Before the
Rhode Island Public Utilities Commission

Proceeding on the Narragansett Electric Company d/b/a National Grid Proposed Tariff Changes	)))	Docket No. 4770

Direct Testimony of
Tim Woolf and Melissa Whited

On Behalf of
The Division of Public Utilities and Carriers

April 6, 2018

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. **Mr. Woolf:** My name is Tim Woolf. I am the Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

A. **Ms. Whited:** My name is Melissa Whited. I am a Principal Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. **Mr. Woolf:** Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU) from 2007 through 2011. In that capacity, I was responsible for overseeing a substantial expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of the DPU energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; review and approval of smart grid pilot programs; and review and approval of long-term contracts for renewable power. I was also responsible for overseeing a variety of other dockets before the Commission, including several electric and gas utility rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director at the Association for the Conservation of Energy; a Staff Economist at the Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Masters in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University. My resume is attached as Exhibit TW/MW-1.

A. **Ms. Whited:** I have seven years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models, rate design, policies to address distributed energy resources (DER), and market power. I have testified before the Massachusetts Department of Public Utilities, the Hawaii Public Utilities Commission, the Public Service Commission of Utah, the Public Utility Commission of Texas, the Virginia State Corporation Commission, and the Federal Energy Regulatory Commission.

I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. Prior to rejoining Synapse, I published an article in the Journal of Regional Analysis and Policy regarding the economic impacts of water transfers, analyzed state water efficiency policies while at the Wisconsin Public Service Commission, and conducted econometric analyses of energy efficiency cost-effectiveness. My resume is attached as Exhibit TW/MW-2.

Q. On whose behalf are you testifying in this case?

A. We are testifying on behalf of the Division of Public Utilities and Carriers (the Division).

Q. Have you previously testified before the Rhode Island Public Utilities Commission?

A. **Mr. Woolf:** Yes. I have testified before the Rhode Island Public Utilities Commission (the Commission) on behalf of the Division in National Grid's (the Company's) Energy Efficiency and System Reliability Plans. I was an active member of the Docket 4600 Working Group, and I assisted the Division with the Rhode Island Power Sector Transformation report recently submitted to Governor Raimondo. I also recently testified before the Commission on behalf of the Division in Docket 4783 on National Grid's proposed advanced metering (AMF) pilot.

Ms. Whited: Yes. I recently testified before the Commission on behalf of the Division in Docket 4783 on National Grid's proposed AMF pilot.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to review and comment on several topics that are directly related to rate case issues in this docket and are contained in the joint pre-filed direct testimony of National Grid's Power Sector Transformation (PST) Panel (the Panel). We address the Company's proposed performance incentive mechanisms (PIMs), because these are integrally related to the authorized ROE that will be set in this rate case. We address the Company's benefit-cost analyses (BCA), because these are used to determine the PIM incentives that will affect the authorized ROE. We also address the Company's request for recovery of costs for the AMF study and for the distributed energy resources (DER) enablement investments, because recovery of these costs will affect the revenue requirements that are approved in this rate case.

Q. Is the Division sponsoring other witnesses that address issues related to your testimony?

A. Yes. The following Division witnesses address issues that are related to our testimony:

- Tim Woolf provides an overview of the Division's case in this docket. It introduces all of the Division's witnesses, presents the Division's overarching vision for power sector transformation, and addresses the role of multi-year rate plans in achieving that vision.
- Matt Kahal addresses cost of capital and return on equity (ROE) issues.
- Greg Booth addresses several elements of National Grid's Power Sector Transformation Plan that relate to this rate case, including advanced metering functionality and the grid modernization elements.
- Roger Colton addresses low-income issues, including those related to the A60 low-income discount rate.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions.

A. Our conclusions are summarized as follows:

- The amount of change and evolution in today's power sector requires a more integrated, long-term approach to utility planning and ratemaking, relative to historical practices. All National Grid's planning initiatives (energy efficiency, system reliability and procurement, conventional distribution projects, grid modernization, power sector transformation) should be planned for, reviewed by stakeholders, and treated by the Commission in a more holistic way.
- Performance incentive mechanisms should play an integral role in the overall ratemaking approach used to achieve power sector transformation goals. PIMs can align utility financial incentives with regulatory priorities and offset some of the existing incentives that emphasize capital investments and hinders utility investment in DERs.
- PIMs are directly related to a utility's authorized ROE, because they both provide shareholder revenues and incentivize utility management decisions. These two topics must be addressed by the Commission together in a rate case, to promote economic decision-making, achieve desired performance outcomes, and avoid over-recovery (or under-recovery) of revenues by the Company.
- The shareholder revenues provided by existing and proposed PIMs will be significant enough to warrant the Commission establishing National Grid's authorized ROE at the lower end of the reasonable cost of equity range. Such a shifting of revenue sources will mitigate the Company's incentive to increase rate base and focus management's attention on achieving power sector transformation goals.
- National Grid's proposed PIMs are a reasonable attempt to improve the Company's incentives, consistent with the PST Report. However, many of them suffer from some critical design flaws. In particular:
    - The baseline for the FCM and the Transmission PIMs are based on a historical year, which does not properly account for the natural variations in the relevant metric.

- The Company does not have a forecast for its transmission peaks, which makes it difficult to determine reasonable targets.
- Several of the Company's PIMs have metrics that are not directly related to the desired outcome or are not needed because they address activities that the Company should be doing anyway.

- The Company's "new grid modernization" (i.e.,"DER-enabling") investments should not be treated separately from conventional investments or PST-related investments, either in terms of planning, regulatory oversight, or cost recovery.
- AMF can play a critical, foundational role in transforming the RI power sector, and will be necessary to achieve the outcomes and goals articulated by the Docket 4600 Working Group and the Commission's Guidance Document, particularly the goal of implementing time-varying rates. National Grid's BCA indicates that AMF could be cost-effective under several likely scenarios.
- National Grid's proposal to study AMF is an important step toward implementing AMF and achieving power sector transformation goals. However, the Division concludes that this study should be done for less than the $2 million asked for by the Company and should include examination of shared communications and third-party ownership models.
- National Grid's BCAs have limited value for determining the magnitude of PIM incentives because they do not include some important benefits and they use outdated avoided costs.

Q. Please summarize your recommendations.

A. Our recommendations are summarized as follows:

- The Commission should address National Grid's proposed PIMs in this rate case docket, to ensure that decisions regarding the Company's authorized ROE fully account for the shareholder revenues and the financial incentive implications of the PIMs.

- The Commission should adopt the set of PIMs proposed by the Division, as described in detail in our testimony below. Table 1 provides a summary of the Division's proposed PIMs.

Table 1. Summary of the Division's Proposed PIMs

Type	PIM	Description
System Efficiency	Transmission Peak	Reduce transmission peaks relative to forecast
	FCM Peak	Reduce annual FCM peak relative to forecast
Distributed Energy Resources	Demand Response – Res.	Increase MW enrollment in cost-effective DR
	Demand Response - C&I	Increase MW enrollment in cost-effective DR
	Electric Heat Initiative	Increase MW of cost-effective electric heat
	Electric Vehicle Initiative	Reduce GHG emissions relative to baseline
	Behind-the-Meter Storage	Install MW of cost-effective storage
	Utility-Scale Storage	Install MW of cost-effective storage
	Non-Wires Alternatives	Procure cost-effective NWA from third-parties
PST Support	Low Income: Participation	Increase LI participation in DER initiatives
	Low Income: Enrollment	Increase customer enrollment in LI rate A60
	Customer Information	Provide key data to customers and third-parties
	Peak Demand Forecasting	Improve and expand current forecasting practices

- The Commission should establish National Grid's authorized ROE at the lower end of the cost of equity range to (a) account for the additional shareholder revenues from our proposed PIMs, and (b) mitigate the existing financial incentive to increase capital investments.
- The Commission should establish the regulatory procedures to be used to implement PIMs and allow the Company to recover the PIM incentives. This should include:
    - An annual Performance Incentive Mechanism Plan that presents all of the relevant metrics, targets, baselines, and incentives for the PIMs to be applied in the following calendar year.
    - An annual Performance Report that presents all of the historical data on the relevant metrics, targets, baselines, and incentives for the PIMs that were in place in the previous calendar year.

- An incentive recovery process that adjusts rates once per year to reflect the PIM incentives earned by the Company in the previous calendar year.

- The Commission should require the Company to file the first (i.e., 2019) PIM Plan by November 31, 2018. This plan should update all elements of the Company's PIMs based on the Commission findings and directives in this docket.
- The Commission should approve National Grid's request for funding of the AMF Study. However, the Commission should approve only $1 million of the requested funds.
- The Commission should require the Company to file grid modernization plans that comprehensively and consistently evaluate all distribution system opportunities over the long-term.
- The Commission should require the Company to treat "new grid modernization" investments comparably with its conventional distribution system investments.

3. THE ROLE OF PERFORMANCE INCENTIVE MECHANISMS

Q. The Commission has bifurcated the rate case docket (Docket 4770) from the power sector transformation docket (Docket 4780). Why is the Division sponsoring a witness to address performance incentive mechanisms in this rate case docket?

A. As described in the direct testimony of Mr. Woolf, PIMs should play an integral role in the overall ratemaking approach used to achieve power sector transformation goals. In conjunction with multi-year rate plans, PIMs can help align a utility's financial incentives with regulatory policy goals.

Performance incentive mechanisms and the authorized ROE serve similar and inter-related functions. They both provide revenues for the Company's shareholders, for the rate year and all the years until the next rate case. They also both provide utility management with financial incentives that can have a large impact on utility performance, utility rates, and services to customers. Because of this inter-relationship, it is critical for the Commission to consider the authorized ROE and the PIMs together. Otherwise, the ultimate impacts of these two mechanisms treated separately could lead to unintended consequences, uneconomic decision-making, undesirable performance outcomes, and over-recovery (or under-recovery) of revenues by the Company. These points are described in Section 4.2

For this reason, it is essential that the Commission consider PIMs in the context of Docket 4770. When determining the authorized ROE in Docket 4770, the Commission should recognize the significant amount of shareholder revenues that the Company could earn from PIM incentives. As we demonstrate in Section 4.2, potential shareholders revenues from existing and proposed PIMs could be 200 basis points or higher. This amount of shareholder revenues is too large to be ignored by the Commission as it makes important decisions regarding the Company's authorized ROE.

Q. What benefits do PIMs offer over traditional ratemaking practices?

A. PIMs offer many advantages relative to traditional cost-of-service ratemaking, including:[1]

- They help to make regulatory goals and incentives explicit.
- They allow regulators to offset or mitigate those current financial incentives that are not well aligned with the public interest.
- They allow regulators to improve utility performance in specific areas where historical performance has been unsatisfactory.

[1] These are taken from Synapse Energy Economics, *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, Prepared for the Western Interstate Energy Board, March 2015, page 1.

- Where utilities are subject to economic and regulatory cost-cutting pressures, they can encourage utilities to maintain, or even improve, customer service, customer satisfaction, and other relevant performance areas.
- They allow regulators to provide specific guidance on important state and regulatory policy goals.
- They allow regulators to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific costs and means to obtain those outcomes.
- They can help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.
- They can help support new regulatory models that provide utilities with greater incentives to achieve desired outcomes and that tie utilities' profits more to performance than to capital investments.
- They can be applied incrementally, providing a flexible, relatively low-risk regulatory option.

Q. Please provide brief definitions of the terms that are used in reference to PIMs.

A. It is important to distinguish between several different components of performance incentive mechanisms. In this testimony we will use the following terms:

- Performance area; refers to the type of performance or desired outcome that the PIM is trying to influence (e.g., FCM peak demand).
- Metric; refers to the type of data that is used to track and monitor the performance or desired outcome (e.g., actual FCM peak demand, relative to a baseline).
- Baseline; refers to the counterfactual case of what would have occurred in the absence of the PIM. (e.g., the forecasted 2019 FCM peak demand.)
- Target; refers to a specific goal that the utility is directed to achieve (e.g., 29 MW reduction in the FCM peak demand in 2019).

- Deadband; a deadband is a region around the target within which the Company would not earn a reward (e.g., 14.5 MW below the forecasted 2019 FCM peak demand). The concept of a deadband is often used to account for uncertainty regarding the target or to allow for some deviation from the target due to factors outside of utility control.
- Incentive; refers to the amount of money that the utility can be rewarded for performance relative to the target (e.g., five basis points for achieving the 2019 FCM peak demand reduction target). The financial incentive can be expressed in terms of basis points on the utility's return on equity, as we do in this testimony.[2]

Q. Why are PIMs appropriate for National Grid, given that the Company has multiple statutory and regulatory obligations to provide service to customers and maintain the distribution grid; including the overall obligation to provide safe, reliable, clean, and affordable electricity services?

A. First, PIMs encourage utilities to focus on specific outcomes or goals that warrant additional attention from a policy perspective, even if those outcomes or goals are consistent with historical core performance areas. Utility management must balance multiple objectives, and may need regulatory guidance and incentives to help prioritize outcomes or goals that are important to the Commission.

Second, utilities currently have a financial incentive to maximize profits by expanding capital investments and increasing rate base.[3] This can lead to lead to undue emphasis on capital investments, resulting in projects that are not least-cost for customers. PIMs can be used to offset these financial incentives, and are thus a critical

[2] Although the incentive may be expressed in terms of basis points, achievement of the incentive would be implemented through the utility collecting the dollar equivalent, rather than by actually increasing the utility's allowed ROE.

[3] This incentive exists where the utility's authorized ROE exceeds the cost of capital, as is often the case.

step toward establishing a new utility business model more aligned with power sector transformation.

Third, PIMs can be used to encourage a utility to undertake a particular project (such as a PST initiative) in a way that is most efficient, with reduced costs or increased benefits or both, relative to what would occur in the absence of a PIM.

Q. The Division addressed PIMs in the Power Sector Transformation Phase I Report. Does the current proposal differ from that described in the PST Report?

A. Yes. Although the overall approach to PIMs remains consistent, the proposal has naturally evolved since November 2017 based on information gained from the Company through the discovery process and from the analysis described in this testimony and manifest in Exhibit 4.

4. THE DIVISION'S PERFORMANCE INCENTIVE MECHANISM PROPOSAL

4.1. Summary of the Division PIM Proposal

Q. Please provide a brief summary of the Division's PIM proposal.

A. The Division's proposal is summarized in Table 2, Table 3, Table 4, and Figure 1. Our proposal builds off National Grid's PIM proposal in many ways. The primary areas where we deviate from the Company are in some of the baselines, some of the metrics, some of the targets, and in the BCA used to determine PIM incentives. Additional details for the Division's proposal are provided in Sections 4.4, 4.5, and 4.6 below.

Table 2. The Division's Proposed PIMs

Type	PIM	Description
System Efficiency	Transmission Peak	Reduce monthly transmission peaks relative to forecast
	FCM Peak	Reduce annual FCM peak relative to forecast
Distributed Energy Resources	Demand Response – Res.	Increase MW enrollment in cost-effective DR
	Demand Response - C&I	Increase MW enrollment in cost-effective DR
	Electric Heat Initiative	Reduce GHG emissions relative to baseline
	Electric Vehicle Initiative	Reduce GHG emissions relative to baseline
	Behind-the-Meter Storage	Install MW of cost-effective storage
	Utility-Scale Storage	Install MW of cost-effective storage
	Non-Wires Alternatives	Procure cost-effective NWA from third-parties
PST Support	Low Income: Participation	Increase LI participation in DER initiatives
	Low Income: Enrollment	Increase customer enrollment in LI rate A60
	Customer Information	Provide key data to customers and third-parties
	Peak Demand Forecasting	Improve and expand current forecasting practices

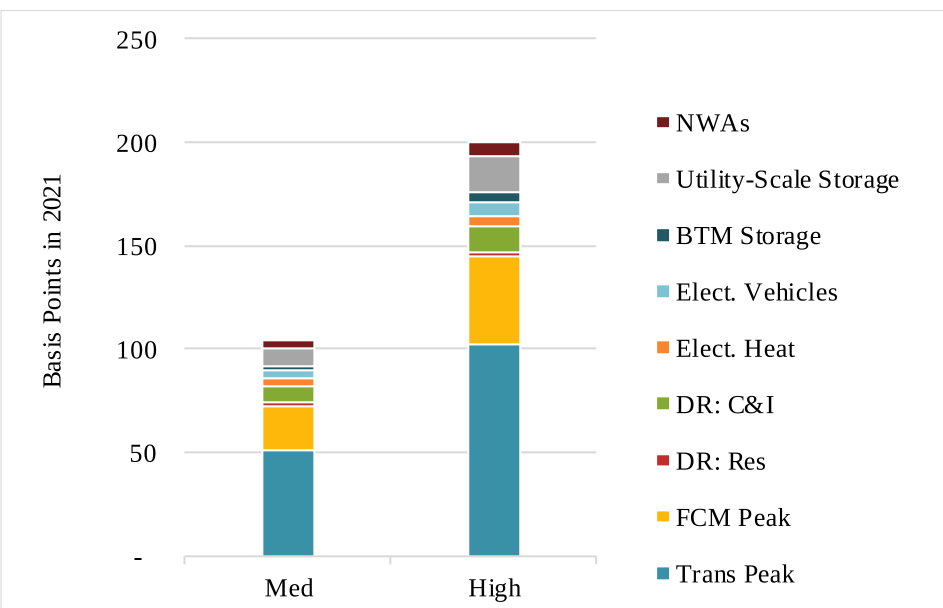
Table 3. Division's Proposed PIM Targets

Type	PIM	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
System Efficiency	Transmission Peak (Avg MW/mo)	21	31	23	35	26	39
	FCM Peak	29	44	31	46	32	48
	Subtotal						
Distributed Energy Resources	DR: Residential (MW)	1	2	2	3	3	4
	DR: C&I (MW)	8	14	10	16	12	18
	Electric Heat Initiative (GHG)	464	556	580	696	595	714
	Electric Vehicles (GHG)	557	1,114	757	1,511	1,026	2,051
	BTM Storage (MW)	1	2	1	2	1	2
	Utility-Scale Storage (MW)	3	6	3	6	3	6
	Non-Wires Alternatives (MW)	3	6	3	6	3	6
	Subtotal						
PST Support	LI: PST Participation						
	LI: Enrollment						
	Customer Information						
	Peak Forecasting						
	Subtotal PST Support						
Total							

Table 4. Division's Proposed PIM Incentives (bps)

Type	PIM	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
System Efficiency	Transmission Peak	40	80	46	93	51	103
	FCM Peak	9	18	15	30	21	42
	Subtotal	49	98	61	122	73	145
Distributed Energy Resources	DR: Residential	1	1	1	1	1	2
	DR: C&I	3	4	5	8	8	12
	Electric Heat Initiative	3	5	4	5	4	5
	Electric Vehicles	3	4	3	6	4	7
	BTM Storage	1	3	2	3	2	4
	Utility-Scale Storage	3	7	6	12	9	17
	Non-Wires Alternatives	2	4	3	6	4	8
	Subtotal	16	27	24	41	32	55
PST Support	LI: PST Participation	2	3	2	3	2	3
	LI: Enrollment	2	3	2	3	2	3
	Customer Information	1	2	0	0	0	0
	Peak Forecasting	1	2	0	0	0	0
	Subtotal PST Support	6	10	4	6	4	6
Total		71	135	89	169	108	206

Figure 1. Division's Proposed PIM Incentives in 2021 (bps)



4.2. Implications for the Authorized Return on Equity

Q. Why is it important to consider the Company's authorized ROE in conjunction with performance incentive mechanisms?

A. As described above, the Company's authorized ROE and PIMs serve similar and inter-related functions. They both provide revenues for the Company's shareholders, for the rate year and all the years until the next rate case. They also both provide utility management with financial incentives that can have a large impact on utility performance, utility rates, and services to customers. Because of this inter-relationship, it is critical for the Commission to consider the authorized ROE and the PIMs together; otherwise the ultimate impacts of these two mechanisms treated separately could lead to unintended consequences, uneconomic decision-making; undesirable performance outcomes, and over-recovery (or under-recovery) of revenues by the Company.

