**-**	**(424,227)**	**6,185,459**	**1,324,154**	**7,185,687**	**1,292,120**	**9,677,187**	**1,698,395**	**4,688,524**	**2,074,643**	**5,034,644**	**38,944,132**	**32,771,501**	**71,715,632**

Division 24-4

Request:

Referring to the response to DIV 16-26 and PUC 5-17, please explain the New York ratemaking practice referred to in the response which affected Niagara Mohawk's decision not to seek recovery of non-recurring implementation expenses that may have been incurred during the historical test year and the period between the historical test year and the rate year in New York.

Response:

Consistent with the New York Public Service Commission's Policy on Test Periods in Major Rate Proceedings (dated November 23, 1977) (hereinafter, Policy Statement), New York ratemaking practice requires the presentation of a Historic Test Year with normalizing adjustments, for a twelve-month period expiring at the end of a calendar quarter no earlier than 150 days before the date of the filing, and a twelve-month forecast Rate Year, with a link between the two periods. Therefore, Niagara Mohawk Power Corporation (Niagara Mohawk) made normalizing adjustments to remove certain non-recurring implementation expenses during the Historic Test Year.

Revisions to forecast Rate Year costs may be made on the basis of data not available at the time of the original filing, and considering whether the impact is material. The Policy Statement provides that utilities may present actual results between the Historic Test Year and Rate Year but the information should be employed only to "test and verify the information principally relied upon and not itself as a 'test period.'"

Prepared by or under the supervision of: Anthony Johnston and Christopher Connolly

Division 24-5

Request:

Referring to the response to DIV 16-26 and PUC 5-17, please explain the parameters of the settlement in New York relating to the recovery of Gas Business Enablement costs, including an explanation of how the costs will be treated, the rate allowance in each year, the rate or accounting treatment (if any) of any costs that may be incurred in excess of the annual rate allowance, and the rate or accounting treatment (if any) that would occur if Niagara Mohawk underspends the annual rate allowance for Gas Business Enablement.

Response:

Niagara Mohawk Power Corporation's (Niagara Mohawk) Joint Proposal contemplates that Niagara Mohawk will continue to implement the Gas Business Enablement Program based on total National Grid USA Service Company, Inc. (Service Company) costs of $458.1 million through Fiscal Year (FY) 2023, comprising capital expenses and project operating expenses relating to the capital investment.

The rate allowance reflected in the Joint Proposal for the Gas Business Enablement Program for each of the three Rate Years (RY) of Niagara Mohawk's rate plan is provided below:

Costs to Niagara Mohawk	RY1 (FY19)	RY2 (FY20)	RY3 (FY21)
Rent Expense	$1.413M	$3.571M	$5.811M
O&M	$8.846M	$5.530M	$2.316M
Run the Business Costs	$1.200M	$2.412M	$2.941M

For purposes of determining Niagara Mohawk's allocable share of Gas Business Enablement Program costs, the total Service Company costs, comprised of capital and project operating expenses related to capital expenses, for the Gas Business Enablement Program will be capped at $458.1 million through FY 2023. In future rate proceedings, Niagara Mohawk may seek recovery of costs in excess of this cap that are associated with incremental investments in the Gas Business Enablement Program beyond those described in Attachment DIV 24-5 as long as the incremental costs are justified by measurable benefits.

A downward-only Service Company Rents Net Utility Plant and Depreciation Expense Reconciliation Mechanism is applicable to Information Services (IS) and Gas Business Enablement Program capital investments under the Joint Proposal. Each Rate Year, Niagara Mohawk will reconcile its respective actual IS and Gas Business Enablement Program average net utility plant and depreciation expense revenue requirements to the forecast revenue requirements, as set forth below:

Niagara Mohawk Revenue Requirements	RY1 (FY19)	RY2 (FY20)	RY3 (FY21)
IS and Gas Business Enablement – Electric	\$34.42M	\$36.72M	\$38.63M
IS and Gas Business Enablement – Gas	\$7.87M	\$10.06M	\$12.53M

The IS and Gas Business Enablement Program average net utility plant and depreciation expense revenue requirement will be calculated by applying Niagara Mohawk's pre-tax weighted average cost of capital in the respective Rate Years (8.07 percent in Rate Year One, 8.02 percent in Rate Year Two, and 7.99 percent in Rate Year Three) to the IS and Gas Business Enablement Program average net utility plant balance and adding the depreciation expense to the product.

The difference between the actual IS and Gas Business Enablement Program average net utility plant and depreciation expense revenue requirement and the target average net utility plant and depreciation expense revenue requirement will carry forward for each Rate Year and be summed at the end of Rate Year Three for electric and gas, respectively. If, at the end of Rate Year Three, the cumulative actual IS and Gas Business Enablement Program average net utility plant and depreciation expense revenue requirement is negative, Niagara Mohawk will defer the revenue requirement impact for the benefit of Niagara Mohawk customers. If, at the end of Rate Year Three, the cumulative actual IS and Gas Business Enablement Program average net utility plant and depreciation expense revenue requirement is positive, there will be no deferral.

The reconciliation mechanism will apply to Niagara Mohawk's aggregate total IS and Gas Business Enablement Program average net plant and depreciation expense combined, and not to individual components. The net plant target balances and reconciliation will not consider the impact of Accumulated Deferred Income Taxes (ADIT).

Prepared by or under the supervision of: Anthony Johnston and Christopher Connolly

GBE Program Scope

High-Level GBE Program Scope by Workstream

Asset Management –an enterprise asset management platform that will provide a single view of all assets and system of record

- Implement an enterprise-wide Geographic Information System ("GIS"), investment planning, integrity management, and design systems /tools integrated with the work management system
- Develop enterprise-wide investment planning / risk management capabilities

Work Management – a work management system with an integrated field mobile application allowing a single view of all work with the ability to prioritize work

- Implement an enterprise-wide work management system, including scheduling and mobility platforms with ability to optimize routes
- Develop planning and prioritization capabilities to ensure commitments are met, mandated work is completed and capital work is delivered
- Deploy enterprise-wide standardized processes and roles

Customer Engagement - enable easier customer interactions through greater visibility to planned activities and scheduling of upcoming work

- Implement an interaction platform with multi-channel, customer self-service options
- Provide access to real-time customer information and history

Regulatory & Compliance

- Incorporate pipeline safety and compliance standards into all elements of the design
- Develop robust technical training capability
- Simplify and align policies, procedures, work methods and training
- Incorporate elements of API 1173 – Pipeline Safety Management System (process safety)

Detailed Backbone Capabilities

- Enterprise Asset Management platform integration with SAP
- Enterprise Work Management system integrated with a field mobile application and back office systems (*i.e.,* Powerplan and SAP)
- Scheduling and dispatch
  - Optimized routing
  - Spatial crew visibility
- Field mobility solutions
  - electronic data capture
  - visibility to customer payment history
  - acceptance of credit card payments
  - print capability

- electronic work packages
- field access to maps
- field asset correction and geolocation

- GIS Consolidation, GIS Data Remediation, Landbase Conflation
- Enterprise GIS/Enterprise Asset Management Platform Integration
- Data management, archiving, record-keeping
- Customer collections status visibility
- Standardized compatible unit library
- Customer appointment booking
- Contractor mobility solution
- Mobile time entry and tracking
- Material traceability
- Work forecasting and planning solution
- Asset investment planning and management tool
- Integrity management application
- Mobility tool for customer meter services work, inspection and maintenance work, preventative maintenance activities, construction work, leak inspection and leak repair
- Gas safety instructor-led, video-based, and mobile technical training