Q. Please expand upon the implications of the financial incentive provided by the authorized ROE and the PIMs.

A. As discussed the direct testimony of Mr. Woolf, utilities subject to traditional rate of return regulation have a financial incentive to increase profits by increasing capital expenditures and increasing their rate base. This incentive can lead to uneconomic decision-making as a result of an overstated incentive to increase rate base, as well as too much emphasis on capital costs at the expense of operations and maintenance impacts. This preference to increase rate base can significantly dampen a utility's incentive to invest in DERs and other PST initiatives that can reduce capital costs. In order to fully achieve the goals of power sector transformation, it will be necessary to mitigate this undue preference for increased capital costs. PIMs offer a logical mechanism for doing so.

Q. Please describe how PIMs can mitigate a utility's preference for capital costs.

A. PIMs provide a utility with an alternative source of shareholders revenues. This can dampen a utility's emphasis on capital costs by providing another way to increase profits; ideally in a way that is more consistent with regulatory goals.

In addition, since PIMs provide an alternative source of shareholder revenues, regulators can establish the authorized ROE at the lower end of the cost of equity range to reflect those additional revenues that will increase profits. In our view, this is one of the most effective ways to modify the regulatory model to provide a utility the incentives it needs to achieve power sector transformation objectives.

Q. Please elaborate on what you mean by establishing the authorized ROE at the lower end of the range to reflect PIM revenues.

A. Mr. Kahal, addresses the appropriate way to determine an authorized ROE for National Grid in this rate case. Here, we will touch upon some of the key issues that pertain to the PIM revenues.

Setting the authorized ROE is not an exact science, and there are many techniques that can be used to identify the best value. Each of these techniques has strengths and limitations, and commissions are frequently presented with a range of reasonable recommendations for the authorized ROE. Commissions will typically select a number within this range, with the goal of balancing customer and shareholder interests.

In this context, the Commission could select an authorized ROE that is at the lower end of a reasonable range, in order to reflect the revenues that a utility is expected to recover through its PIMs. This lower authorized ROE could also be justified because the PIMs reduce the utility's risk by providing regulatory guidance and some assurance that the costs associated with PIM initiatives will be allowed into rates.

Q. Are you recommending that the authorized ROE be lowered by the same number of basis points that the Company is allowed to earn from the PIMs?

A. No. We are not necessarily recommending a one-for-one transfer of basis points from the authorized ROE to the PIMs. As described above, there are some significant uncertainties in the magnitudes of the PIM incentives proposed by the Company and by us. Further, some of the PIMs incentives are for innovative initiatives that might not provide net benefits to customers or utility incentives in the early years. We recommend that the authorized ROE be set a level sufficiently below the expected PIM incentives, to ensure that shareholders are not exposed to the risk of not recovering enough revenues.

Q. Is there evidence from existing PIMs that suggests that reducing the Company's authorized ROE is warranted?

A. Yes. The Company has been subject to an energy efficiency PIM since 1990. In our view, the energy efficiency PIM is very robust in terms of the estimates of the costs, benefits, net benefits, and targets, all of which are vetted by stakeholders in multiple forums and are documented with independent evaluation, measurement, and verification studies. The energy efficiency programs and PIM have clearly resulted in significant net benefits to customers over many years.

The energy efficiency PIM has also increased the Company's earned ROE. Table 5 presents the Company's earned ROE for recent years for which data is available, and breaks out the impact that the EE incentive has on earned ROE. As indicated, in the past three years the EE incentive helped increase the Company's earned ROE by 95 to 98 basis points. This is a significant impact on earned ROE, which demonstrates that the revenue from PIM incentives can create room for the Commission to establish a lower authorized ROE without harming utility shareholders. It also demonstrates the importance of considering PIM incentives and authorized ROE together.

Table 5. National Grid Earned ROEs: Including and Excluding the EE Incentive

Year	Earned ROE Excluding EE Incentive	Earned ROE Including EE Incentive	Basis Point Value of Earned EE Incentive
2013	6.98%	7.57%	59
2014	7.52%	8.50%	98
2015	8.28%	9.24%	96
2016	5.84%	6.79%	95

Q. What is the potential amount of basis points that the Company might earn from all the PIMs proposed by the Division?

A. Table 6 provides a summary of the amount of basis points that the Company could earn under the Division's proposed PIMs. It also includes the basis points that the Company could earn from the existing EE PIM, and all the PIMs combined.

Table 6. Potential Incentive Earnings from PIMs (basis points)

Performance Incentive Mechanism	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Division's Proposed PIMs	71	135	89	169	108	206
Existing Energy Efficiency PIM	105	105	90	90	86	86
Total PIMs	176	240	179	259	194	292

As indicated, the Company will have the opportunity to earn 176 to 194 basis from the existing and proposed PIMs for achieving the medium targets. The incentives could be considerably higher for achieving the high targets.

4.3. Principles and Methodology for Developing the Division's Proposal

Q. In general, what principles should be used when designing PIMs?

A. Table 7 below presents a summary of the key principles that should be applied when designing PIMs, including principles related to (a) identifying policy goals; (b) establishing metrics; (c) establishing performance targets; and (d) establishing rewards and penalties.[4]

[4] These are taken from Synapse Energy Economics, *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, Prepared for the Western Interstate Energy Board, March 2015, page 4.

Table 7. Key Principles for Developing Performance Incentive Mechanisms

Policy Goals	• Articulate policy goals • Recognize financial incentives in the existing regulatory system • Design incentives to modify, supplement or balance existing incentives • Address areas of utility performance that have not been satisfactory or are not adequately addressed by other incentives
Performance Metrics	• Tie metrics to policy goals • Clearly define metrics • Ensure metrics can be readily quantified using reasonably available data • Adopt metrics that are reasonably objective and largely independent of factors beyond utility control • Ensure metrics can be easily interpreted and independently verified
Performance Targets	• Tie targets to regulatory policy goals • Balance costs and benefits • Set realistic targets • Incorporate stakeholder input • Use deadbands to mitigate uncertainty and variability • Use time intervals that allow for long-term, sustainable solutions • Allow targets to evolve
Rewards and Penalties	• Consider the value of symmetrical versus asymmetrical incentives • Ensure that any incentive formula is consistent with desired outcomes • Ensure a reasonable magnitude for incentives • Tie incentive formula to actions within the control of utilities • Allow incentives to evolve

Q. Please describe the specific principles that you used in developing the PIMs for National Grid.

A. We generally agree with the principles that the Company used in designing its PIMs:[5]

- Establish incentives that will appropriately reward the Company for successful delivery of activities, programs, investments, and outcomes that are foundational to power sector transformation;
- Align, to the extent possible, with the proposed performance incentive mechanisms in the Power Sector Transformation Phase One Report; and

[5] PST Panel Direct Testimony, January 12, 2018, page 88.

- Assign values to individual performance incentive mechanisms based on a combination of (1) relevance to developing a foundation for transforming the power sector in the near term, and (2) the associated benefits or savings to customers due to the activity encouraged by the incentive.[6]

We also applied several additional, more specific principles in designing the Division's PIMs:

- Establish a portfolio of PIMs that is as simple and transparent as possible. This is particularly important because some of the Company's PIM proposals are complex and opaque.
- Establish a portfolio of PIMs that has an appropriate balance between outcome-based (e.g., system efficiency), program-based (e.g., distributed energy resources), and action-based (e.g., data access). Each of these types of PIMs has different strengths and challenges, so it is best to use a balanced mix of them.
- Establish at least one PIM for each of the DERs that are expected to play a foundational role in power sector transformation over the long-term. This is necessary to send a signal to the Company of the importance of each type of DER.
- Establish metrics and targets that are as concrete and as directly related to the desired outcomes as possible. This is particularly important here because some of the Company's proposed PIM targets are not directly related to the desired outcomes.

Q. Please describe how you determined the magnitude of the incentives for each of the PIMs you propose.

A. Determining the magnitude of incentives is one of the more challenging aspects of designing PIMs. Ideally, a PIM incentive should be designed to ensure that it will result in net benefits to customers. This requires first estimating the benefits and the costs of the

[6] PST Panel Direct Testimony, p. 88, lines 12-20.

initiative or action that the PIM applies to, and then deciding upon the appropriate portion of the net benefits to provide to the utility relative to the customers. This was essentially the approach that National Grid used in designing its proposed incentives.

We used the same approach in designing our incentives. However, given that our PIMs are structured somewhat differently from the Company's, and given that we have some concerns about National Grid's BCA assumptions, we developed PIM incentives independently from the Company's. We took the following steps:

- Update or otherwise modify the avoided costs that National Grid used in its BCAs. This includes using more recent information on forecast FCM prices, energy prices, and transmission costs. It also includes adding in our own assumption for avoided distribution capacity costs.
- Apply those new avoided costs to the PIM targets to estimate the quantitative benefits expected from achieving each of the PIMs in terms of peak demand reductions, peak energy savings, and greenhouse gas emissions. For each PIM, we made assumptions regarding the extent to which the utility's actions would reduce FCM, transmission, and distribution system peaks (using assumed coincidence factors).
- Estimate the likely costs of each of the PIM initiatives, to estimate the PIM's quantitative net benefits.
- Assume a percentage of net benefits to be shared between the Company and its customers, to estimate a dollar value for the PIM incentive.
- Convert this dollar value of the PIM incentive into basis points for the Company. For this purpose we used the Company's information for the value of a basis point.
- Identify additional unquantified benefits associated with each of the PIMs. These were assumed to be in the form of (a) improved reliability or resilience; (b) other

fuel benefits; (c) market innovation or transformation benefits; or (d) low-income benefits.

- Assign basis points for these unquantified benefits. The number of basis points for each PIM was chosen based upon the type and number of unquantified benefits, and the importance of each unquantified benefit in light of Docket 4600 goals and state energy policies.
- Add the basis point incentives for the quantified benefits to those for the unquantified benefits, to determine the total basis point incentive.

Additional details and assumptions underlying these steps are provided in Exhibit TW/MW-3.

Q. How did you incorporate the objective of ensuring consistent compensation for benefits across various performance incentive mechanisms?

A. We achieved a significant degree of consistency. The methodology to determine the magnitude of PIM incentives includes as a common input the benefits related to FCM capacity, distribution, greenhouse gas emission reductions, transmission, and energy. Those benefits populate our workbook consistently across individual performance incentive mechanisms.

Q. The methodology you describe for determining the magnitude of the PIM incentives includes multiple assumptions and estimates. Please comment.

A. Given that the magnitude of the PIM incentives should be based as much as possible on the net benefits, and given that the initiatives that the PIMs are applied to can be new or innovative, there is naturally a need to make some assumptions and estimates to determine those net benefits.

Q. Please describe those assumptions and estimates that are mostly likely to affect the results of your analyses.

A. The assumptions and estimates that are mostly likely to affect the results of our analyses include the following:

- Avoided FCM, energy, and transmission costs. These will have a large impact on the benefits of the PIM initiative. We have used recent values from an analysis provided at our request by Daymark Energy Advisors which we reviewed and believe is very reasonable. We are confident that these assumptions are robust for our purposes.
- Avoided distribution costs. The Company chose to not include these benefits, because of the challenges of estimating a value. We are concerned that this decision ignores a potentially significant benefit from DERs. Therefore, we have assumed the same avoided transmission costs that are used for evaluating energy efficiency cost-effectiveness in Rhode Island. We recognize that this number is a rough approximation, and that the value is likely higher for some distribution circuits and lower for others.
- Cost of the PIM initiative. The cost of an initiative or technology will clearly have a large impact on its net benefits. For the FCM Peak and Transmission Peak PIMs we assumed that there will be no additional cost to the customers, because the Company has not requested recovery of any such costs in this rate case. For some of the PIM initiatives (e.g., residential demand response, behind-the-meter storage), the costs are not known at this time. Our cost estimates are based on our understanding of the general cost-effectiveness of the relevant technology or initiative.
- PIM initiative or technology measure life. This assumption can have a very large impact on the estimated benefits of a PIM initiative. Some of the actions taken in the PIM initiatives might have measure lives of only one year (e.g., a demand response program), while others could have measure lives of ten or twenty years

(e.g., electric vehicles or electric heating). Our measure life assumptions are based on our understanding of the technologies and practices that are likely to be used in each PIM initiative.

- Coincidence of a PIM initiative or technology with the FCM, transmission, or distribution system peak. These coincidence factors are likely to vary across initiatives and technologies, and can have a very large impact on the estimated benefits of a PIM initiative. Our coincidence estimates are based on our understanding of the likely operating parameters of the relevant technology.

Q. Given all these assumptions and estimates that can significantly affect the outcome of your analysis, are you confident that your analysis can be used at this time to determine the magnitude of PIMs for National Grid?

A. Yes. There is no question that additional time and analyses will result in more robust assumptions than those that we have used here. Nonetheless, our assumptions and estimates are reasonable for our purpose here, for two reasons. First, in designing our PIMs we have used a shared savings approach as much as possible to determine the magnitude of the PIM incentives. A shared savings approach will provide the Company with a certain portion of the net benefits of achieving a PIM target. The net benefits will be determined after the year in which the target was achieved, at which time the actual costs of the actions taken by the Company will be known. This approach means that, for PIMs with a shared savings approach, the Company will only be awarded PIM incentives if there are actual net benefits to customers. It also means that the magnitude of the PIM incentive will depend upon the magnitude of the net benefits.

Second, as discussed in Section 4.7, the PIMs that we are proposing here would not take effect until January 2019, and would be preceded by a filing from the Company that provides up-to-date information, assumptions, and estimates on all aspects of the

PIMs, including the estimates of net benefits. The analyses that are presented in our testimony are illustrative but are not the final analyses that should be used to set the PIM incentives. Consequently, they are sufficiently robust for the Commission to take the next step on the proposed PIMs and direct the Company to file more detailed PIM proposals at a later date.

Q. Do you propose to include any penalties in your PIMs?

A. No. There are several reasons why we prefer to not apply penalties for the PIMs we propose here, primarily based on our findings from energy efficiency PIMs applied in other states. First, the initiatives that we are asking the Company to undertake are somewhat new. This means that there is some uncertainty about the costs, the benefits, and the outcomes of the initiatives. In this context, assigning penalties to the PIMs will be more likely to discourage the Company from pursuing an initiative than encourage it.

Second, if the Company is likely to be subjected to penalties for not achieving a specific PIM target, then it will be less likely to propose aggressive, or even reasonable, targets.

Third, applying penalties can be much more contentious than applying rewards. Having to return revenues that the Company was otherwise planning to retain can be a very undesirable outcome for utility management, and they might be more inclined to challenge any such penalty.

Q. Do you offer any other modifications to the Company's proposal?

A. Yes, a minor but important modification. The Company proposes PIM targets for minimum, target, and maximum levels. For any PIM in which there are shared savings, there is no need to cap targets (and associated incentives) at a maximum level. If the Company can increase net benefits associated with a PIM initiative by exceeding the maximum target, then it should be encouraged to do so. For this reason, we refer to the highest target level as the “high” target, instead of the “maximum” target. We also refer to the middle target as the “medium” target, instead of the “target.”

4.4. Division’s Proposed System Efficiency PIMs

Q. Please summarize your rationale for the system efficiency PIMs.

A. System efficiency PIMs can play an important role in the total portfolio of utility PIMs. The system efficiency PIMs proposed here can be described as “outcome-based,” because they focus on the desired outcome, rather than on the means to achieve that outcome. This approach is fundamentally different than “program-based” PIMs, such as the DER PIMs described below, which are implemented through specific initiatives or programs.

Outcome-based programs require relatively little regulatory oversight as they allow the utility to determine the best way to achieve the desired outcome. The advantage of this is that the utility has a lot of flexibility to be creative and innovative in achieving the desired outcome. The disadvantage of this approach is that regulators have much less opportunity to identify, monitor, and evaluate the actions taken by the utility to achieve the outcome.

Program-based PIMs, on the other hand, require relatively more regulatory oversight in order to ensure that the programs are cost-effective, properly funded, and executed efficiently.[7] The advantage of this approach is that regulators can have more involvement, certainty, and confidence in the program and the related PIM. The disadvantage of this approach is that it might constrain the utility's creativity, and the regulatory oversight might be overly cumbersome.

Because of these different strengths and limitations of the two types of PIMs, we recommend a balanced approach that includes them both. This should offer the right amount of regulatory oversight and guidance, while enabling the utility to be creative and innovative.

Q. Please describe the Division's proposal for an FCM Peak Demand Reduction PIM.

A. Company activities to reduce FCM peak demand could significantly reduce generation capacity costs and play a foundational role in achieving power sector transformation objectives. Under current ratemaking practice, National Grid has little financial incentive to reduce FCM peak demand, because FCM costs are entirely passed on to customers. An FCM PIM can help create such an incentive while also creating net benefits to customers.

We propose that the metric for the FCM PIM be the reduction in demand (in MW) for the single peak FCM hour for each year. The demand reduction would be calculated as the difference between a forecasted baseline FCM peak and the actual FCM peak for that year, rather than year-over-year reductions relative to 2018 peak, as proposed by the Company. Both the baseline and the actual peaks would be calculated in weather-normalized terms. The baseline should also include the impacts of DERs that

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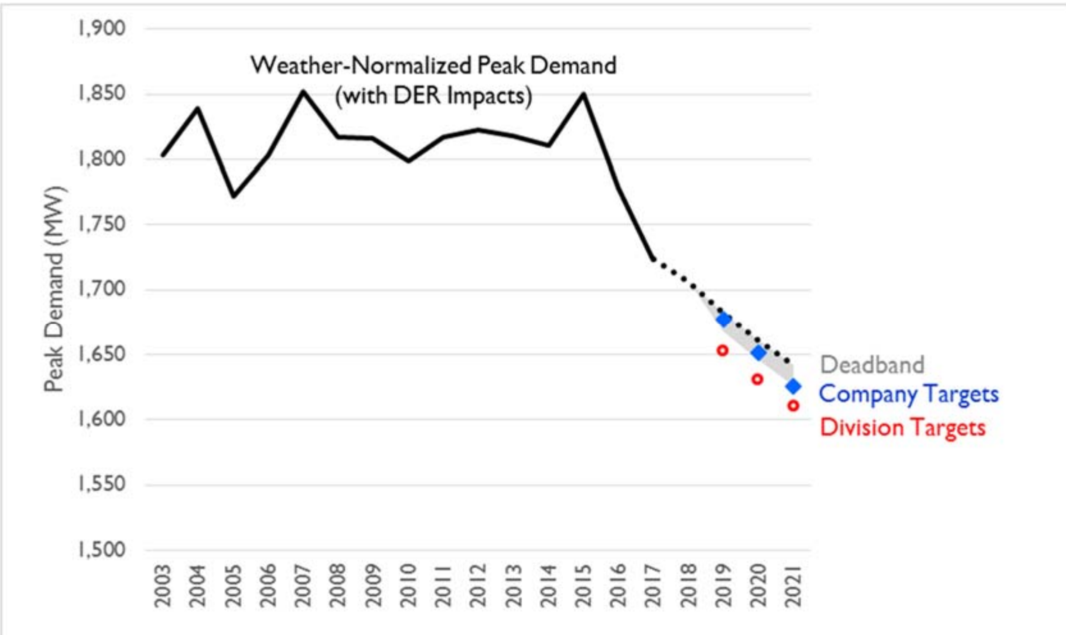
[7] Consider, for example, the regulatory oversight of the energy efficiency programs in Rhode Island.

the Company would be expected to earn an incentive for, so that there is no double-counting of savings.