Detailed Enhanced Capabilities

- Asset investment scenario planning
- Graphical Work Design and CU estimating
- Customer contact center front end application integrated with customer information systems and field mobility solution providing 360° view of the customer
- Field crew customer interaction portal
- Customer self-service portal
- Employee support interaction portal
- Projects and program management platform
- Complex design tools
- Auto work notifications
- Supervisor mobile platform
- Field mobile redlining and GIS mapping
- Project Management Platform integration with GIS, Enterprise Asset Management and asset accounting
- Spatial asset risk visibility
- Large commercial and landlord interaction portal

Division 24-6

Request:

Referring to the response to DIV 16-25, please provide an estimate of the impact on Service Company Rents for the Rate Year if, hypothetically speaking, the Commission in this docket granted an ROE of 9.1% instead of the requested 10.1%. (CLARIFYING NOTE: This question is essentially seeking an estimate of the approximate annual value of 100 basis points in the ROE, as it relates to the return on Service Company investments that are charged to Narragansett Electric's electric and gas businesses through Service Company Rents).

Response:

The estimated impact on Service Company IS Rents charged to Narragansett Electric and Narragansett Gas is shown below:

Narragansett Electric: ($190,574)

Narragansett Gas: ($64,323)

Prepared by or under the supervision of: Melissa Little

Division 24-7

Request:

Referring to the response to DIV 19-3 and the statement regarding early implementation of the feeder monitoring proposal: "The only practical impediment to starting earlier is that the Company does not expect to have approval for funding of the program until Fiscal Year 2020." Does the "funding" relate to an internal budgeting issue at the Company or does "funding" relate to obtaining an order from the Commission approving the project? In either event, please also explain why the Company does not expect to have approval for funding of the program until Fiscal Year 2020.

Response:

In this context, "funding" relates to obtaining an order from the Public Utilities Commission (PUC) approving the project. The Feeder Monitoring Sensors project is one element of the Company's holistic Power Sector Transformation (PST) plan that the Company has proposed in Docket No. 4780, and for which the Company has requested that the PUC make certain findings by October 1, 2018. Following the PUC's review, the Company has proposed to submit, as part of an annual plan process, a formal proposal and funding request by December 1, 2018 for approval by April 1, 2019 for spending in Fiscal Year 2020. Accordingly, the Company has not included the Feeder Monitoring Sensors project in any earlier internal budgets or work plans.

Prepared by or under the supervision of: Robert Sheridan

Division 24-8

Request:

Referring to the responses to DIV 19-2, please provide an estimate of the annual operating and maintenance (O&M) costs associated with the data and communications elements of the investment in feeder monitoring. If the O&M costs are different than the annual estimate of $10,000 indicated on the chart on Bates page 47 of PST-1, please explain why there is a difference and why the amounts were not quantified in the original PST filing.

Response:

The Company estimates the annual operating and maintenance (O&M) costs associated with the data and communications elements of the investment in the Feeder Monitoring Sensors project to be $200 per feeder per year. The Company assumes this cost is incurred the year after the installation of the feeder monitoring sensors. Therefore, the Company estimates an O&M cost of approximately $5,000 for 26 feeders in fiscal year (FY) 2021, $10,000 for 52 feeders in FY2022, and $16,000 for the 78 feeders with feeder monitoring sensors installed in FY2023. The FY2021 and FY2022 O&M costs are aligned with the chart on Bates Page 47 of PST Book 1; however, because the figures are presented in millions of dollars to two significant digits, both values are represented as $0.01 million.

In response to this request, the Company realized that it inadvertently omitted the FY2023 O&M costs in the chart on Bates Page 47 of PST Book 1. The table below corrects this omission and presents the costs in millions of dollars to three significant digits for clarity.