For the weather-normalized baseline, we have used the Company's forecast of FCM peak demand for 2019, 2020, and 2021, including expected impacts from energy efficiency, solar PV, storage, VVO, and electric vehicles.[8] The peak demand forecast, along with our proposed deadband and PIM targets are presented in Figure 2.

Figure 2. FCM Peak Demand: Historical, Forecast, Deadband, and Targets



To account for uncertainty in the forecast and to ensure that the target is not something that could be met too easily by the utility, we propose a deadband equal to 0.5 standard errors of the forecast for each year.[9] We propose that the medium targets for the

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[8] The Company provided these values in response to DIV 8-5. To illustrate, the Company's reconstituted forecast included load growth from 2018 to 2019 of 22.7 MW. However, the Company expects there will be 46.3 MW of load reductions through energy efficiency (35 MW), solar PV (7 MW), VVO (3 MW), and storage (1 MW). Because the Company proposes to earn incentives for these activities through other PIMs, we reduced the baseline by 46.3 MW, for a net reduction of 23.6 MW (22.7 – 46.3= -23.6).

[9] The standard error is a measure of the accuracy of the model, based on the difference between the model's estimated values and the actual values. For example, assuming a normal distribution with 10 degrees of freedom, 1.0 standard error is associated with an 83 percent level of confidence. This means that there is an 83 percent chance that a deviation from the

FCM PIM be set at 1.0 standard error below the forecast. This value of the standard error suggests that there is an 83 percent chance that the Company was responsible for the outcome. We also propose that the high target be set to 1.5 standard errors, which suggests that there is a 92 percent chance that the Company was responsible for the outcome. These targets are presented in Table 8. Note that these targets are relative to the baseline, including impacts from energy efficiency, solar PV, and other utility programs for which the Company proposes to earn an incentive. This means that, for example, in year 2019 the Company will need to reduce peak demand by 29 MW beyond the deadband. In that year the deadband amount is approximately 14.5 MW, which means that the Company will need to reduce FCM peak demand by 43.5 MW in order to reach this target.

We propose that the incentives for the FCM PIM be equal to 50 percent of the quantified net benefits of the FCM reductions achieved. We do not propose any additional basis points for unquantified benefits associated with FCM peak reductions, because we are not aware that there are any. These FCM incentives are presented in Table 8.

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forecast is likely to be due to *something other than* the explanatory variables in the model, such as weather or the economy. In the context of defining PIM targets, a 1.0 standard error means that there is an 83 percent chance that the utility was responsible for the outcome.

Table 8. FCM Peak Demand Reduction PIM – Targets and Incentives

FCM Peak Demand Reduction	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (annual peak FCM MW savings)	29	44	31	46	32	48
Incentive for Quantified Benefits (bps)	9	18	15	30	21	42
Incentive for Unquantified Benefits (bps)	-	-	-	-	-	-
Total Incentive (bps)	9	18	15	30	21	42

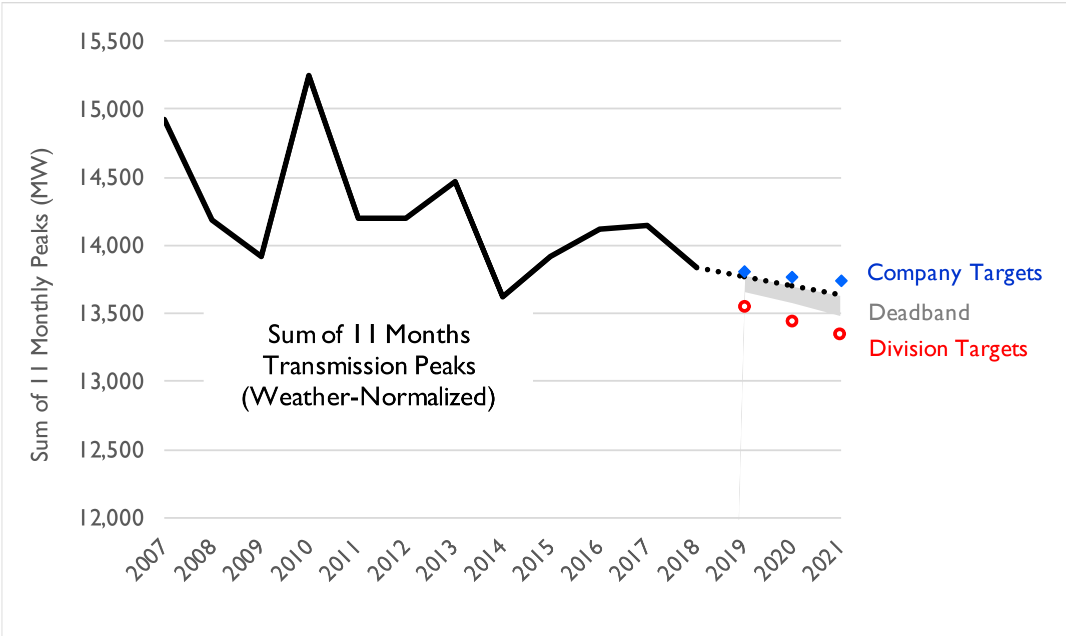
Q. Please describe the Division's proposal for a Transmission Peak Demand Reduction PIM.

A. Company efforts to reduce transmission peak demands could significantly reduce transmission costs and play a foundational role in achieving power sector transformation objectives. Under current ratemaking practice, National Grid has little financial incentive to reduce transmission peak demand, because these costs are entirely passed on to customers. A PIM can help create such an incentive while also creating net benefits to customers.

We propose that the metric for the Transmission PIM be the sum of monthly peak demands for each year, excluding the highest peak month. We exclude the highest month to avoid double-counting, as this month is when the FCM peak demand occurs, and the peak demand reductions in that month will be counted towards the FCM PIM. The 11-month transmission peak demand reduction would be calculated as the difference between a baseline of transmission peaks and the actual transmission peaks. Both the baseline and the actual peaks would be calculated in weather-normalized terms.

We propose that the baseline for the Transmission PIM be the 11-month sum of forecasted weather-normalized peak demand for the year in question rather than year-over-year reductions, as proposed by the Company. The Company's historical transmission peak demand, along with our forecast, proposed deadband, and PIM targets are presented in Figure 3.

Figure 3. Transmission Peak Demands: Historical, Our Forecast, Deadband, and Targets



The Company does not have a weather-normalized transmission peak demand forecast.[10] In addition, the Company has not weather-normalized its historical transmission peak data.[11] Without having weather-normalized historical data or a forecast of future transmission peak demand, it is not possible to set a reasonable target or determine with any certainty whether transmission peak reductions are the result of utility action or some other factor.

In order to develop more reasonable targets for this PIM, we developed a weather-normalized forecast for transmission peaks by regressing 11 years of transmission peak

[10] Response to (Docket 4770) Division 25-12.

[11] Response to (Docket 4770) Division 25-14

data[12] on various weather variables. We tested for multicollinearity and goodness of fit, and selected the model containing the explanatory variables of cooling degree days (CDD), heating degree days (HDD), and year. The model had an adjusted R^2 of 0.67.

The regression coefficients from this model were then used to create a weather-normalized historical baseline and to forecast a 2019 – 2021 baseline. Once the baseline was constructed, it became apparent that the Company's targets were inadequate, as they lay *above* the forecast, implying that the Company would be rewarded for doing nothing at all.

To create reasonably aggressive targets, a deadband was created by subtracting 0.5 standard errors associated with each prediction for years 2019 – 2021 from that year's weather-normalized baseline. Achieved reductions that lie within the deadband are too small to say with certainty whether utility action had an effect on the reduction.

Similar to the FCM PIM targets, the Division proposes to establish targets for the transmission peak demand PIM at 0.5 standard errors, 1.0 standard error, and 1.5 standard errors for the minimum, medium, and maximum targets, respectively. For clarity, these targets are presented in Table 9 in terms of the sum of 11 months of reductions, and as average monthly MW reductions.

The Company should be compensated only for peak reductions that fall below the deadband, which means that, for example, in year 2019 the Company will need to reduce peak demand by 228 MW beyond the baseline (equivalent to 21 MW on a monthly

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[12] Monthly data were collapsed into an annual sum of monthly transmission peaks, excluding the maximum month.

basis). In that year the deadband amount is 114 MW (equivalent to 10 MW on a monthly basis).

We propose that the incentives for the Transmission PIM be equal to 50 percent of the quantified net benefits of the transmission peak reductions achieved. We do not propose any additional basis points for unquantified benefits associated with FCM peak reductions, because we are not aware that there are any. These Transmission PIM incentives are presented in Table 9.

Table 9. Transmission Peak Demand Reduction PIM Summary

Transmission Peak Demand Reduction	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (sum of 11 monthly peaks (MW))	228	342	255	383	284	425
Targets (average monthly reduction (MW))	21	31	23	35	26	39
Incentive for Quantified Benefits (bps)	40	80	46	93	51	103
Incentive for Unquantified Benefits (bps)	-	-	-	-	-	-
Total Incentive (bps)	40	80	46	93	51	103

4.5. Division's Proposed Distributed Energy Resource PIMs

Q. Please summarize your rationale for the proposed DER PIMs.

A. There is a wide variety of DERs available today for customers or the Company to take advantage of. The various types of DERs have different levels of commercial development, economic viability, and customer acceptance. Each type of DER is expected to play an important role in power sector transformation over the long-term. Accordingly, we believe it is appropriate to establish at least one PIM at this time for each type of DER.

For some types of DERs, such as C&I demand response and electric heat, the associated initiative and potential benefits are fairly well established and will likely offer significant net benefits between now and the next rate case. For other types of DERs, such as behind-the-meter storage, the associated initiative and potential benefits are not yet well established and thus may have a relatively small impact prior to the next rate case. We recommend establishing at least one PIM for each type of DER, even if the PIM might have a small impact in the short-term, because that sends an important signal to the Company that it should be investigating opportunities for all types of DERs.

Q. Please describe the Division's proposal for a Residential Demand Response PIM.

A. Residential demand response is expected to play an important role in reducing peak demands and helping to achieve power sector transformation objectives. The Company's residential demand response program "Connected Solutions" is in an early phase and does not appear to be cost-effective, based on the data provided by the Company.[13] However, National Grid is developing a more robust program for the 2019 Energy Efficiency Plan. The opportunities for demand response program will expand considerably if and when the Company installs AMF. Therefore, we propose a Residential DR PIM where the incentive is based on shared savings, to encourage the Company to develop a more cost-effective program, and to implement it as efficiently as possible.

We propose that the metric for the Residential DR PIM be equal to the amount of peak demand (in MW) that customers have signed up to reduce through participation in

[13] Response to (Docket 4770) Division 1-39

the Residential DR program. Ideally, the metric would be the actual amount of capacity that was reduced by customers as a result of the program. However, this amount might depend upon the wholesale market prices during peak periods, which are beyond the control of the Company.[14] Instead, we propose that the targets be based on enrolled capacity, but that the Company also provide an annual report regarding the number of events called and the estimated demand reductions achieved each year.

The targets we propose for this PIM are presented in Table 10. These are based on our expectation of the capacity that the Company might enroll through the Residential DR program. The baseline for this PIM is simply zero, because there would be no residential DR without the program.

The incentives we propose for this PIM are presented in Table 10. As indicated in the table, we expect the quantified net benefits to be relatively small due to the relatively small size of the program and our cost assumptions. Once these net benefits are shared equally between the Company and the customers, the amount of the Company's incentive is less than one basis point. We add one basis point incentive targets achieved in each year to reflect the unquantified benefits expected to result from residential demand response programs. These unquantified benefits include improved reliability and the development of markets and products related to residential demand response and home energy management in general. For example, sophisticated thermostats enrolled in the Connected Solutions program can be expected to provide energy savings as well as capacity benefits.

[14] It is possible that demand response events would not be called at all during mild summers.

Table 10. Residential Demand Response: Targets and Incentives

Demand Response – Residential	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental MW savings)	1	2	2	3	3	4
Incentive for Quantified Benefits (bps)	-	-	-	-	-	1
Incentive for Unquantified Benefits (bps)	1	1	1	1	1	1
Total Incentive (bps)	1	1	1	1	1	2

Q. Please describe the Division's proposal for a C&I Demand Response PIM.

A. Commercial and Industrial (C&I) demand response is expected to play an important role in reducing peak demands and helping to achieve power sector transformation objectives. The Company's C&I demand response program has been very cost-effective to date.[15] We propose a C&I DR PIM where the incentive is based on shared savings to encourage the Company to expand its C&I DR program cost-effectively.

We propose that the metric for the C&I DR PIM be equal to the amount of peak demand (in MW) that customers have signed-up to reduce through participation in the C&I DR program. Ideally, the metric would be the actual MW reductions provided by customers as a result of the program. However, this amount might depend upon the wholesale market prices during peak periods, which are beyond the control of the Company.

The targets we propose for this PIM are presented in Table 11. These are based on a moderate scaling up of the existing C&I DR program. The baseline for this PIM is simply zero, because there would be no DR contracts with customers without the DR program.

[15] Based on our analysis of response to (Docket 4770) Division 3-14.

The incentives we propose for this PIMs are presented in Table 11. This program is expected to result in a modest amount of net benefits, which lead to incentives based on quantified net benefits of 2 to 3 basis points, increasing to 7 to 11 basis points in later years. Further, given that there are additional unquantified benefits (such as reliability and resiliency and market transformation, particularly with respect to new "smart" devices that help customers manage their demand and energy consumption), we propose that the Company be eligible to earn an additional basis point in incentives for achieving its targets. Thus, the range of total basis points is 3 to 4 bps in 2019 increasing to 8 to 12 basis points in 2021.

Table 11. Commercial and Industrial Demand Response: Targets and Incentives

Demand Response – C&I	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental MW savings)	8	14	10	16	12	18
Incentive for Quantified Benefits (bps)	2	3	4	7	7	11
Incentive for Unquantified Benefits (bps)	1	1	1	1	1	1
Total Incentive (bps)	3	4	5	8	8	12

Q. Please describe the Division's proposal for an Electric Heat PIM.

A. Electric heat is a key component of strategic electrification, which advances the goals of increasing energy efficiency and reducing greenhouse gases and other pollutants while lowering costs to customers and society. National Grid estimates that its Electric Heat initiative will be cost-effective, with a benefit-cost ratio of 1.4. [16]

We have developed targets based on the avoided CO_2 emission estimates contained in the Company's benefit-cost analysis for the Electric Heat Initiative.[17] These

[16] Response to (Docket 4770) Division 1-1-3, Attachment DIV 1-1-3.
[17] *Ibid.*

avoided CO_2 estimates are higher than those initially proposed by the Company for this PIM.

In addition to proposing higher targets for this PIM, we propose some modifications to the incentives. Most importantly, we propose a shared savings approach based on 50/50 sharing of net savings. We also add an additional 1 to 2 basis points to reflect unquantified benefits of reliability, market transformation, and low income benefits. The targets and incentives we propose for the Electric Heat PIM are presented in Table 12.

Table 12. Electric Heat Initiative: Targets and Incentives

Electric Heat	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental Avoided CO_2)	464	556	580	696	595	714
Incentive for Quantified Benefits (bps)	2	3	3	3	3	3
Incentive for Unquantified Benefits (bps)	1	2	1	2	1	2
Total Incentive (bps)	3	5	4	5	4	5

Q. Please describe the Division's proposal for an Electric Vehicle PIM.

A. Electric vehicles are another key component of strategic electrification. In addition to playing a key role in decarbonization, electric vehicles can save customers money and potentially provide grid services. For these reasons, we support a PIM for electric vehicles.

The Company's has baseline and targets for an electric vehicles PIM are generally reasonable. However, we prefer a metric that is more closely tied to the underlying policy goal of reducing greenhouse gases, rather than simply rewarding higher adoption levels of any type of electric vehicle. Such a metric will provide incentives for the Company to prioritize encouraging adoption of vehicles that reduce the most greenhouse gases. Therefore, we propose to convert the Company's baseline and targets into tons of greenhouse gases using the following methodology:

- The Company's proposed baseline was derived using the forecast growth rate for EV sales in New England from the US Energy Information Administration's Annual Energy Outlook 2017. This growth rate would be applied to actual sales in Rhode Island, as reported by the R.L. Polk Vehicles in Operation data source. This data source reports both battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs).
- To convert this baseline into greenhouse gas emissions avoided, we used the Company's assumptions contained in the PST Initiative Benefit Cost Analysis workbook (provided in response to DIV 1-1-3). The Company assumed that its EV initiative would result in an adoption rate of 30% battery electric vehicles and 70% plug-in hybrid electric vehicles. The weighted average quantity of greenhouse gases avoided annually per vehicle was estimated to be 3.5 tons. Multiplying 3.5 tons by the baseline number of EVs provides a baseline in greenhouse gas avoided emissions.
- The Company's targets were set to reflect a 20%, 40%, and 80% improvement over the baseline. We have applied the same improvements to greenhouse gas emissions to develop our proposed targets.

The Company's proposed reporting of performance (using the total number of new registrations in Company service territory during the calendar year based on data from the R.L. Polk Vehicles in Operation data source) would generally remain the same, except the number of each type of vehicle would then be multiplied by its respective assumed emissions avoidance factor. In addition, the Company would be required to report any adoption of fleet vehicles and provide assumed emissions avoidance for those vehicles.

In recognition that electric vehicle adoption is a goal with particularly high importance at this point in time, we have added an additional two basis points for achieving the medium targets and three basis points for achieving the high targets. These additional basis points are warranted given the substantial benefits provided by EVs, and the fact that EVs require a critical mass before the market can be transformed. The targets and incentives we proposed for this PIM are provided in Table 13.