Updated Table 3-2: Cash Flow Estimate for Feeder Monitoring Sensors Project

Feeder Monitoring Sensors Cash Flow, $M	FY19	FY20	FY21	FY22	FY23
CAPEX	$ -	$ 0.455	$ 0.455	$ 0.455	$ 0.455
O&M	$ -	$ -	$ 0.005	$ 0.010	$ 0.016
Total	$ -	$ 0.455	$ 0.460	$ 0.465	$ 0.471

Prepared by or under the supervision of: Robert Sheridan

Division 24-9

Request:

Referring to the responses to DIV 19-2,

a. Is there any reason why the feeder monitoring project could not commence during the Rate Year with the annual revenue requirement associated with both O&M expenses and capital investment included in base rates that are established in Docket 4770? If there are actual impediments (as opposed to Company preferences), please explain.

b. Please provide an estimate of the annual revenue requirement in Rate Years 1, 2, and 3, assuming the feeder monitoring program commenced in Rate Year 1 and continued in years 2 and 3.

Response:

a. Chapter 3 of the Company's Power Sector Transformation (PST) Plan provides a holistic view of investments to enable a modern grid. Presenting these investments as a holistic suite provides clarity and transparency for stakeholders in Rhode Island on the overall investment roadmap and associated cost. Furthermore, the annual nature of the plan facilitates a level of flexibility and the ability to respond to advances in its Massachusetts and New York jurisdictions. The Feeder Monitoring Sensor project fits squarely within the PST Plan vision and holistic suite of modern grid investments.

   Although there is no technical impediment to implementing the Feeder Monitoring Sensors project in the Rate Year, the Company has proposed to align the PST annual plan process with the implementation of its capital work plan, which is done on a fiscal year (FY), and not a rate year basis. Please also see the Company's response to Division 5-11, , in which the Company discusses why it would not be appropriate to recover the costs of these investments in base distribution rates.

b. As noted in the response to part a. above, the rate years do not align with the Company's typical FY implementation of the capital investment plan. However, there would be no change to the revenue requirements filed by the Company even if it was assumed the Feeder Monitoring Sensors project commenced in Rate Year 1. The Company has assumed a half-year convention on all the capital revenue requirements in the year of investment. This means that regardless if Year 1 represents the 12 months ending March 31, or the 12 months ending August 31 (which represents the end of the Company's rate year), the revenue requirement would not change.

Prepared by or under the supervision of: Robert Sheridan

Division 24-10

Request:

Referring to Chapter 3 of Power Sector Transformation Book PST-1, Bates pages 44-46,

a. Is there any reason why the System Data Portal project could not commence (beyond the limited activities planned in the SRP 2018) during the Rate Year with the incremental annual revenue requirement associated with both O&M expenses and any capital investment included in base rates that are established in Docket 4770? If there are actual impediments (as opposed to Company preferences), please explain.

b. Please provide an estimate of the annual incremental revenue requirement in Rate Years 1, 2, and 3, assuming the System Data Portal commenced in Rate Year 1 and continued in years 2 and 3.

Response:

a. Technically, the System Data Portal could commence with additional activities beyond those planned in the System Reliability Procurement (SRP) 2018 Plan during the Rate Year with the incremental annual revenue requirement associated with both operating and maintenance (O&M) expenses and any capital investment included in base distribution rates that are established in Docket No. 4770. The Company, however, has proposed additional resources to implement the increased scope of work as part of its proposal for the System Data Portal project in the Power Sector Transformation (PST) Plan. If approved, this resource acquisition will take time to implement, thereby affecting the amount of work that could be completed in the Rate Year.

Please also see the Company's response to Division 24-9a.

b. There would be no change to the revenue requirements filed by the Company because the Company has assumed a half-year convention on all the capital revenue requirements in the year of investment. This means that, regardless if Year 1 represents the 12 months ending March 31, or the 12 months ending August 31 (which represents the end of the Company's rate year), the revenue requirement would not change.

Prepared by or under the supervision of: Robert Sheridan

Division 24-11

Request:

Has National Grid already undertaken or completed initiatives or projects over the last five years to modernize the distribution system in Rhode Island? If so, please identify and describe any significant initiatives or projects undertaken by the Company over that period. If not, please explain why National Grid has not undertaken any initiatives or projects to modernize the distribution system over the last five years.

Response:

Yes. Below is a list of significant projects that the Company has undertaken over the last five years to modernize the distribution system in Rhode Island. Please see Chapter 3 of the Power Sector Transformation Plan, On-Going Grid Modernization Activities, Bates Pages 42-43 of PST Book 1, for additional details regarding some of these projects. All of these projects are ongoing.

- Customer Distributed Energy Resource (DER) Programs:
  - Non-Wires Alternative (NWA) pilot project in Tiverton and Little Compton, Rhode Island was initiated to create one megawatt of peak load relief on two feeders serving the area to avoid the need for construction of a third feeder.
  - ConnectedSolutions is a direct load control (DLC) pilot for commercial and industrial (C&I) and residential customers, which uses Whisker Lab's demand response platform to help the Company control participating thermostats during times of electrical system peak.

- Volt-var Management: Volt-var optimization (VVO) projects have been completed through the Infrastructure, Safety, and Reliability (ISR) plan, which utilize distribution field devices to provide energy savings to customers and peak load reductions through active real-time voltage control. In addition to the overall improved coordination of field device operation, the local devices themselves included upgrades to their locally situated control boxes (see Automated Field Devices below). Finally, the Company also evaluated a privately owned mesh network in a limited area.

- Fault Analysis and Power Flow Analysis: Radial distribution analysis, networked sub-transmission and transmission analysis, fault current, and arc flash software packages are continually reviewed for the latest version and functionality required by National Grid.

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- Outage Management System (OMS) and Supervisory Control and Data Acquisition (SCADA): The Company upgraded its OMS to a new ABB Network Manager OMS since the New England system cutover occurred in December 2015. The Company also upgraded its Energy Management System (EMS)/SCADA to a new ABB Network Manager EMS/SCADA since the New England system cutover occurred in April 2015. These upgrades improved system performance and allowed the Company to continue the significant data collection necessary for the remote monitoring and distribution automation aspects of grid modernization.

- DER and Load Forecasting: The Company is developing new software tools and analytics to generate highly granular forecasts of the electrical system including various load, generation, and energy storage technologies. Forecasts in Rhode Island are currently based on top-down approaches and include load reductions due to projections for energy efficiency improvements. These forecasts have been recently updated to also include load reductions due to projections for photovoltaic-based distributed generation throughout the service territory.

- Automated Field Devices: Recloser communication program is nearing completion to replace cellular radios that have become obsolete. Additionally, recloser, capacitor, and regulator controller standards are now microprocessor-based, allowing future programmable functionality. For distribution capacitors, these upgrades allow for enhanced local operation, permitting for decisions based on local conditions, rather than standard time-of-day actuation. For new installations of both capacitors and regulators, the control boxes were upgraded to allow for remote connectivity, via a radio, to the Company SCADA system, as well as visibility at the control room of the operating status of these devices.

- Sensing and Measurement: Reclosers and regulators are designed with bi-directional sensing and control. The Company is initiating the programmatic installation of transmission ground fault detection system termed 3V0.

- Physical Grid Infrastructure: The Company continues to upgrade its infrastructure through asset condition evaluations. When assets are identified for proactive replacement, the equipment is also brought to the latest technological standards. Communication equipment, control equipment, relays, and sensors are the categories of devices that are subject to such an upgrade.

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Division 24-12

Request:

Has any of National Grid's electric distribution affiliates in Massachusetts and New York undertaken or completed any significant initiatives or projects over the last five years to modernize the distribution system (other than the Worcester pilot and Clifton Park demonstration projects)? If so, please identify and describe the initiatives or projects undertaken over that period.