Table 13. Electric Vehicle Initiative: Targets and Incentives

Electric Vehicles	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental Avoided CO_2)	557	1,114	757	1,511	1,026	2,051
Incentive for Quantified Benefits (bps)	1	1	1	3	2	4
Incentive for Unquantified Benefits (bps)	2	3	2	3	2	3
Total Incentive (bps)	3	4	3	6	4	7

Q. Please describe the Division's proposal for a Behind-the-Meter Storage PIM.

A. Behind-the-meter electricity storage systems represent a flexible resource that can provide important benefits to customers and the grid, including reducing peak demand costs; reducing peak energy costs; increasing reliability and resilience; supporting distributed generation, especially distributed solar; providing ancillary services; and enabling the integration of high penetrations of renewable energy.

We support the Company's proposal to implement a PIM for incremental MW of installed behind-the-meter storage. However, we propose that the incentives be awarded on a shared-savings basis to encourage the utility to promote cost-effective behind-the-meter storage, and to protect consumers if cost-effective options are not available during this time period.

The targets and incentives we propose for this PIM are provided in Table 14. The targets are slightly lower than those proposed by the Company, because our targets require that the resource be cost-effective. Behind-the-meter storage is only economic if customers have time-varying rates, which first require AMF. We therefore assume that the only behind-the-meter storage that will be developed over the next three years will be by commercial and industrial customers.

While the quantified benefits are expected to be small in this time period, we include some incentive for the unquantified benefits expected from (a) technology and market development, and (b) improved reliability and resilience.

Table 14. Behind-the-Meter Storage Initiative: Targets and Incentives

Behind-the-Meter Storage	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental MW)	1	2	1	2	1	2
Incentive for Quantified Benefits (bps)	-	1	1	1	1	2
Incentive for Unquantified Benefits (bps)	1	2	1	2	1	2
Total Incentive (bps)	1	3	2	3	2	4

Q. Please describe the Division's proposal for a Utility-Scale Storage PIM.

A. Utility-scale electricity storage systems represent a flexible resource that can provide important benefits to customers and the grid, including reducing peak demand costs;

reducing peak energy costs; increasing reliability and resilience; supporting distributed generation, especially distributed solar; providing ancillary services; and enabling the integration of high penetrations of renewable energy.

We support the Company's proposal to implement a PIM for incremental MW of installed utility-scale storage. However, National Grid's BCA indicates that utility-scale storage owned by the Company may not be cost-effective over the next three years.[18] Therefore, we recommend expanding this PIM to include any form of utility-scale storage, which could be owned by the Company or purchased from third-party providers. In addition, we propose that the incentives be awarded on a shared-savings basis to encourage the utility to promote cost-effective utility-scale storage, to protect consumers if cost-effective options are not available during this time period.

The targets and incentives we propose for this PIM are provided in Table 15.The targets are the same as those proposed by the Company. In addition to the incentives for quantified net benefits, we include some incentive for the unquantified benefits expected from (a) technology and market development, and (b) improved reliability and resilience.

[18] *Ibid.*

Table 15. Utility-Scale Storage: Targets and Incentives

Utility-Scale Storage	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental MW)	3	6	3	6	3	6
Incentive for Quantified Benefits (bps)	2	5	5	10	8	15
Incentive for Unquantified Benefits (bps)	1	2	1	2	1	2
Total Incentive (bps)	3	7	6	12	9	17

Q. Please describe the Division's proposal for a Non-Wires Alternative PIM.

A. Non-wires alternatives (NWA) include a set of DERs that are applied to a specific location on the grid to address a particular distribution system constraint. NWAs can help reduce distribution, transmission, and generation capacity costs, as well as help promote the deployment of new DER technologies. National Grid has implemented a pilot NWA project as part of the System Reliability and Procurement process since 2012, in the towns of Tiverton and Little Compton. In 2018 the Commission approved a PIM for the Tiverton-Little Compton NWA, which requires the Company to issue at least one RFP for vendors to provide bids for NWA projects. The Company will be allowed to keep a portion of the net benefits of any projects that are implemented as part of that effort.[19]

We propose to continue the existing NWA PIM for the next three years. Competitive bidding among third-party vendors creates an opportunity to identify cost-effective alternatives to distribution system needs that might not be identified by National Grid. We propose to continue the shared-savings approach used in the 2018 SRP to encourage the Company to seek the most cost-effective options, and to protect consumers if cost-effective options are not available during this time period.

[19] Cite 2018 SRP.

The targets and incentives we propose for this PIM are provided in Table 16. The targets are based on our assessment of the potential NWA savings that might be available in the next three years. In addition to the incentives for quantified benefits, we include some incentive for the unquantified benefits expected from technology and market development.

Table 16. Non-Wires Alternatives: Targets and Incentives

Non-Wires Alternatives	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental MW)	3	6	3	6	3	6
Incentive for Quantified Benefits (bps)	1	2	2	3	3	5
Incentive for Unquantified Benefits (bps)	1	2	1	2	1	2
Total Incentive (bps)	2	4	3	5	4	7

4.6. Division’s Proposed Power Sector Transformation Support PIMs

Q. Please summarize your rationale for the Power Sector Transformation Support PIMs.

A. We propose two PIMs to help protect low-income customers. The first is to encourage National Grid to increase low-income customer participation in all of the PST initiatives. The second is to encourage National Grid to increase the percent of low-income customers that are enrolled in the A60 low-income discount rate. These PIMs are important to enable low-income customers to enjoy the direct benefits of PST initiatives, and to protect them from potential rate increases.

We also propose two PIMs to encourage the Company to provide customer information and improve its distribution demand forecasting practices. These PIMs can be described as “action-based,” because they are focused on specific actions that the

Company can take to achieve desired outcomes. This type of PIM is different from outcome-based or program-based PIMs in that there may not be direct monetary benefit or net benefit associated with the action. Instead, the action is presumed to lead to other actions or outcomes that will provide net benefits to customers. Action-based PIMs are appropriate to encourage a utility to take steps that are foundational to power sector transformation objectives, but that the utility is unlikely to take without the PIM. Often this type of PIM is only necessary for a short time, to help facilitate a transition.

Q. Please describe the Division's proposal for a Low-Income PST Participation PIM.

A. Customers who participate in one of the Company's DER programs will experience direct benefits in terms of bill reductions. It is especially important to enroll low-income customers in such programs, to make their electricity bills more affordable. When a low-income customer's bill is more affordable they are more likely to pay their bills, which will reduce the bill arrearages that all customers pay for. Reduced low-income consumption and bills can also help reduce the amount of money that is used to pay for the low-income discount rate, which is also paid for by all customers.

We propose that the metric for the LI Participation PIM be the percent of low-income customers enrolled in any one of the Company's DER programs, including demand response, electric heat, electric vehicles, and electric storage. We exclude the Company's energy efficiency program from this PIM, because the Company already has a long history of promoting low-income energy efficiency programs.

The baseline for this PIM should be the percent of low-income customers relative to total residential customers.

The targets for this PIM should be based on DER program participation rates relative to the baseline percentage of low-income customers. We propose a medium target equal to a program participation rate that is five percent higher than the baseline percentage of low-income customers. Thus, if the baseline percentage is 15 percent, the medium target should be 20 percent participation of low-income customers in the relevant DER programs. For this calculation of program participation rate, low-income participation in all of the relevant DER programs can be combined. We propose the high target for this PIM equal to a program participation rate that is ten percent higher than the baseline percentage of low-income customers.

The low-income participation PIM does not have any benefits that can be readily quantified. Therefore, we propose an incentive based upon the unquantified benefits of improving low-income customer affordability and reducing utility arrearages. The targets and incentives we propose for this PIM are provided in Table 17.

Table 17. Low-Income PST Participation PIM: Targets and Incentives

Low Income PST Participation	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (percentage point increase)	5	10	5	10	5	10
Incentive for Quantified Benefits (bps)	-	-	-	-	-	-
Incentive for Unquantified Benefits (bps)	2	3	2	3	2	3
Total Incentive (bps)	2	3	2	3	2	3

Q. Please describe the Division's proposal for a Low-Income Discount PIM.

A. The low-income discount is an important mechanism for not only reducing the energy burden of this important customer group, but also for enabling more low-income customers to pay their bills thereby reducing the Company's arrearages. Mr. Colton addresses the Division's proposal for modifications to the Company's low-income discount.

We propose establishing a PIM to encourage National Grid to increase the number of low-income customers that are on the low-income, A60 discount. The metric for this PIM would the percentage of total low-income customers that are on the A60 discount. The baseline would be the average of the low-income discount participation percentage for the previous five years.[20]

The low-income discount PIM does not have any benefits that can be readily quantified. Therefore, we propose an incentive based upon the unquantified benefits of improving low-income customer affordability and reducing utility arrearages. The targets and incentives we propose for this PIM are provided in Table 18.

Table 18. Low-Income Discount PIM: Targets and Incentives

Low Income Discount	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (percentage point increase)	4	8	4	8	4	8
Incentive for Quantified Benefits (bps)	-	-	-	-	-	-
Incentive for Unquantified Benefits (bps)	2	3	2	3	2	3
Total Incentive (bps)	2	3	2	3	2	3

Q. Please describe the Division's proposal for a Data Access PIM.

A. In order to fully enable increasing amounts or DERs and increasing levels of third-party activities, it will be necessary to provide customers and third-parties with access to key system data. This includes data on customer electricity consumption patterns and data regarding the operation and the constraints on the distribution system.

[20] For example, the baseline for 2021 would be the average participation percentage for 2016-2020.

We propose establishing a PIM to encourage National Grid to develop customer and third-party data access plans. The target would be to submit to the Commission the first annual Customer and Third-Party Data Access plan by July 2019. This plan should be developed in coordination with the Division and other stakeholders, and should comply with the relevant data access recommendations in the RI PST Report.[21]

The Data Access PIM does not have any benefits that can be readily quantified. Therefore, we propose an incentive based upon the unquantified benefits of providing important foundational support for power sector transformation. The incentives we propose for this PIM are provided in Table 19.

Table 19. Data Access: Targets and Incentives

Data Access	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Target	Plan	-	-	-	-	-
Incentive for Quantified Benefits (bps)	-	-	-	-	-	-
Incentive for Unquantified Benefits (bps)	1	-	-	-	-	-
Total Incentive (bps)	1	-	-	-	-	-

Q. Please describe the Division's proposal for a Peak Demand Forecasting PIM.

A. As the roles of DERs, third-parties, and active customers expand over time, it will be increasingly important for National Grid to improve its practices for forecasting distribution peak demand. The Company's forecasts will need to incorporate better information regarding where, and what kind, of DERs are being installed and are expected to be installed on its system. In the absence of detailed estimates regarding reduced (or increased) demand from DERs, the Company will over-build (or under-build)

[21] The RI PST Report, pp. 49-53.

its distribution system, resulting in excess costs, insufficient reliability, or both. Information on the geographical location of new DERs will be necessary in order to fully forecast distribution constraints and optimize its distribution investments.

We propose establishing a PIM to encourage National Grid to improve and expand upon its current forecasting practices. The target would be to submit to the Commission by July 2019 a Peak Demand Forecasting Report. This report should be developed in coordination with the Division and other stakeholders, and should comply with the relevant forecasting recommendations in the RI PST Report.[22]

The Peak Demand Forecasting PIM does not have any benefits that can be readily quantified. Therefore, we propose an incentive based upon the unquantified benefits of providing important foundational support for power sector transformation. The targets and incentives we propose for this PIM are provided in Table 20.

Table 20. Peak Demand Forecasting: Targets and Incentives

Peak Demand Forecasting	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Target	Report	-	-	-	-	-
Incentive for Quantified Benefits (bps)	-	-	-	-	-	-
Incentive for Unquantified Benefits (bps)	1	-	-	-	-	-
Total Incentive (bps)	1	-	-	-	-	-

[22] The RI PST Report, pp. 48-49.

4.7. Process for Reviewing PIMs and Recovering Incentives

Q. Please describe how the Commission should review the PIMs approved in this docket.

A. We recommend that the Commission direct National Grid to submit annual Performance Incentive Mechanism Plans, to provide all the information needed to establish the PIMs that will commence in the following calendar year. The submission and review of the annual PIM Plans should be coordinated and contemporaneous with the annual Energy Efficiency and System Reliability and Procurement Plans. Both plans should be submitted by October 31 each year, and subsequently reviewed by the Commission to be implemented in the following year.

For the first PIM Plan, the Commission should direct National Grid to submit it by November 31, 2018, in order to allow time for preparation after the order in this docket is issued. That first PIM Plan should include updated PIM proposals based upon all the Commission's ultimate findings in this docket. It should include updated metrics, targets, baselines, and incentives using the methodologies and assumptions directed by the Commission. The incentives would be based on updated benefit-cost analyses, using the most recently available New England Avoided Energy Supply Cost study, and related findings by the Commission.

The Commission should open a docket to review and make findings on the first PIM Plan. Given the importance of the first PIM Plan, we recommend that the Commission allow for full stakeholder input to its review, including adjudicative hearings. The Commission should allow several months for review of this first PIM Plan, which means that the PIMs might not be approved by the Commission until March of

2019. The Company should nonetheless begin working to achieve the PIM targets in January of 2019, based on the direction provided by the Commission in the order in this docket.

Q. Please describe how the Company should report information related to the PIMs to the Commission.

A. We recommend that National Grid file with the Commission an annual Performance Report, which would include all relevant information on the metrics, targets, and incentives earned for the period covering the previous calendar year. This report should be filed in the third quarter of the year following the relevant performance year, in order to allow time to collect and verify the relevant information. The submission and review of the annual Performance Reports should be coordinated and contemporaneous with the annual Energy Efficiency and System Reliability and Procurement Plans.

The annual Performance Report should include information on every PIM that applies to National Grid, including the Service Quality PIMs, the Energy Efficiency PIMs, all the PIMs created in this rate case (Docket 4770), and any remaining SRP PIMs. The reports would include information on the metrics for the most recent five years, to the extent that the data is available, to provide an indication of performance trends over time. The reports would also include information on the deviations between targets and actual values.

National Grid should also file with the Commission streamlined versions of the annual Performance Report on a quarterly basis, similar to how the Company currently submits quarterly reports for its energy efficiency activities. The quarterly reports are useful for monitoring whether the Company is roughly on track to meet its targets, and to determine whether any mid-year corrections might be necessary.

Q. Please describe when and how the Company's rates would be adjusted to provide the Company with the PIM incentives.

A. Once an annual Performance Report has been approved by the Commission, the Company's rates should be adjusted to account for amount of incentives earned by the Company. The PIM incentive rate adjustments should occur once per year and should occur at the same time as the decoupling and energy efficiency rate adjustments, in order to streamline the regulatory process and minimize the number of times within the year that rates are adjusted.

4.8 The Mechanics of the Earnings Sharing Mechanism

Q. Please describe the earnings sharing mechanism that is currently in place.

A. Currently, the Company's earnings are subject to an earnings sharing mechanism, under which the Company must file annual reports calculating the Company's return on equity for the prior calendar year. This mechanism was established in Docket 4323. An earnings report is filed for both the electric and gas businesses separately and calculates the earned return on common equity (ROE) including and excluding any incentives earned under the energy efficiency program. If the Company's earned ROE is greater than the allowed ROE, the Company shares the over-earnings with ratepayers 50/50 until excess earnings reach 100 basis points over the allowed ROE. Any excess earnings in excess of 100 basis points over the allowed ROE is shared 75/25 in favor of ratepayers. Whether or not the energy efficiency incentive would be taken into account was not specified. However, since the current mechanism was put in place, the Company has not exceeded its allowed ROE, as measured by any of the filed reports in that Docket. For that reason, the question of the applicability of the energy efficiency was never addressed.

Q. What is the Division proposing in this case?

A. In this case, the Division recommends that an earnings sharing mechanism remain in place, measured against the allowed ROE established by the Commission in this Docket. However, the Division recommends some important changes to the mechanism applying to electric side of the business that will work in conjunction with the PIMs.

Q. Please explain how the earnings sharing mechanism would work.

A. Similar to today's mechanism, the Company would be required to file annual earnings reports for both electric and gas. The gas earnings report should contain the same information and operate the same as it is operating today, with the same sharing of excess earnings as designated in Docket 4323. However, for the electric earnings report, the reports should calculate the earnings with and without any PIMs awards from the prior calendar year in order to show the Commission the effect of the PIMs on the Company's performance. The operation of the electric earnings sharing mechanism would also be different. Specifically, to the extent the Company has earned over its allowed ROE, the Company would be able to retain 100% of all earnings up to 100 basis points over the allowed ROE. Once the excess earnings exceed 100 basis points, however, the amount of excess earnings above 100 basis points would be shared 75/25 in favor of ratepayers. All PIMs earned on the electric side of the business should be counted in the calculation of the overearnings, including the energy efficiency incentive and any new PIMs approved by the Commission. The earnings sharing mechanism will assure that the new PIMs programs, in conjunction with the existing energy efficiency incentive, will not result in excessive earnings. At the same time, since there is a sharing of any excess over 100 basis points, ratepayers are protected.

Q. Why are you recommending that 100% of the earnings be retained by the Company up to 100 basis points?

A. This is an important change from the current mechanism in light of the incentives the Division is proposing in this case. It is consistent with the recommendation to set the allowed ROE at the lower end of the cost of equity range. By achieving the PIMs targets, the Company has the opportunity to grow its earnings from the lower end of the range upward. However, by setting a sharing point after 100 basis points that triggers a 75/25 sharing with ratepayers, it provides an important and significant incentive to the Company, while at the same time protecting ratepayers from excessive earnings.

5. NATIONAL GRID'S PERFORMANCE INCENTIVE MECHANISM

5.1. National Grid's Proposal

Q. Why has the Company proposed PIMs?

A. National Grid notes that it has developed PIMs to advance Rhode Island's energy policy goals, provide new benefits to customers, and reward utility performance in delivering key programs.[23] The Company claims that the current regulatory framework "is not sufficient to drive innovative utility performance," and that new compensation

[23] PST Panel Direct Testimony, p. 81, lines 15-19.

mechanisms are needed to align utilities' "financial interests with broader policy goals and customer outcomes that expand beyond core performance obligations."[24]

Q. What type of PIMs has the Company proposed?

A. National Grid has proposed four types of PIMs: capital efficiency, system efficiency, DER, and network support service PIMs.

Q. What are the Company's proposed PIMs based on?

A. National Grid states that it considered the PIM recommendations in the Power Sector Transformation Report. The Company views the PIMs proposed in this docket as a "first step in a broader evolution of the regulatory framework," suggesting that the proposed PIMs could be modified or expanded over time.[25] National Grid also followed several principles in designing its PIMs, as described in Section 4.3

Q. Does National Grid already have PIMs in place today?

A. Yes. Since 1990 the Company has had a shareholder incentive mechanism for its energy efficiency programs. The energy efficiency PIM was developed through negotiations with the Company in the DSM Collaborative, and it has been modified several times in the past. National Grid also has a set of PIMs related to its service quality plans. The Company is also allowed to earn shareholder incentives for long-term renewable contracts, distributed generation contracts, and the Renewable Energy Growth program, as determined by legislation.

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[24] PST Panel Direct Testimony, p. 83, lines 9-14.
[25] PST Panel Direct Testimony, p. 84, lines 1-9.