Response:

Yes. In addition to the Worcester pilot and Clifton Park demonstration projects, below is a list of significant projects that National Grid's electric distribution affiliates in Massachusetts and New York have undertaken over the last five years to modernize the distribution system. Note that for this response, we use the term "National Grid" to refer to the Company and all of its affiliates.

All of these projects are ongoing with the exception of the Distribution Management System pilot, which was completed in 2017.

- Customer DER Programs in New York:
    - Direct Load Control (DLC) programs: CoolControl program in Kenmore, New York markets and deploys WiFi connected smart plugs, thermostats, and window air conditioning units that can be controlled by Think Eco's demand response platform at National Grid's request. The ConnectedSolutions program in upstate New York, Massachusetts, and Rhode Island uses Whisker Lab's demand response platform to help National Grid control participating thermostats during times of electrical system peak.
    - Distribution Load Relief Program (DLRP) in the Kenmore, New York designated area is a contingency demand response program targeting demand response aggregators and large commercial customers for load relief during distribution electrical emergencies when targeted equipment is expected to exceed its limits.
    - Commercial System Relief Program (CSRP) in upstate New York is a peak shaving program targeting demand response aggregators and large commercial customers to relieve the electrical system during summer load peaks when targeted area loads are forecasted to exceed 92 percent of National Grid's 95/5 peak load forecast.
    - Demonstration Projects: Potsdam Microgrid project in New York is evaluating the connection of local DERs and a redundant underground distribution system with key community loads. The project will develop an engineering design and an investment grade financial model and evaluate new microgrid utility services. The Fruitbelt project in Buffalo, New York

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deployed a community solar project with National Grid owned solar installed on residential customer rooftops in an area with a significant amount of low income residents. The project will assess the benefits managing arrears and the impact of distributed solar on the local distribution feeder when solar is installed on the roofs in this community.

  - National Grid's Non-Wires Alternatives (NWA) program in National Grid's New York service territory is the umbrella term for ensuring that a portfolio of alternatives to distribution and/or transmission lines is analyzed and considered in the planning and possible permitting of such facilities. A NWA could include any action or strategy that could help defer or eliminate the need to construct or upgrade components of a transmission and/or distribution system. Seven NWA requests for proposals have been released to the public to date and are being evaluated for their cost effectiveness.
  - National Grid's Distributed Generation Interconnection demonstration program will accelerate the pace and scale of interconnecting distributed generation systems above 50 kilowatts in National Grid's New York service territory. National Grid has completed all construction work in the demonstration areas and the National Grid's Customer Energy Integration department continues to market the program to developers seeking to interconnect in the demonstration areas.
- DER Provider Data/Information: National Grid's System Data Portal is a collection of data and interactive maps intended to help customers, contractors and developers facilitate the interconnection of DER and its utilization in support of the operation of the distribution system in National Grid's upstate New York electric service territory.
- Locational Value Analysis: National Grid is supporting the New York REV Value of DER (VDER) proceeding by performing a study to consider how it may develop more accurate valuation and compensation mechanisms for DERs that will more appropriately "reflect and properly reward DER's actual value to the electric system and that ensure all customers pay their fair share for the costs of grid operation and benefit from the value they provide". The initial phase of the study includes performing an enhanced Marginal Cost of Service (MCOS) study or Marginal Avoided Distribution Cost (MADC) that will consider locational values developed through a system-wide assessment. The results from this study will be used to provide time-phased marginal cost values at a location level that may be used for valuation of DER in identified high value areas. National Grid plans to file these cost values in summer 2018.
- Hosting Capacity: National Grid's Hosting Capacity Analysis provides useful information to help guide distributed generation interconnections in National Grid's New York service territory to the most suitable locations of the grid by providing an indication of the amount of solar generation that may be interconnected on an individual distribution feeder without the need for significant system upgrades to accommodate the interconnection.