Q. Does National Grid's proposal for new PIMs include any penalties for underperformance?

A. No. All of the PIMs proposed by the Company include only rewards for performance related to the relevant targets. National Grid notes that the reward-only PIMs are appropriate because they are related to new customer benefits, and they "reflect new areas of accountability for the Company that expand beyond its core obligations."[26]

Q. Please summarize the capital efficiency PIMs proposed by National Grid.

A. The Company has proposed two capital efficiency PIMs:

- The Complex Capital Projects Capital Cost Incentive. The Company is proposing to compare actual final capital costs to a baseline estimate of capital costs that were used to review and approve the project. Any savings relative to the baseline would be shared equally between customers and shareholders, and any costs above the baseline would be borne by the Company's shareholders.
- The Construction Costs per Mile Productivity Incentive. The Company has not fully developed this metric. National Grid plans to develop a metric based on the construction cost per mile for distribution projects. The Company notes that it will propose a baseline and targets for this PIM in its FY 2020 Electric ISR Plan filing.[27]

Q. Please summarize the System Efficiency PIMs proposed by National Grid.

A. National Grid's proposed System Efficiency PIMs are summarized in Table 21.[28]

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[26] PST Panel Direct Testimony, January 12, 2018, page 85, lines 4-9.
[27] PST Panel Direct Testimony, January 12, 2018, page 86, lines 10-14.
[28] PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 15 (Bates 18)

Table 21. Company's Proposed System Efficiency PIMs

PIM	Description	2019 Med Incentive (bps)	2019 Max Incentive (bps)
FCM Peak Demand Reduction	Reduce annual FCM peak hour demand (weather-normalized). Baseline is 2018 FCM peak.	12	18
Transmission Peak Demand Reduction	Reduce monthly transmission peak demands. Baseline is sum of 11-months of 2018 transmission peaks.	1.75	2.5
Off-Peak Charging Rebate Pilot	Pilot program to encourage customers to charge EVs during off-peak hours. Baseline is the assumed participation rates.	2.5	3.0
Total	**----------------------**	**16.25**	**23.5**

Q. Please provide additional details on the FCM Peak Demand Reduction PIM proposed by National Grid.

A. The purpose of the FCM Peak Demand Reduction PIM is to encourage the Company to reduce the annual forward capacity market (FCM) peak demand to reduce Narragansett Electric's share of annual FCM costs. The metric for this PIM will be the weather-normalized FCM peak demand. The baseline for this PIM is the actual weather-normalized FCM peak demand of the previous year, beginning with 2018. The Company's proposed MW targets are presented in Table 22.[29]

Table 22. The Company's Proposed FCM PIM Targets

FCM PIM	2019 Target (med)	2020 Target (med)	2021 Target (med)
Metric: Weather-normalized annual FCM peak capacity reduction (MW) relative to previous year.	29	26	26

[29] PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 15 (Bates 18)

These annual FCM targets include the savings that the Company expects to achieve through energy efficiency, distributed generation, volt-var optimization (VVO), and storage.[30] Consequently, the MW savings targets for the FCM PIM only represent additional savings of 5 to 6 MW each year.

Q. Please provide additional details on the Transmission Peak Demand Reduction PIM proposed by National Grid.

A. The purpose of the Transmission Peak Demand Reduction PIM is to encourage the Company to reduce monthly transmission peaks to reduce Narragansett Electric's share of monthly transmission costs. The metric for this PIM is the sum of monthly weather-normalized transmission peak demand. It is unclear whether the Company intends for these values represent the sum of 11 months of transmission peaks or 12 months of transmission peaks. In response to DIV 3-9 (e), the Company states that "to avoid double counting, the Company did not attribute any capacity savings from the month where the annual peak occurs to the Monthly Peak Demand Reduction metric." However, in response to DIV 8-14 (d), the Company states that its proposal for the Monthly Transmission Peak Demand metric is the "annual sum of 12 months peak demands, inclusive of the maximum month. These targets are intended to capture additional incremental effort by the Company to reduce peak demand outside of the annual peak month."

The Company proposes that the baseline for this PIM will be the sum of the actual weather-normalized transmission peak demands in the previous year. This means that the

[30] Attachment DIV 25-5.

Company's proposed MW savings targets in 2019 are relative to the transmission peak values in 2018, while the savings achieved in 2020 are relative to the transmission peak values in 2019. The Company's proposed MW targets and basis point incentives for this PIM for 2019 are presented in Table 23.[31]

Table 23. The Company's Proposed Transmission PIM Targets

Transmission Peak Demand Reduction PIM	2019 Target (med)	2020 Target (med)	2021 Target (med)
Metric: sum of monthly of transmission peak capacity savings (MW), year-over-year	29	26	26

Q. Please summarize the DER PIMs proposed by National Grid.

A. National Grid's proposed DER PIMs are summarized in Table 24.[32]

[31] PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 15 (Bates 18)

[32] PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 16-17 (Bates 19-20)

Table 24. The Company's Proposed DER PIMs

DER PIM	Description	Med Incentive (bps)	Max Incentive (bps)
DG Friendly Substations	The number of substations that have ground fault detection (3V0) installed and that are capable of readily installing DG where significant amounts of DG have been proposed	6	10
Demand Response: Residential	Measured by the number of residential customers participating in the Company's Connected Solutions program.	3	5
Demand Response: C&I	Measured by the contracted MWs in the Company's C&I demand response programs.	3	5
Electric Heat	Measured reductions in carbon in short tons per year.	1	2
Electric Vehicles	EV ownership, measured by EVs registered after commencement of program, in excess of projections based on Annual Energy Outlook 2017 forecast EV sales growth for New England.	2	3.5
Behind the Meter Storage	Measured by the annual MW growth in energy storage installed at customer locations behind a meter used to register electric load.	1	2
Company-Owned Storage	Measured by the installed MW of Company-owned in energy storage, inclusive of the ESS Program above, used to support peak load reduction and verified using interval metering.	1	2
Total	**----------------------**	**17**	**29.5**

Q. Please summarize the network support services PIMs proposed by National Grid.

A. National Grid's proposed network support services PIMs are summarized in Table 25.[33]

[33] PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 17-18 (Bates 20-21)

Table 25. The Company's Proposed Network Services PIMs

Network Support PIM	Description	Med Incentive (bps)	Max Incentive (bps)
AMF Customer Engagement and Deployment	Measured based on achievement of stated milestones with documentation evidencing achievement provided by the Company. Basis points vary by year.	1 to 2	1 to 2
VVO Pilot Delivery	Project in service; delivery of expected results of VVO deployment measured by a 1 percent reduction in energy consumption and peak demand from that expected from primary VVO optimization that would not include AMF technology of 3 percent	2	2
Interconnection Support: Time to ISA	The actual average time to provide executable Interconnection Service Agreements, measured from the date on which the Company receives the interconnection application to the date the ISAs are provided to customers for execution, during a calendar year, against total time allowed in the required time frames identified in the Company's Standards for Interconnecting Distributed Generation tariff, stated as a percentage.	4	6
Interconnection Support: Average Days to System Modification	The actual average time to complete system modifications, measured from the date ISAs are executed to the date on which system modifications are completed, during a calendar year, against total time allowed in the required time frames identified in the Company's Standards for Interconnecting Distributed Generation tariff, stated as a percentage.	4	6
Interconnection Support: Estimate versus Actual Costs	The difference, measured as a percentage, between the sum of the costs estimated by the Company for interconnecting DG, during a calendar year, and the sum of the actual costs paid by those customers for the interconnection of DG where interconnection was completed in the same calendar year.	4	6
Total	------------------	**15 to 16**	**21 to 22**

Q. Please summarize the total incentives that National Grid could potentially earn in 2019 from all its proposed PIMs.

A. These are summarized in Table 26.

Table 26. Incentives that National Grid Could Potentially Earn (bps)

Type of PIM	2019 (med)	2019 (max)	2020 (med)	2020 (max)	2021 (med)	2021 (med)
System Efficiency	16.25	23.25	16.25	23.25	16.25	23.25
Distributed Energy Resources	17.0	29.5	17.0	29.5	17.0	29.5
Network Support Services	16.0	22.0	15.0	21.0	15.0	21.0
Total	49.25	74.75	48.25	73.75	48.25	73.75

5.2. Critique of National Grid's Proposal

Q. Please describe your concerns with National Grid' proposed Capital Efficiency PIMs.

A. Our primary concern with these PIM is that they are not necessary. As described in the direct testimony of Mr. Woolf, the Division recommends that the Commission establish a multi-year rate plan. Under this proposal the Company would automatically have a financial incentive to reduce capital costs and improve productivity between rate cases. In fact, this is one of the primary reasons for establishing an MRP. In the event that this case does not yield an MRP, we offer alternative approaches for encouraging efficient use of capital costs and improved productivity, as described in the direct testimony of Mr. Woolf.

We are also concerned that these PIMs could place too much risk on the customers. The Company would determine the initial capital costs used to set the targets, and therefore has an incentive to overstate cost projections.

Q. Please describe your concerns with National Grid's proposed FCM Peak Demand Reduction PIM.

A. We have concerns regarding the baseline, targets, and incentives associated with National Grid's proposed FCM PIM. First, National Grid proposes to reduce peak demand on a year-over-year basis. These targets were developed in relation to a baseline forecast of peak demand, but converting them to year-over-year targets divorces them from the baseline, rendering it meaningless.[34] The use of a sound baseline in setting and measuring targets is critical, as it captures the effects of many other drivers of peak demand reductions. If these other factors are not accounted for in setting and measuring PIM targets, then the Company might be rewarded for peak demand reductions that are not a result of its actions (or not rewarded despite utility actions that successfully reduce FCM peak demand.)

Second, the Company did not propose targets that provide a sufficient degree of certainty that they will be achieved due to Company effort, rather than other factors. When a forecast is used as a baseline for a PIM, it is often appropriate to establish a "deadband" around the forecast. A deadband is a region around the target within which the Company would not earn a reward (or incur penalties). The concept of a deadband is often used to account for uncertainty regarding the target or to allow for some deviation from the target due to factors outside of utility control.[35] Setting PIM targets outside of a

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[34] A consequence of this would be that the same total rewards could be earned over the three year period for varying levels of cumulative peak demand reductions. Suppose, for example, that the Company increased peak demand in the first year artificially, followed by achieving "high" reductions the following two years, which would be easier to achieve. Because the PIM has no penalty for under-performance in year 1, the same rewards could be earned through this method, even though the cumulative reductions would be lower than if the Company had achieved the medium target each year.

[35] Synapse Energy Economics, *Utility Performance Incentive Mechanisms: A Handbook for Regulators.*

deadband helps to ensure that the utility is not provided incentives for outcomes that it is not responsible for.

The Company's FCM peak forecast, along with our proposed deadband and PIM targets are presented in Figure 2, in Section 4.4. The figure indicates that the Company's proposed FCM PIM targets for 2019 and 2020 fall within our estimate of a reasonable deadband, suggesting that the Company could be rewarded for FCM peak reductions that would have occurred in the absence of the PIM or the utility actions. In sum, the Company's proposal would result in PIM targets that have a reasonable likelihood of being achieved without any additional effort by the Company.

Q. Please describe your concerns with National Grid's proposed Transmission Peak Demand Reduction PIM.

A. We have concerns regarding the baseline, the targets, and the incentives associated with National Grid's proposed Transmission PIM. As described above, we do not agree with using the year-over-year reductions in demand as the metric for the transmission peak reduction targets. Performance should be measured relative to a forecast baseline. The use of a sound baseline in setting and measuring targets is critical, as it captures the effects of many other drivers of transmission peak demand reductions. If these other factors are not accounted for in setting and measuring PIM targets, then the Company might be rewarded for peak demand reductions that are not a result of its actions

This is the same problem described above for the FCM PIM. However, unlike the FCM peak demands, the Company does not have a forecast of monthly transmission peak demands.[36] In order to be able to properly evaluate the proposed Transmission PIM, we have prepared our own transmission peak forecast, using historical data provided by the Company.

Our analysis shows that the historical transmission peak demands have been trending downward, and this trend is likely to continue. If the transmission peak reduction targets are based on the 2018 historical peak demand, then the Company could be rewarded for peak reductions that would have occurred without the Transmission PIM and without utility actions.

As noted above, it is often appropriate to establish a "deadband" around the forecast within which there would be no reward or penalties for performance. Deadbands are useful for mitigating uncertainty regarding the target and to allow for some deviation from the target due to factors outside of utility control.[37] PIM targets should be designed to fall outside of such a deadband, to ensure that the utility is not provided incentives for outcomes that it is not responsible for.

The Company's historical transmission peak demand, along with our forecast, proposed deadband, and PIM targets are presented in Figure 3, in Section 4.4. As indicated in the figure, the Company's proposed Transmission PIM targets for 2019 and 2020 fall above our forecast and our estimate of a reasonable deadband, suggesting that the Company could be rewarded for transmission peak reductions that would have occurred in the absence of the PIM or the utility actions. In sum, the Company's proposal to use a historical year for the baseline, instead of a reasonable forecast, has resulted in

[36] Response to (4770) Division 25-14

[37] Synapse Energy Economics, *Utility Performance Incentive Mechanisms: A Handbook for Regulators.*

Transmission PIM targets that might be so easy to meet that they will not provide any benefits to customers.

In addition, we do not agree with the way that National Grid determined the magnitude of the incentive associated with the Transmission PIM. Because the Company does not have estimates for monthly demand reductions from other initiatives, the Company's proposal appears to allow it to earn financial incentives under this PIM as a result of the energy efficiency, distributed generation, and other PST initiatives that have their own PIMs. This would result in the Company earning PIM incentives twice; once for the Transmission PIM and once for the other PIMs that result in transmission peak reductions.

Q. Please describe your concerns with National Grid's proposed Off-Peak Charging Rebate Pilot PIM.

A. In general, we agree with the Company's goal of encouraging customers to charge their EVs during off-peak hours, and that this could be an important way to transition EV customers to TVR in the future. However, we do not think that participation in Off-Peak Charging Rebate Pilot is a very robust metric for this purpose. Customer participation in the rebate program does not necessarily mean that customers will change their charging patterns.

In addition, we are not convinced that the Company's proposed pilot is the best way to promote the cost-effective adoption of EVs.[38] We prefer an EV metric that is more

[38] Our concerns about the Company's proposed Electric Vehicle initiative are described in our testimony in Docket 4780.

closely tied with one of the primary objectives for promoting EVs: the reduction of greenhouse gases.

Q. Please describe your concerns with National Grid's proposed Distributed Energy Resource PIMs.

A. Our concerns with National Grid's proposed DER PIMs are summarized below:

- DG-Friendly Substation Transformer. It is our impression that National Grid should be installing ground fault detection (3VO) at substation transformers in a timely fashion as part of its core performance obligation. Installation of these technologies is now common practice for the Company, and National Grid does not require a PIM to encourage better or timelier performance in meeting its obligations.
- Demand Response: Residential. The number of customers participating in the program is not a good metric for demand response programs, because it does not directly reflect the outcome desired, which is the ability to reduce demand during peak hours. We prefer a metric that reflects the number of MW that the Company has contracted customers to provide during peak hours. In addition, we prefer that the magnitude of the incentive be based on a shared savings approach; which will encourage the Company to design and implement programs in the most cost-effective way, and will protect customers in the event that the demand response program net benefits are small or negative.
- Demand Response C&I. We prefer that the magnitude of the incentive be based on a shared savings approach; which will encourage the Company to design and implement programs in the most cost-effective way, and will protect customers in the event that the demand response program net benefits are small or negative.
- Electric Heat Initiative. We prefer that the magnitude of this incentive be based on a shared savings approach. This will encourage the Company to design and implement programs in the most cost-effective way, and will protect customers in the event that the initiative's net benefits are small or negative.

- Electric Vehicles. One of the primary policy goals for promoting EVs is to reduce greenhouse gas emissions. Therefore, we prefer a metric that is more directly tied to this policy goal.
- Behind-the Meter Storage. We are concerned that the Company's behind-the-meter storage program is not sufficiently defined at this time. Also, for the many customers that do not have time-varying rates, behind-the-meter storage is not likely to be economical. Even for those customers with TVR, the Company has not demonstrated that behind-the-meter storage will provide net benefits to customers. We prefer that the magnitude of any incentive be based on a shared savings approach; which will encourage the Company to design and implement a program in the most cost-effective way, and will protect customers in the event that the program net benefits are small or negative.
- Company-Owned Storage. We are concerned that the Company-Owned Storage PIM is not justified on economic grounds. The Company's BCA indicates that company-owned storage has a benefit-cost ratio of 0.45.[39] In addition, we prefer that the magnitude of any incentive be based on a shared savings approach; which will encourage the Company to design and implement a program that is cost-effective, and will protect customers in the event that the program net benefits are small or negative.

Q. Please describe your concerns with National Grid's proposed Network Support Services PIMs.

A. In general, we are concerned that all of the Company's Network Support Services PIMs are not justified because they are for activities that National Grid should undertake anyway. In particular:

- AMF Customer Engagement and Deployment. This PIM is premature, given that the Commission has not yet approved system-wide deployment of AMF.

[39] Schedule PST-1, Chapter 7, Energy Storage, page 6 of 9.

- VVO Pilot Delivery. The Company has clearly demonstrated that VVO will improve the efficiency with which the electricity grid is operated and provide significant net benefits to customers.[40] While VVO technologies might be described as relatively new, they fall within the Company's core performance obligations, and thus do not warrant a PIM. In addition, VVO technologies are not necessarily foundational to power sector transformation.
- Interconnection Support – Time to ISA. The Company already has a legislative requirement and performance standards to complete certain aspects of the interconnection process for distributed generation in a timely fashion.[41]
- Interconnection Support – Estimate Versus Actual Cost. Interconnecting distributed generation customers at a reasonable, low cost is already a part of the Company's core performance obligations, and thus does not warrant a PIM.

6. NEW GRID MODERNIZATION INVESTMENTS

6.1. National Grid's Proposal

Q. Please describe National Grid's proposal for new grid modernization investments.

A. The Company has submitted a request for approval of several projects intended to enable the adoption and interconnection of higher levels of DER. National Grid introduces these projects in Schedule PST – 1, Chapter 3 of its initial filing, and addresses them further in Section V.a in the PST Panel testimony in Docket 4780. The Company sometimes refers to these investments as "new grid modernization activities," and sometimes as "DER enabling investments." These investments cover a variety of distribution system

[40] Response to (4770) Division 3-20, Attachment DIV 3-20.

[41] See, RI Gen L § 39-26.3-3 (2012): Upon receipt of a completed application requesting a feasibility study and receipt of the applicable feasibility study fee, the electric distribution company shall provide a feasibility study to the applicant within thirty (30) days. Upon receipt of a completed application requesting an impact study and receipt of the applicable impact study fee, the electric distribution company shall provide an impact study within ninety (90) days.

upgrades, including those related to: a system data portal; feeder monitoring sensors; control center enhancements; operation data management; telecommunications; and cybersecurity.[42]

Q. Please explain why the Company's proposed new grid modernization investments are relevant to this rate case docket.

A. While National Grid's proposal for new grid modernization projects was included as part of Docket 4780, there are two categories of those projects that would impact the revenue requirements in this rate case docket. First, the Company proposes to move forward with a multi-jurisdictional deployment of its GIS Data Enhancement project and include some of the new grid modernization investments, ranging from $0.43 million it its revenue requirements for the 2019 rate year.[43] They also include a study to help design the AMF proposal, equal to $2 million in the 2019 rate year.[44] If the Commission is to allow recovery of the costs of these projects in the revenue requirements for rate year 2019, then it will need to do so in this rate case.