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- DER Management:
  - Solar Phase I and II programs in Massachusetts are an opportunity for National Grid to own and operate solar facilities in order to improve its understanding of the potential impact of renewable proliferation, and how solar facilities may be used to help modernize the distribution system. To date, National Grid owns around 20 megawatts of solar, with several additional megawatts in construction. Additionally, National Grid is testing the operation and benefits of energy storage co-located with renewable energy generators in Massachusetts.
  - Buffalo Niagara Medical Center (BNMC) Distributed System Platform (DSP) demonstration project is developing a framework for a DSP, where local loads and generators can participate in distribution specific price signals.
  - East Pulaski and Kenmore demonstration energy storage projects include two 1.5 megawatt/ 3 megawatt-hour substation based energy storage systems. The Kenmore project is designed to assist in alleviating a supply constraint, potentially deferring sub-transmission investment. The East Pulaski project is designed to alleviate the possibility of the substation surpassing its rated capacity and impacting reliability.
- Distribution Management System (DMS):
  - A DMS pilot project was carried out in 2016 in National Grid's New York region to help understand the maturity, strengths, and weaknesses of DMS applications, and the challenges associated with integration of the applications, including the system data and personnel requirements necessary to support a larger scale implementation of a DMS. For example, the pilot looked to understand the granular data requirements for the increasing number of distributed energy resources and increasingly diverse loads.
  - National Grid's Energy Management/Remote Terminal Unit (EMS/RTU) initiative includes the addition of RTUs and related infrastructure at substations presently lacking remote monitoring and control capabilities. RTUs in substations communicate with the EMS and provide the means to leverage substation data that provides operational intelligence and significantly reduces response time to abnormal conditions through real time monitoring and control. National Grid has installed EMS/RTU at several stations across upstate New York over the past five years.
- DER and Load Forecasting: National Grid is developing new software tools and analytics to generate highly granular forecasts of the electrical system including various load, generation, and energy storage technologies. National Grid is beginning bottoms-up, long-term, hourly probabilistic forecasts for each distribution feeder in National Grid's New York service territory and can consider this approach for its other service territories in the future.
- Automated Field Devices: National Grid's Sub-Transmission Distribution Automation (DA) and Distribution Line Reclosers initiative is a reliability-focused

strategy designed to meet both state regulatory targets and support first quartile reliability performance. Line reclosers are needed to isolate permanent faults on the distribution system and minimize the scope of the interruption by protecting the feeder breaker. IntellitTeam Logic units have been installed on 34.5kV Sub-Transmission systems across upstate New York and primary line reclosers will be installed on 15 kV class distribution feeders.

- Sensing and Measurement: National Grid has evaluated a new type of primary metering sensor, commonly referred to as a "feeder monitor" that can be installed with a hot-stick (from the ground) and dramatically reduce the amount of installation effort required. Sensor measurements will yield near real-time as well as forensic data that will provide deeper insight into system performance. Further use of the data will permit studies that may drive design changes for network optimization. These sensors are currently being deployed in New York at a rate of about 50 per year. They are also included in National Grid's Massachusetts Grid Modernization plan, and National Grid's Rhode Island Power Sector Transformation Plan.
- Operational Communications: National Grid's Recloser Communication Upgrades initiative will replace the obsolete Sensus radios 2G cellular network with GE Orbit series radios utilizing the Verizon 4G cellular data network in National Grid's New York service territory. This initiative will also develop an internal wireless network that can support a variety of distribution devices and communications mediums allowing National Grid to gather much larger quantities of data at a reduced cost.
- Physical Grid Infrastructure:
    - National Grid is supporting a New York State Energy Research and Development (NYSERDA) New York Prize Microgrid project that seeks to develop community microgrids by several third party developers across New York. National Grid is currently supporting the design stage of these projects, with four projects within its service territory.
    - National Grid has investigated power quality conditioning of the secondary circuits using devices that attach after a pole mounted transformer and regulate the voltage and power quality that is delivered to the customers served by that transformer. National Grid has tested four locations in Massachusetts to evaluate the potential impact and performance of this technology.