Q. The Company has requested that the costs for the new grid modernization projects be recovered separately from base rates through a PST Factor. Does this obviate the need for the Commission to consider the proposed new grid modernization projects in this rate case docket?

A. No. As described in Mr. Woolf's testimony, the Division recommends that the Commission reject the Company's proposal to recover new grid modernization costs, or

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[42] Testimony of the Power Sector Transformation Panel, January 12, 2018, p. 27.
[43] Response to (Docket 4770) Division 32-23.
[44] Response to (Docket 4770) Division 19-8, Attachment DIV 19-8-3, pp 1-2.

any costs related to power sector transformation, in a PST Factor. Therefore, if the Commission is to allow recovery of the costs of these projects in the revenue requirements for rate year 2019, then it will need to do so in this rate case.

6.2. Integration of Distribution System Planning and Review

Q. Please explain why the Division does not support the Company's proposal to recover new grid modernization costs separately from base rates in a PST Factor.

A. As described in the Direct Testimony of Mr. Woolf, the Division strongly recommends that the Commission direct the Company to better integrate the planning, review, and cost recovery of the various projects that, in one way or another, contribute to providing reliable, safe, clean, and affordable distribution services. This includes more integrated planning practices for conventional distribution, grid modernization, DER-enabling, and DER projects. It also includes more integrated regulatory review of these projects, through rate cases, ISR cases, energy efficiency and system reliability plans, and any other practices established as a result of the PST initiative in Docket 4770 and 4780. National Grid has also stated a preference for better integration of the regulatory review of its distribution system and DER-related projects.[45]

The Division is opposed to a PST Factor because it moves in exactly the opposite direction by creating a new category of projects that will be given different regulatory treatment than other projects. First, it is difficult to distinguish between conventional distribution projects, grid modernization projects, DER-enabling projects, and DER projects. Second, this fractured approach makes it difficult for the Division and the

[45] Testimony of the Power Sector Transformation Panel, January 12, 2018, pages 16 and 29-30.

Commission to evaluate the distribution business activities of the Company on a logical, integrated basis. Third, ability to recover all PST costs on a reconciling basis, while recovering conventional distribution costs in the context of rate cases, would shift cost risks to ratepayers with little or no risk to the Company. This would provide the Company with inconsistent regulatory and financial incentives for projects that should be compared directly with each other on an equivalent basis.

6.3. Recommendations

Q. What do you recommend regarding National Grid's proposal for new grid modernization investments?

A. We recommend that the Commission reject National Grid's request for a PST Factor, and direct the Company to submit requests for recovery of any type of distribution costs through either the rate case process or the ISR process. As described in the direct testimony of Mr. Woolf, rejecting the proposed PST Factor is one of the Division's top priorities in Dockets 4770 and 4780.

We also support Mr. Booth's recommendation that the Commission direct the Company to submit a grid modernization plan that considers all potential distribution system projects and investments in an integrate fashion. The Commission should also direct the Company to eliminate the unwarranted distinction between conventional, grid modernization, DER-enabling, and DER projects, for the purpose of regulatory review and cost recovery.

7. ADVANCED METERING FUNCTIONALITY

7.1. National Grid's Proposal

Q. Please explain why the Company's proposed AMF investments are relevant to docket 4770.

A. As part of Docket 4780, the Company has requested approval to perform additional design work during FY 2019 in order to "provide the necessary groundwork for implementation of its future AMF investments" that it will submit for further review and approval by December 1, 2018.[46] The cost of this design work was very roughly estimated by the Company to be $2,000,000, and would impact the revenue requirements at issue in the instant docket.[47]

Q. Is AMF an investment that should be investigated further?

A. Yes. In order for Rhode Island to achieve the outcomes recommended by stakeholders in Docket 4600, AMF investments will be necessary. For example, AMF enables the following outcomes: "outage protection, faster outage restoration, access to various pricing options that can save [customers] money, access to energy efficiency and renewable services tailored to [customers'] usage, and more efficient use of the distribution system that creates consumer savings."[48]

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[46] *Id,* page 37

[47] Direct Testimony of the Power Sector Transformation Panel, January 12, 2018, page 4 and response to Attachment DIV 19-8-3 (Docket 4770).

[48] Ibid., page 32.

Q. What analysis has the Company already performed with respect to AMF?

A. The Company has developed preliminary cost estimates associated with full deployment of advanced metering functionality in Rhode Island, and expects that the deployment will result in significant benefits to customers and system savings. These benefits include enhanced energy management capability, enablement of third party programs and offerings, enhanced volt-var optimization, avoided O&M costs, and storm outage management system improvements.[49]

The Company's initial benefit-cost analysis shows that the investment is expected to be cost-effective under six of eight scenarios. These scenarios are shown in the table below.

Rhode Island Only				
	Opt-In		**Opt-Out**	
	Low Savings	**High Savings**	**Low Savings**	**High Savings**
Net Benefits (NPV $Million)	-$55.23	$16.99	-$30.53	$68.90
Benefit-Cost Ratio	**0.79**	**1.07**	**0.88**	**1.27**
Rhode Island and New York Joint Implementation				
	Opt-In		**Opt-Out**	
	Low Savings	**High Savings**	**Low Savings**	**High Savings**
Net Benefits (NPV $Million)	$12.92	$85.14	$37.19	$137.05
Benefit-Cost Ratio	**1.07**	**1.44**	**1.19**	**1.72**

[49] *Id*, page 38

7.2. The AMF Study

Q. Is it appropriate to conduct additional analysis prior to submitting an application for a full roll-out of AMF?

A. Yes. It is appropriate for several reasons. First, the potential benefits associated with AMF are large, but the costs are also large. Because of this, a relatively small percentage error in either direction on the estimated costs and benefits could have large consequences with respect to impacts on customers. To reduce this risk, it is appropriate to thoroughly study the costs and benefits prior to implementation.

Second, the technology and business models associated with AMF are evolving quickly. To fully capture the potential benefits associated with AMF, the Company should study new and emerging approaches to AMF – approaches that would reduce costs, avoid technology obsolescence, and reduce the risk of stranded costs. In other words, we believe that additional study could enable the Company to employ innovative practices for AMF implementation beyond what is typically done in the industry, potentially providing much greater net benefits to customers and serving as a model nationally.

Q. What innovative approaches to AMF should the Company study?

A. As discussed in the Rhode Island Power Sector Transformation report,[50] the Company should study the potential for shared communication infrastructure and enabling access to

[50] Rhode Island Power Sector Transformation report, November 8, 2017, page 42.

third party providers. In addition, we recommend that the Company investigate procurement of AMF as a service, rather than through a capital investment.

Q. Please describe the potential benefits of shared communication infrastructure.

A. The communication infrastructure backbone is one of the most costly aspects of AMF deployment. By sharing or expanding upon that infrastructure through partnerships, significant customer savings could be achieved.

Q. Please describe the benefits of enabling access to third party providers.

A. The competitive market is rapidly expanding the number of value-added services that can be provided to customers based on an individual customer's usage information. With appropriate privacy and security protections, enabling access to meter data and capabilities can greatly expand the services provided to customers in Rhode Island. For example, through analysis of customer data, customers could be offered energy efficiency, demand response, or distributed generation products tailored to their usage profiles.

In addition, new services are emerging that disaggregate customer usage data to provide services such as predictive analytics and preventative maintenance (e.g., informing customers that their furnace is working harder than normal, so it may be time to replace the filter), or informing customers about happenings in their home (for example, that their kids are home or that their attic light is on).[51]

[51] Examples of such companies currently providing these services are Powerley and Whisker Labs.

Q. Please explain what you mean by the procurement of "AMF as a service."

A. In many industries, equipment manufacturers now provide equipment-as-a-service, rather than requiring customers to purchase the equipment through a large capital investment. A similar concept is being applied to the smart grid through "smart-grid-as-a-service"[52] or "metering-as-a-service" where a third party provider owns the equipment, fully manages the project, and provides operational support to utilities through a subscription service.[53] This approach is already common for software, but is becoming more common for hardware as well. For example, Leidos has provided this service to several municipalities and cooperatives nationwide.[54] A presentation by the Company includes the following

[52] Tom Damon and Josh Wepman, "Smart Grid as a Service: An Alternative Approach to Tackling Smart Grid Challenges," *Electric Energy T&D*, May 2011, http://electricenergyonline.com/show_article.php?mag=71&article=575.

[53] MeterSys, "Metering as a Service® (MaaS)," MeterSys Advanced Metering Solutions, 2018, https://metersys.com/metering-as-a-services-maas/.

[54] See, for example: Smart Grid Today, "Lansing, Mich, Hires Leidos to Deploy Smart Grid," *Smart Grid Today*, July 20, 2017, https://www.smartgridtoday.com/public/Lansing-Mich-hires-Leidos-to-deploy-smart-grid.cfm.

comparison of utility AMI deployment strategies:[55]

Comparison with Types of AMI Deployments

Features	Traditional Own/Operate	Software as a Service (Hosted)	Fully Managed Service
Contract Prime	Utility	Utility	Leidos
Project Management	Utility	Utility	Leidos
Meter Warranty	1 year	1 year	Full Term
Business Case Workshop	Internal or paid for with consultant - Extra	Utility conducted	Included
Business Process Change	Limited execution - OJBPC	Utility conducted - OJBPC	Leidos Provided
Advanced Analytics	Limited – via contractor or consultant – Extra	Limited – via contractor or consultant – Extra	Included
Operational Support	Internal – or via calls with separate vendors - Extra	Internal – or via calls with separate vendors.	End-to-End Proactive Support
Field Systems	Utility troubleshooting	Utility troubleshooting	Utility Hands and Eyes
SLAs	N/A	N/A	End-to-End Business SLAs
Price	\$\$\$\$+	\$\$ + \$\$	\$\$\$

Q. What has the Company proposed as part of its design work?

A. The Company states that the study will be used “to undertake the next phase of design, including further exploration of partnerships, stakeholder input, and other innovative program elements, and to undertake a procurement exercise.”[56] In particular, the Company states that it has “commenced an effort to explore the value of a state-wide communications system,” and has issued a Request for Information to identify qualified suppliers to receive an end-to-end “Request for Solution” and to gather market

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[55] Steven Root, “Best Practices on AMI Implementation and Operations for Improving Efficiency,” November 5, 2015, http://www.publicpower.com/pdf/ecc15/Steven_Root.pdf.

[56] *Id.*, Page 3 of 31.

intelligence. In addition, the Company proposes to explore additional functionalities including load disaggregation and gas demand response.[57]

Q. Please describe the work associated with conducting this design work.

A. The Company has not provided a detailed description for the study. Instead, the Company developed a very general estimate of the costs at the departmental function level for its New York affiliate[58] that lacked detail. From this New York estimate, the Company extrapolated a study cost that would apply to a combined New York/Rhode Island study.

Q. What is your assessment of the Company's AMF study proposal?

A. The decision of whether and how to pursue AMF should not be taken lightly. It is a very large investment with potentially large benefits. For this reason, the Company should explore deployment scenarios, technologies, and other options very carefully. However, the Company has not provided sufficient detail to justify spending $2 million on such a study in Rhode Island, particularly when it states that such a study would be similar to that undertaken by its New York affiliate.[59] Division witness Michael Ballaban addresses the cost of the study in his testimony, including what should be allowed in the revenue requirement.

[57] Response to (4770) Division 32-19.
[58] Response to (4770) Division 23-5
[59] Response to (4770) Division 23-5

7.3. Recommendations

Q. What do you recommend regarding the Company's AMF study?

A. The Company's analysis shows AMI to be very promising, and it is clear that further study is warranted to develop the best approach for implementing AFM. However, such a study should be designed to provide additional value beyond the exploration that the Company is undertaking in New York. For this reason, we recommend that the Commission direct the Company to work with the Division to develop a study plan that provides significant additional information to the New York study. Further, the Company should be required to periodically meet with the Division to discuss the study findings and file a report with the Commission at the conclusion of the process. Following submittal of the AMI study, the Division recommends that the Commission open a docket to examine the study with stakeholders and to design a phased approach to application of time varying rates consistent with the principles of Docket 4600.

8. BENEFIT-COST ANALYSES

8.1. The Role of Benefit-Cost Analyses

Q. Please explain why benefit-cost analyses relevant in this rate case.

A. As described in Section 3, the Commission should address PIMs in this rate case docket because of the important inter-relationship between PIMs and the authorized ROE. Benefit-cost analyses are a critical element in designing PIMs, because they can help shed light on the potential net benefits of PIM activities, and thereby inform decisions regarding the magnitude of PIM incentives. Ideally, PIM incentives should be set at a level that will result in net benefits to customers.

Q. Please provide an overview of the role of benefit-cost analysis (BCA) in Rhode Island.

A. The role of cost-effectiveness (and thus BCAs) was recently addressed in Docket 4600. In April 2017, the Docket 4600 stakeholder working group submitted a report to the Commission providing recommendations for a new cost-effectiveness test, among other things.[60] The proposed Rhode Island Benefit-Cost Framework built off the cost-effectiveness test that has been used historically for energy efficiency resources, and included a broader range of costs and benefits to better reflect power sector transformation and state energy policy goals.

In October 2017, the Commission issued a Guidance Document that provided direction on how to address the issues raised in Docket 4600, and accepted the proposed RI Benefit-Cost Framework as the appropriate cost-effectiveness methodology.[61]

Q. What does the Commission's Guidance Document say about the role of BCAs?

A. The Guidance Document is clear that the RI Benefit-Cost Framework should play a central role in evaluating a wide range of utility proposals. Specifically, the Guidance Document states that:

> in any case that proposes new programs or capital investment that will affect National Grid's electric distribution rates, the impact of any increased ratepayer recovery should also reference the goals, rate design principles, and Benefit-Cost Framework. National Grid should apply the Benefit-Cost Framework to changes

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[60] Docket 4600 Stakeholder Working Group, Report to the Rhode Island Public Utilities Commission, April 5, 2017.

[61] Rhode Island Public Utilities Commission, Docket 4600, *Guidance on Goals, Principles, and Values for Matters Involving the Narragansett Electric Company*, October 27, 2017.

> in its cost of service for the primary purpose of complying with State policy or to expand a current program.[62]

Q. What does the Commission's Guidance Document say about using quantitative and qualitative data in the RI Benefit-Cost Framework?

A. The Guidance Document acknowledges that there is still significant work remaining to identify and quantify some of the impacts in the new framework. It clarifies that:

> Where the costs and benefits can be quantified, the proponent should provide such information and the basis for the conclusion reached. Where quantification is not possible or not practical, the proponent should so explain. Regardless of whether the quantification can be fully completed, a qualitative analysis should be included.[63]

Q. Is the Benefit-Cost Framework the only factor that should be used to evaluate proposals for new investments and new projects?

A. No. The Guidance Document states that:

> the Benefit-Cost Framework will not be the exclusive measure of whether a specific proposal should be approved. For example, there may be outside factors that need to be considered by the PUC regardless of whether a specific proposal is determined to be cost-effective or not. This may include statutory mandates or other qualitative considerations.[64]

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[62] Guidance Document, p. 6.
[63] Guidance Document, p. 6.
[64] Guidance Document, p. 7.

8.2. National Grid's Benefit-Cost Analyses

Q. Please provide an overview of the Company's BCA methodology.

A. National Grid applied two different approaches to evaluating costs and benefits. For the grid-side investments that are made to enable DER (i.e., those described in Chapter 3 of their PST filing), the Company used a best-fit/least-cost assessment methodology. For the investments in DER (i.e., those described in Chapters 4 through 7 of their PST filing) the Company applied a Rhode Island specific cost-effectiveness methodology.

Q. Please describe the best-fit/least-cost methodology used by the Company for DER-enabling[65] investments.

A. The Company refers to a recent US Department of Energy "Decision Guide" (DOE Report) as the source of that methodology. That report presents many different considerations for the best way to implement advanced distribution system technologies, including DERs.[66] With regard to cost-effectiveness considerations, the DOE Report describes advanced distribution system technologies as belonging to four categories: (a) traditional utility infrastructure investments; (b) DER-enabling investments; (c) DER-integration investments; and (d) self-support or direct-charge investments (i.e., those paid for by customers or third-parties). The DOE Report recommends that traditional and DER-enabling investments be subject to a best-fit/least-cost analysis or a traditional

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65 We prefer not using the categories and terms "DER-enabling" and DER-integration," because the categories are not well-defined and the distinctions are difficult to make. We use these terms in this testimony in order to be consistent with the Company's terminology.

66 The US Department of Energy, Modern Distribution Guide, Volume III, June 2017, Section 3.4.1.

utility benefit-cost analysis, and that DER-integration investments be subject to a societal benefit-cost analysis.[67]

In this Docket, the Company notes that it used the best-fit/least cost method "to evaluate proposed grid-side investments to enable DER using a conceptual cost estimate and an expectation that it will utilize a competitive procurement process as part of the deployment."[68]

Q. Do you agree with the Company's use of the best-fit/least-cost methodology for DER-enabling investments?

A. No. First, the Division is concerned about the way that the Company evaluated and proposed the DER-enabling investments in the absence of a more comprehensive, long-term grid modernization plan. This concern is addressed in more detail by Mr. Booth.

Second, the best-fit/least-cost approach used by the Company does not include any quantitative assessment of the potential benefits of the proposed investments. National Grid does not provide any benefit-cost analysis for these investments; it only provides a narrative description of what the investments will do and why they are needed.

We note that the DOE Report is clear that it may be appropriate to apply benefit-cost analyses to DER-enabling projects. It states that utilities could use best-fit/least-cost methodologies <u>or</u> traditional utility cost-benefit analyses.[69] National Grid has chosen not to use a traditional utility BCA. Further, there is nothing in the DOE Report to suggest that the Company cannot or should not use a different type of BCA, such as the RI

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[67] The US Department of Energy, Modern Distribution Guide, Volume III, June 2017, Section 3.4.1.

[68] PST Panel Direct Testimony, p. 25, lines 14-17.

[69] DOE Report, p. 39 and p. 40.

Benefit-Cost Framework, if so directed by the Commission. National Grid has chosen not to.

Q. Do you think that National Grid should use some form of BCA to justify its proposed DER- enabling investments in this docket?

A. Yes. The DER-enabling projects that the Company proposes in this docket include a total of $17.3 million over the three-year period from FY2018 – FY2020.[70] This is significantly larger than any other PST initiative in this docket (with the exception of the AMF proposal that the Company is not asking for approval of in this docket) and thus warrants more justification than the narrative that National Grid has provided.

Q. Does the fact that the Company is asking for a form of pre-approval of its PST investments affect the importance of using a BCA to justify its proposed grid-enabling investments?

A. Yes. The Company is essentially asking the Commission for pre-approval of its PST investments.[71] As a general matter, any request for pre-approval of a project should be supported with a comprehensive justification for the project, including a demonstration that the project is cost-effective and will result in net benefits to customers. In the absence of such a justification, the Commission should not pre-approve a project. The Company has not provided such a justification for the DER-enabling projects in this docket.

[70] Response to (4770) Division 19-8-3

[71] PST Panel Direct Testimony, p. 96, lines 1-4. Schedule PST- 1, Chapter 10, page 1.

It is important to note that this does not mean that the Company should not undertake those DER-enabling projects. It means only that the Commission should not pre-approve them without sufficient justification. If the Company believes that the DER-enabling projects will result in net benefits to customers, then it should undertake those investments and seek recovery of them in the next rate case.

Q. Are there other reasons why the Company should apply a BCA to the DER-enabling investments?

A. Yes. The Company's proposal to categorize DER-enabling projects differently from traditional distribution system projects and from DER-integrating investments creates several problems. It is often difficult to draw a clear distinction between conventional and DER-related projects, as described in more detail in Mr. Booth's direct testimony. It is also difficult to draw a clear distinction between DER-enabling and DER-integrating technologies. Creating different standards of analysis and review for different categories that are hard to define can lead to some projects being improperly categorized and thus improperly treated.

In addition, the Company's proposal means that traditional projects, DER-enabling projects, DER-integration projects are subject to different standards of review. Traditional projects would be subject to the standard of review applied in the existing rate case and ISR processes, while DER-enabling projects are subject to a best-fit/least cost standard, and DER-integration projects are subject to a standard based on the RI Benefit-Cost Framework. This could result in some projects being inappropriately accepted or rejected simply because they are subject to inconsistent standards. This would clearly be inconsistent with the Commission's directives in Docket 4600 and state energy policy goals in general.

As described in the direct testimony of Mr. Woolf, National Grid should be seeking ways to better integrate the planning of all types of resources, including EE, SRP, ISR, DER-enabling, and DER-integrating resources. The Company's proposal to treat DER-enabling and DER-integrating resources different goes directly against this key goal.

Q. Please describe the cost-effectiveness methodology used by the Company for DER-integrating investments.

A. The Company's cost-effectiveness methodology was designed to reflect the RI Benefit-Cost Framework approved by the Commission in its Guidance Document. Some of the costs and benefits are not yet sufficiently developed to be used in a quantitative fashion, so the Company simply addressed them qualitatively. The Company also vetted some of the inputs and value drivers with comparable exercises that it has undertaking for its Massachusetts and New York affiliates. The Company used assumptions and methodologies that are used to evaluate the EE programs, including all applicable avoided costs from the 2015 New England Avoided Energy Supply Costs report.[72]

[72] PST Panel Direct Testimony, pp.25-26.

8.3. Critique of National Grid's Benefit-Cost Analysis

Q. Do you agree with the overall approach National Grid used for its BCAs?

A. For those projects where it applied a BCA, the Company used the RI Benefit-Cost Framework approved by the Commission in the 4600 Guidance Document. This is clearly the appropriate framework to use in this context. In addition, the Company appropriately included a discussion of the qualitative benefits for each project, as required in the 4600 Guidance Document.

However, we have concerns with three of the inputs that the Company used in its BCAs. First, National Grid does not include any benefits associated with avoided distribution costs in its BCAs. Second, it appears as though the Company used outdated avoided FCM capacity costs in its BCA. Third, the Company used a discount rate based on its weighted average cost of capital, rather than a societal discount rate that would be more appropriate with the RI Benefit-Cost Framework.

Q. Please elaborate on your concern that National Grid does not include any benefits associated with avoided distribution costs.

A. In all of its BCAs, National Grid assumes that there will be no avoided distribution system costs. This is presumably because the Company did not have estimates of avoided distribution costs that it deemed sufficiently robust. In addition, avoided distribution costs can vary significantly by geographic location, creating another challenge in identifying reasonable assumptions for a BCA.

We are sympathetic to the limitations of current estimates of avoided distribution costs. However, assuming that DERs will provide no value in the form of avoided distribution costs is overly conservative. Distribution system benefits can be significant, particularly for some types of DERs, such as demand response or storage, which could be specifically designed to defer or avoid distribution projects. This assumption by National Grid will result in understating the benefits of the projects analyzed in the BCAs.

Q. Please elaborate on your concern that National Grid may have used outdated avoided FCM costs.

A. It is not clear what source National Grid used to determine avoided FCM capacity costs. In some instances, the Company refers to the 2015 AESC Report as the source of avoided cost assumptions for its BCAs.[73] In other instances, the Company refers to the AESC 2015 Update,[74] which was performed to reflect significant changes that had occurred in the New England wholesale electricity markets after the original report was conducted.[75] The distinction is very important because the avoided costs in the AESC 2015 Update are significantly lower than in the 2015 AESC Report.

Our review of the Company's assumptions suggests that the values used were those from the 2015 AESC Report. The Company's avoided FCM assumptions[76] are considerably higher than those included in the AESC 2015 Update.[77] If it is true that National Grid used the original 2015 AESC values, then its BCAs will overstate the benefits of the projects analyzed in the BCAs.

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[73] Schedule PST – 1, Chapter 2, p. 5, footnote 5.

[74] Docket 4770 Response to Division 25-6, Attachment DIV 25-6, p. 1.

[75] Tabors, Caramanis, Rudkevich, *AESC 2015 Update Results and Assumptions*, memo to the AESC Update Client Group, December 2016.

[76] Response to (4770) Division 25-6, Attachment DIV 25-6, p. 1.

[77] As reported in the AESC 2015 Update, Appendix B, p 1 of 2.

Q. Why do you believe that a societal discount rate should be used when applying the RI Benefit-Cost Framework?

A. A societal discount rate is most consistent with the RI Cost-Benefit Framework. The Framework includes several impacts that are societal in nature, such as environmental, job and economic development, low-income, and public health impacts. The RI framework essentially represents a societal perspective, which warrants using a discount rate that also reflects a societal perspective.

In addition, the Commission's Guidance Document in 4600 emphasizes the importance of long-term objectives and policy goals. The Guidance Document begins with a list of stated electric industry goals that were approved by the Commission. The first goal is to provide "reliable, safe, clean, and affordable energy to Rhode Island customers over the *long term*" (emphasis added).[78] The next two goals refer to addressing climate change and other environmental challenges, and promoting jobs and economic development; which also suggest a preference for long-term objectives and policy goals. As noted below, a societal discount rate places greater emphasis on long-term impacts, relative to a discount rate based on a utility WACC.

Further, using a utility WACC for a discount rate is not consistent with the goals of the Company's benefit-cost analysis in general.[79] A utility WACC represents the time preference of utility investors, primarily based on the cost of capital and the risks to those investors. A utility WACC would be appropriate for the purposes of maximizing value to

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[78] Rhode Island Public Utilities Commission, Docket 4600 Guidance Document, page 3.

[79] For additional discussion of this point, see: National Efficiency Screening Project, *the National Standard Practice Manual*, Chapter 9, May 2017.

utility investors, but this is not the purpose of the BCA. The purpose of the BCA is to identify the optimal mix of resources that will lead to "reliable, safe, clean, and affordable energy to Rhode Island customers over the long-term."[80] A societal discount rate is much more consistent with this purpose.

Finally, a societal discount rate is consistent with the discount rate that has been used for EE cost-effectiveness analysis for many years. In that context, National Grid uses a low-risk discount rate based on US Government Treasury Bills. This rate tends to be much lower than the utility WACC, and is sometimes used to represent a societal discount rate.

Q. How does a societal discount rate compare with a utility's WACC?

A. A societal discount rate is typically much lower than a utility's WACC. There is a range of views on what a societal discount rate should be, and the specific value of a societal discount rate should depend upon the impacts and the analysis it is applied to. Some analysts argue that a societal discount rate for valuing environmental impacts should be negative (in real terms). Others use societal discount rates on the order of one, two, or three percent (in real terms).[81] This entire range of societal discount rates is lower than the Company's WACC which is 7.5 percent in nominal terms, and 4.8 percent in real terms.

[80] Rhode Island Public Utilities Commission, Docket 4600 Guidance Document, page 3.
[81] National Standard Practice Manual, page 75.

Q. In general, how does using a societal discount rate affect the results of the cost-effectiveness analyses?

A. A lower discount rate will give greater weight to long-term costs and benefits than to short-term impacts as compared to a higher discount rate. In most cases, the PST initiatives require capital costs to be incurred in the early years while the benefits are experienced over a longer period of time. Consequently, a lower discount rate will typically indicate increased benefits, increased net benefits, and a higher benefit-cost ratio as compared to a higher discount rate like the WACC.

Q. Please provide an example of how the lower societal discount rate will affect the BCA results.

A. As one example, we used different discount rates for the Company's BCA for advanced metering infrastructure, in the case where the AMF costs are shared with New York, and in the Opt-Out Low Participation Scenario. Using the discount rate equal to the Company's WACC (4.8 percent in real terms) results in a benefit-cost ratio is 1.19; using a societal discount rate of two percent (in real terms), results in a benefit-cost ratio of 1.34; and using the current energy efficiency BCA discount rate of roughly 0.3 percent (in real terms) results in a benefit-cost ratio of 1.44.

8.4. Recommendations

Q. What do you recommend regarding the Company's use of the best-fit/least cost methodology to assess DER-enabling projects?

A. We recommend that the Commission reject the Company's proposal to evaluate any PST related projects, or any projects for which it is seeking pre-approval, with the best-fit/least cost methodology. This methodology is inconsistent with the Docket 4600 Guidance Document; is inconsistent with the overall goal of integrating the planning, review, and approval of all types of distribution system investment; and does not provide sufficient justification for the Commission to pre-approve projects.

Q. Which discount rate do you recommend be used for benefit-cost analyses in this docket?

A. We recommend that the Commission determine that a societal discount rate is the most appropriate rate to use when applying the Rhode Island Benefit-Cost Framework, and that the Commission direct the Company and other analysts to use a societal discount rate for all future applications of that framework. For the purposes of this rate case docket, we recommend that the Commission recognize that the Company's BCA results likely understate project benefits because the Company's discount rate is too high.

Q. What do you recommend regarding the benefits that the Company did not include in its benefit-cost analyses?

A. We recommend that the Commission recognize that the Company's BCA results likely understate project benefits because they do not include the benefits of avoiding distribution system costs. Further, the extent of any understatement will likely vary by PST initiative, such that one may not be able to directly compare the BCAs across initiatives.

Q. What do you recommend regarding the outdated avoided costs that the Company appears to be using?

A. We recommend that the Commission recognize that the Company's BCA results likely overstate project benefits, particularly avoided FCM capacity costs, because they appear to use outdated avoided cost assumptions that are higher than more recent assumptions.

Q. You have identified several significant problems with the Company's BCAs, two of which understate benefits, and one of which overstates benefits. Are you concerned that these problems will lead to the Commission approving uneconomic outcomes in this docket?

A. According to National Grid's proposal, all the PST initiatives that National Grid is proposing in this docket will be subject to further review by the Commission prior to them being undertaken by the Company. These PST initiatives will be included in the annual PST Plans that will be filed with the Commission. The first Plan will be filed by December 1, 2018, to investigate the potential PST initiatives for FY 2020.[82] At that time, the Company should file updated BCAs for each PST initiative that it seeks approval for, with improved methodologies and inputs using the Commission directives from this docket.

The Division has a different proposal for the review and approval of PST initiatives, as described in the direct testimony of Mr. Woolf. The Division recommends that, in the absence of a multi-year rate plan over the next three years, the Company

[82] PST Panel Direct Testimony, p. 5, lines 4-7.

should plan for and undertake PST initiatives that it expects to be cost-effective and to provide net benefits to customers without specific pre-approval from the Commission.

Consequently, under either the Division's or the Company's PST review proposal, the BCA results presented in this docket will not be the final BCA results used to make decisions on future PST initiatives.

Q. Does this conclude your direct testimony?

A. Yes, it does.

AFFIDAVIT OF TIM WOOLF

Tim Woolf, does hereby depose and say as follows:

I, Tim Woolf, on behalf of the Rhode Island Division of Public Utilities and Carriers, certify that testimony that bears my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the penalties of perjury this the 6th day of April, 2018.

Tim Woolf
Tim Woolf (Apr 5, 2018)
____

Tim Woolf

AFFIDAVIT OF MELISSA WHITED

Melissa Whited, does hereby depose and say as follows:

I, Melissa Whited, on behalf of the Rhode Island Division of Public Utilities and Carriers, certify that testimony that bears my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the penalties of perjury this the 6th day of April, 2018.

M. Whited

Melissa Whited

Tim Woolf, Vice President

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 2011 – present.

Provides expert consulting on the economic, regulatory, consumer, environmental, and public policy implications of the electricity and gas industries. The primary focus of work includes technical and economic analyses, electric power system planning, climate change strategies, energy efficiency programs and policies, renewable resources and related policies, power plant performance and economics, air quality, and many related aspects of consumer and environmental protection.

Massachusetts Department of Public Utilities, Boston, MA. *Commissioner*, 2007 – 2011.

Oversaw a significant expansion of clean energy policies as a consequence of the Massachusetts Green Communities Act, including an aggressive expansion of ratepayer-funded energy efficiency programs; the implementation of decoupled rates for electric and gas companies; an update of the DPU energy efficiency guidelines; the promulgation of net metering regulations; review of smart grid pilot programs; and review of long-term contracts for renewable power. Oversaw six rate case proceedings for Massachusetts electric and gas companies. Played an influential role in the development of price responsive demand proposals for the New England wholesale energy market. Served as President of the New England Conference of Public Utility Commissioners from 2009-2010. Served as board member on the Energy Facilities Siting Board from 2007-2010. Served as co-chair of the Steering Committee for the Northeast Energy Efficiency Partnership's Regional Evaluation, Measurement and Verification Forum.

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 1997 – 2007.

Tellus Institute, Boston, MA. *Senior Scientist, Manager of Electricity Program*, 1992 – 1997.

Association for the Conservation of Energy, London, England. *Research Director*, 1991 – 1992.

Massachusetts Department of Public Utilities, Boston, MA. *Staff Economist*, 1989 – 1990.

Massachusetts Office of Energy Resources, Boston, MA. *Policy Analyst*, 1987 – 1989.

Energy Systems Research Group, Boston, MA. *Research Associate*, 1983 – 1987.

Union of Concerned Scientists, Cambridge, MA. *Energy Analyst*, 1982-1983.

EDUCATION

Boston University, Boston, MA
Master of Business Administration, 1993

London School of Economics, London, England
Diploma, Economics, 1991

Tufts University, Medford, MA
Bachelor of Science in Mechanical Engineering, 1982

Tufts University, Medford, MA
Bachelor of Arts in English, 1982

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TESTIMONY

Rhode Island Public Utilities Commission (Docket No. 4783): Direct testimony of Tim Woolf and Melissa Whited regarding National Grid's Advanced Metering Functionality Pilot. On behalf of the Rhode Island Division of Public Utilities and Carriers. February 22, 2018.

New York Public Service Commission (Case 17-E-0459): Direct testimony of Tim Woolf regarding Energy Efficiency Earnings Adjustment Mechanisms proposed by Central Hudson Gas & Electric Company. On behalf of Natural Resources Defense Council. November 21, 2017.

New York Public Service Commission (Case 17-E-0238): Direct and rebuttal testimony of Tim Woolf and Melissa Whited regarding Earnings Adjustment Mechanisms proposed by National Grid. On behalf of Advanced Energy Economy Institute. August 25 and September 15, 2017.

Utah Public Service Commission (Docket No. 14-035-114): Direct and rebuttal testimony of Tim Woolf regarding the Pacificorp's analysis of the benefits and costs associated with distributed generation resources. On behalf of Utah Clean Energy. June 8, 2017 and July 25, 2017.

Massachusetts Department of Public Utilities (D.P.U. 17-05): Direct and surrebuttal testimony of Tim Woolf and Melissa Whited regarding performance-based regulation, the monthly minimum reliability contribution, storage pilots, and rate design in Eversource's petition for approval of rate increases and a performance-based ratemaking mechanism. On behalf of Sunrun and the Energy Freedom Coalition of America, LLC. April 28, 2017 and May 26, 2017.

Massachusetts Department of Public Utilities (D.P.U. 15-120, D.P.U. 15-121, D.P.U. 15-122/15-123): Direct testimony of Tim Woolf and Ariel Horowitz, PhD, regarding the petitions by National Grid, Unitil, NSTAR, and Eversource Energy for approval of their grid modernization plans. On behalf of Conservation Law Foundation. March 10, 2017.

Massachusetts Department of Public (D.P.U. 16-169): Direct testimony of Tim Woolf and Erin Malone regarding Nation Grid's petition for ruling regarding the provision of gas energy efficiency services. On behalf of the Cape Light Compact. November 2, 2016.

New Jersey Board of Public Utilities (Docket No. ER16060524): Direct testimony regarding Rockland Electric Company's proposed advanced metering program. On behalf of the New Jersey Division of Rate Counsel. September 9, 2016.

Colorado Public Utilities Commission (Proceeding No. 16AL-0048E): Answer testimony regarding Public Service Company of Colorado's rate design proposal. On behalf of Energy Outreach Colorado. June 6, 2016.

Georgia Public Service Commission (Docket No. 40161 and Docket No. 40162): Direct testimony regarding the demand-side management programs proposed by Georgia Power Company in its Certification, Decertification, and Amended Demand-Side Management Plan and its 2016 Integrated Resource Plan. On behalf of Sierra Club. May 3, 2016.

Massachusetts Department of Public Utilities (Docket No. 15-155): Joint direct and rebuttal testimony with M. Whited regarding National Grid's rate design proposal. On behalf of Energy Freedom Coalition of America, LLC. March 18, 2016 and April 28, 2016.

Maine Public Utilities Commission (Docket No. 2015-00175): Direct testimony on Efficiency Maine Trust's petition for approval of the Triennial Plan for Fiscal Years 2017-2019. On behalf of the Natural Resources Council of Maine and the Conservation Law Foundation. February 17, 2016.

Nevada Public Utilities Commission (Docket Nos. 15-07041 and 15-07042): Direct testimony on NV Energy's application for approval of a cost of service study and net metering tariffs. On behalf of The Alliance for Solar Choice. October 27, 2015.

New Jersey Board of Public Utilities (Docket No. ER14030250): Direct testimony on Rockland Electric Company's petition for investments in advanced metering infrastructure. On behalf of the New Jersey Division of Rate Counsel. September 4, 2015.

Utah Public Service Commission (Docket No. 14-035-114): Direct, rebuttal, and surrebuttal testimony on the benefit-cost framework for net energy metering. On behalf of Utah Clean Energy, the Alliance for Solar Choice, and Sierra Club. July 30, 2015, September 9, 2015, and September 29, 2015.

Nova Scotia Utility and Review Board (Matter No. M06733): Direct testimony on EfficiencyOne's 2016-2018 demand-side management plan. On behalf of the Nova Scotia Utility and Review Board. June 2, 2015.

Missouri Public Service Commission (Case No. ER-2014-0370): Direct and surrebuttal testimony on the topic of Kansas City Power and Light's rate design proposal. On behalf of Sierra Club. April 16, 2015 and June 5, 2015.

Missouri Public Service Commission (File No. EO-2015-0055): Rebuttal and surrebuttal testimony on the topic of Ameren Missouri's 2016-2018 Energy Efficiency Plan. On behalf of Sierra Club. March 20, 2015 and April 27, 2015.

Florida Public Service Commission (Dockets No. 130199-EI et al.): Direct testimony on the topic of setting goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems. On behalf of the Sierra Club. May 19, 2014.

Massachusetts Department of Public Utilities (Docket No. DPU 14-86): Direct and rebuttal Testimony regarding the cost of compliance with the Global Warming Solution Act. On behalf of the Massachusetts Department of Energy Resources and the Department of Environmental Protection. May 16, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): Direct testimony regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan. On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

Maine Public Utilities Commission (Docket No. 2013-168): Direct and surrebuttal testimony regarding policy issues raised by Central Maine Power's 2014 Alternative Rate Plan, including recovery of capital costs, a Revenue Index Mechanism proposal, and decoupling. On behalf of the Maine Public Advocate Office. December 12, 2013 and March 21, 2014.

Colorado Public Utilities Commission (Docket No. 13A-0686EG): Answer and surrebuttal testimony regarding Public Service Company of Colorado's proposed energy savings goals. On behalf of the Sierra Club. October 16, 2013 and January 21, 2014.

Kentucky Public Service Commission (Case No. 2012-00578): Direct testimony regarding Kentucky Power Company's economic analysis of the Mitchell Generating Station purchase. On behalf of the Sierra Club. April 1, 2013.

Nova Scotia Utility and Review Board (Matter No. M04819): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2013 – 2015. On behalf of the Counsel to Nova Scotia Utility and Review Board. May 22, 2012.

Missouri Office of Public Counsel (Docket No. EO-2011-0271): Rebuttal testimony regarding IRP rule compliance. On behalf of the Missouri Office of the Public Counsel. October 28, 2011.

Nova Scotia Utility and Review Board (Matter No. M03669): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2012. On behalf of the Counsel to Nova Scotia Utility and Review Board. April 8, 2011.

Rhode Island Public Utilities Commission (Docket No. 3790): Direct testimony regarding National Grid's Gas Energy Efficiency Programs. On behalf of the Division of Public Utilities and Carriers. April 2, 2007.

North Carolina Utilities Commission (Docket E-100, Sub 110): Filed comments with Anna Sommer regarding the Potential for Energy Efficiency Resources to Meet the Demand for Electricity in North Carolina. Synapse Energy Economics on behalf of the Southern Alliance for Clean Energy. February 2007.

Rhode Island Public Utilities Commission (Docket No. 3765): Direct and Surrebuttal testimony regarding National Grid's Renewable Energy Standard Procurement Plan. On behalf of the Division of Public Utilities and Carriers. January 17, 2007 and February 20, 2007.

Minnesota Public Utilities Commission (Docket Nos. CN-05-619 and TR-05-1275): Direct testimony regarding the potential for energy efficiency as an alternative to the proposed Big Stone II coal project. On behalf of the Minnesota Center for Environmental Advocacy, Fresh Energy, Izaak Walton League of America, Wind on the Wires and the Union of Concerned Scientists. November 29, 2006.

Rhode Island Public Utilities Commission (Docket No. 3779): Oral testimony regarding the settlement of Narragansett Electric Company's 2007 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 24, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-04002 & 06-04005): Direct testimony regarding Nevada Power Company's and Sierra Pacific Power Company's Renewable Portfolio Standard Annual Report. On behalf of the Nevada Bureau of Consumer Protection. October 26, 2006

Nevada Public Utilities Commission (Docket No. 06-06051): Direct testimony regarding Nevada Power Company's Demand-Side Management Plan in the 2006 Integrated Resource Plan. On behalf of the Nevada Bureau of Consumer Protection. September 13, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-03038 & 06-04018): Direct testimony regarding the Nevada Power Company's and Sierra Pacific Power Company's Demand-Side Management Plans. On behalf of the Nevada Bureau of Consumer Protection. June 20, 2006.

Nevada Public Utilities Commission (Docket No. 05-10021): Direct testimony regarding the Sierra Pacific Power Company's Gas Demand-Side Management Plan. On behalf of the Nevada Bureau of Consumer Protection. February 22, 2006.

South Dakota Public Utilities Commission (Docket No. EL04-016): Direct testimony regarding the avoided costs of the Java Wind Project. On behalf of the South Dakota Public Utilities Commission Staff. February 18, 2005.

Rhode Island Public Utilities Commission (Docket No. 3635): Oral testimony regarding the settlement of Narragansett Electric Company's 2005 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 29, 2004.

British Columbia Utilities Commission. Direct testimony regarding the Power Smart programs contained in BC Hydro's Revenue Requirement Application 2004/05 and 2005/06. On behalf of the Sierra Club of Canada, BC Chapter. April 20, 2004.

Maryland Public Utilities Commission (Case No. 8973): Oral testimony regarding proposals for the PJM Generation Attributes Tracking System. On behalf of the Maryland Office of People's Counsel. December 3, 2003.

Rhode Island Public Utilities Commission (Docket No. 3463): Oral testimony regarding the settlement of Narragansett Electric Company's 2004 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 21, 2003.

California Public Utilities Commission (Rulemaking 01-10-024): Direct testimony regarding the market price benchmark for the California renewable portfolio standard. On behalf of the Union of Concerned Scientists. April 1, 2003.

Québec Régie de l'énergie (Docket R-3473-01): Direct testimony with Philp Raphals regarding Hydro-Québec's Energy Efficiency Plan: 2003-2006. On behalf of Regroupment national des Conseils régionaux de l'environnement du Québec. February 5, 2003.

Connecticut Department of Public Utility Control (Docket No. 01-10-10): Direct testimony regarding the United Illuminating Company's service quality performance standards in their performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. April 2, 2002.

Nevada Public Utilities Commission (Docket No. 01-7016): Direct testimony regarding the Nevada Power Company's Demand-Side Management Plan. On behalf of the Bureau of Consumer Protection, Office of the Attorney General. September 26, 2001.

United States Department of Energy (Docket Number-EE-RM-500): Comments with Bruce Biewald, Daniel Allen, David White, and Lucy Johnston of Synapse Energy Economics regarding the Department of Energy's proposed rules for efficiency standards for central air conditioners and heat pumps. On behalf of the Appliance Standards Awareness Project. December 2000.

US Department of Energy (Docket EE-RM-500): Oral testimony at a public hearing on marginal price assumptions for assessing new appliance efficiency standards. On behalf of the Appliance Standards Awareness Project. November 2000.

Connecticut Department of Public Utility Control (Docket No. 99-09-03 Phase II): Direct testimony regarding Connecticut Natural Gas Company's proposed performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. September 25, 2000.

Mississippi Public Service Commission (Docket No. 96-UA-389): Oral testimony regarding generation pricing and performance-based ratemaking. On behalf of the Mississippi Attorney General. February 16, 2000.

Delaware Public Service Commission (Docket No. 99-328): Direct testimony regarding maintaining electric system reliability. On behalf of Delaware Public Service Commission Staff. February 2, 2000.

Delaware Public Service Commission (Docket No. 99-328): Filed expert report ("Investigation into the July 1999 Outages and General Service Reliability of Delmarva Power & Light Company," jointly authored with J. Duncan Glover and Alexander Kusko). Synapse Energy Economics and Exponent Failure Analysis Associates on behalf the Delaware Public Service Commission Staff. February 1, 2000.

New Hampshire Public Service Commission (Docket No. 99-099 Phase II): Oral testimony regarding standard offer services. On behalf of the Campaign for Ratepayers Rights. January 14, 2000.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Rebuttal testimony regarding codes of conduct. On behalf of the West Virginia Consumer Advocate Division. July 15, 1999.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Direct testimony regarding codes of conduct and other measures to protect consumers in a restructured electricity industry. On behalf of the West Virginia Consumer Advocate Division. June 15, 1999.

Public Service Commission of West Virginia (Case No. 98-0452-E-GI): Filed expert report ("Measures to Ensure Fair Competition and Protect Consumers in a Restructured Electricity Industry in West Virginia," jointly authored with Jean Ann Ramey and Theo MacGregor) in the matter of the General Investigation to determine whether West Virginia should adopt a plan for open access to the electric power supply market and for the development of a deregulation plan. Synapse Energy Economics and MacGregor Energy Consultancy on behalf of the West Virginia Consumer Advocate Division. June 1999.

Massachusetts Department of Telecommunications and Energy (DPU/DTE 97-111): Direct testimony regarding Commonwealth Electric Company's energy efficiency plan, and the role of municipal aggregators in delivering demand-side management programs. On behalf of Cape and Islands Self-Reliance Corporation. January 1998.

Delaware Public Service Commission (DPSC 97-58): Direct testimony regarding Delmarva Power and Light's request to merge with Atlantic City Electric. On behalf of Delaware Public Service Commission Staff. May 1997.

Delaware Public Service Commission (DPSC 95-172): Oral testimony regarding Delmarva's integrated resource plan and DSM programs. On behalf of the Delaware Public Service Commission Staff. May 1996.

Colorado Public Utilities Commission (5A-531EG): Direct testimony regarding the impact of proposed merger on DSM, renewable resources and low-income DSM. On behalf of the Colorado Office of Energy Conservation. April 1996.

Colorado Public Utilities Commission (3I-199EG): Direct testimony regarding the impacts of increased competition on DSM, and recommendations for how to provide utilities with incentives to implement DSM. On behalf of the Colorado Office of Energy Conservation. June 1995.

Colorado Public Utilities Commission (5R-071E): Oral testimony on the Commission's integrated resource planning rules. On behalf of the Colorado Office of Energy Conservation. July 1995.

Colorado Public Utilities Commission (3I-098E): Direct testimony on the Public Service Company of Colorado's DSM programs and integrated resource plans. On behalf of the Colorado Office of Energy Conservation. April 1994.

Delaware Public Service Commission (Docket No. 96-83): Filed comments regarding the Investigation of Restructuring the Electricity Industry in Delaware (Tellus Institute Study No. 96-99). On behalf of the Staff of the Delaware Public Service Commission. November 1996.

Colorado Public Utilities Commission (Docket No. 96Q-313E): Filed comments in response to the Questionnaire on Electricity Industry Restructuring (Tellus Institute Study No. 96-130-A3). On behalf of the Colorado Governor's Office of Energy Conservation. October 1996.

State of Vermont Public Service Board (Docket No. 5854): Filed expert report (Tellus Institute Study No. 95-308) regarding the Investigation into the Restructuring of the Electric Utility Industry in Vermont. On behalf of the Vermont Department of Public Service. March 1996.

Pennsylvania Public Utility Commission (Docket No. I-00940032): Filed comments (Tellus Institute Study No. 95-260) regarding an Investigation into Electric Power Competition. On behalf of The Pennsylvania Office of Consumer Advocate. November 1995.

New Jersey Board of Public Utilities (Docket No. EX94120585Y): Initial and reply comments ("Achieving Efficiency and Equity in the Electricity Industry Through Unbundling and Customer Choice," Tellus Institute Study No. 95-029-A3) regarding an investigation into the future structure of the electric power industry. On behalf of the New Jersey Division of Ratepayer Advocate. September 1995.

ARTICLES

Woolf, T., E. Malone, C. Neme, R. LeBaron. 2014. "Unleashing Energy Efficiency." *Public Utilities Fortnightly,* October, 30-38.

Woolf, T., A. Sommer, J. Nielson, D. Berry, R. Lehr. 2005. "Managing Electricity Industry Risk with Clean and Efficient Resources." *The Electricity Journal* 18 (2): 78–84.

Woolf, T., A. Sommer. 2004. "Local Policy Measures to Improve Air Quality: A Case Study of Queens County, New York." *Local Environment* 9 (1): 89–95.

Woolf, T. 2001. "Clean Power Opportunities and Solutions: An Example from America's Heartland." *The Electricity Journal* 14 (6): 85–91.

Woolf, T. 2001. "What's New With Energy Efficiency Programs." *Energy & Utility Update, National Consumer Law Center*: Summer 2001.

Woolf T., B. Biewald. 2000. "Electricity Market Distortions Associated With Inconsistent Air Quality Regulations." *The Electricity Journal* 13 (3): 42–49.

Ackerman, F., B. Biewald, D. White, T. Woolf, W. Moomaw. 1999. "Grandfathering and Coal Plant Emissions: the Cost of Cleaning Up the Clean Air Act." *Energy Policy* 27 (15): 929–940.

Biewald, B., D. White, T. Woolf. 1999. "Follow the Money: A Method for Tracking Electricity for Environmental Disclosure." *The Electricity Journal* 12 (4): 55–60.

Woolf, T., B. Biewald. 1998. "Efficiency, Renewables and Gas: Restructuring As if Climate Mattered." *The Electricity Journal* 11 (1): 64–72.

Woolf, T., J. Michals. 1996. "Flexible Pricing and PBR: Making Rate Discounts Fair for Core Customers." *Public Utilities Fortnightly,* July 1996.

Woolf, T., J. Michals. 1995. "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry." *The Electricity Journal* 8 (8): 64–72.

Woolf, T. 1994. "Retail Competition in the Electricity Industry: Lessons from the United Kingdom." *The Electricity Journal* 7 (5): 56–63.

Woolf, T. 1994. "A Dialogue About the Industry's Future." *The Electricity Journal* 7 (5).

Woolf, T., E. D. Lutz. 1993. "Energy Efficiency in Britain: Creating Profitable Alternatives." *Utilities Policy* 3 (3): 233–242.

Woolf, T. 1993. "It is Time to Account for the Environmental Costs of Energy Resources." *Energy and Environment* 4 (1): 1–29.

Woolf, T. 1992. "Developing Integrated Resource Planning Policies in the European Community." *Review of European Community & International Environmental Law* 1 (2) 118–125.

PRESENTATIONS

Woolf, T., M. Whited. 2016. "Show Me the Numbers: A Framework for Balanced Distributed Solar Policies." Presentation for Consumers Union Webinar, December 2016.

Woolf, T. 2016. "Show Me the Numbers: Balancing Solar DG with Consumer Protection." Public workshop on solar distributed generation for the Federal Trade Commission, June 2016.

Woolf, T. 2016. "Rate Designs for Distributed Generation: State Activities & A New Framework." Presentation at the NASUCA 2016 Mid-Year Meeting, June 2016.

Woolf, T., M. Whited. 2016. "3rd Annual 21st Century Electricity System Workshop – Implications of Different Rate Designs." Presentation at the Advanced Energy Economy Institute, April 2016.

Woolf, T., M. Whited. 2016. “Decoupling in Pennsylvania: Advantages, Disadvantages, and Design Issues.” Presentation to Pennsylvania Decoupling Stakeholders, February 2016.

Woolf, T. 2016. “Earnings Impact Mechanisms: Energy Efficiency.” Presentation at the New York REV Technical Conference, January 2016.

Lowry, M. N., T. Woolf. 2015. “Performance-Based Regulation in a High Distributed Energy Resources Future.” Webinar on January 2016.

Woolf, T. 2015. “Performance Incentive Mechanisms: A Catalyst for Change.” Webinar for Power Sector Transformation Group, December 2015.

Woof, T. 2015. “Energy Efficiency Valuation: Boogie Men, Time Warps, and other Terrifying Pitfalls.” Presentation at ACEEE Conference on Energy Efficiency as a Resource, September 2015.

Woolf, T., M. Whited, A. Napoleon. 2015. “Thoughts on How to Design Clean Energy Performance Incentive Mechanisms.” Webinar for the Western Clean Energy Advocates, April 2015.

Woolf, T. 2015. “Properly Valuing the Benefits and Costs of Energy Efficiency.” Presentation at the 2015 National Efficiency Advocates Meeting, April 2015.

Woolf, T. 2015. “Non-Energy Benefits & Efficiency Program Screening.” Presentation for Georgia DSM Work Group, March 2015.

Woolf, T. 2014. “Performance Incentive Mechanisms And Their Role in New Regulatory Models.” Presentation at Acadia Center Conference, Envisioning Our Energy Future, December 2014.

Woolf, T., M. Whited., A. Napoleon. 2014. “Guiding Utility Performance: A Handbook for Regulators.” Webinar for the Western Interstate Energy Board, December 2014.

Woolf, T. 2014. “Planning for Distributed Energy Resources.” Presentation for Advanced Energy Economy Webinar, November 2014.

Woolf, T. 2014. “Benefit-Cost Analysis for Distributed Energy Resources in New York: A Framework for Accounting for All Relevant Costs and Benefits.” Presentation to NARUC ERE Committee, November 2014.

Woolf, T. 2014. “Presenting the Full Value of Energy Efficiency: Creating a Better Message.” Presentation at Sierra Club Beyond Coal Conference, October 2014.

Woolf, T., C. Neme. 2014. “Regulatory Policies to Support Energy Efficiency in Virginia.” Presentation for the 2014 Virginia Energy Efficiency Workshop, October 2014.

Woolf, T. 2014. “Benefit-Cost Analysis for Distributed Energy Resources in New York: A Framework for Accounting for All Relevant Costs and Benefits.” Presentation for Advanced Energy Economy Institute, October 2014.

Woolf, T. 2014. “Performance Incentive Mechanisms: Digging Deeper Into Performance-Based Regulation.” Presentation for National Governor’s Association Conference: Utility Business Models That Align with State Clean Energy Goals, September 2014.

Woolf, T. 2014. “The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening.” Presentation at the ACEEE Summer Study, August 2014.

Woolf, T. 2014. “Cost-Effectiveness of Demand Response.” Presentation at MADRI Working Group Meeting #34, July 2014.

Woolf, T. 2014. “Time to Overhaul Our Energy Efficiency Screening Practices.” Presentation for U.S. Environmental Protection Agency Energy Efficiency Cost-Effectiveness Webinar, January 2014.

Woolf, T. 2013. “Survey of Energy Efficiency Screening Practices in the Northeast and Mid-Atlantic.” Presentation for Northeast Energy Efficiency Partnerships EM&V Forum Annual Public Meeting, December 2013.

Woolf, T. 2013. “Recommendations for Reforming Energy Efficiency Cost-Effectiveness Screening in the United States.” Presentation at the National Association of Regulatory Commissioners Annual Meeting, November 2013.

Woolf, T. 2013. “Energy Efficiency Program Screening: Let’s Get Beyond the TRC Test.” Presentation for 7th Annual ENERGY STAR Certified Homes Utility Sponsor Meeting, October 2013.

Woolf, T. 2013. “Decoupling in Maine: Why Decoupling is in Consumers’ Interest.” Presentation for Office of Public Advocate- Decoupling Debate, October 2013.

Woolf, T. 2013. “NHPC Efficiency Screening Initiative: Unleashing the Potential for Energy Efficiency.” Presentation for Advocates Meeting, September 2013.

Woolf, T. 2013. “Energy Efficiency: Rate, Bill and Participation Impacts.” Presentation for ACEEE’s Energy Efficiency as a Resource Conference, September 2013.

Woof, T. 2013. “Energy Efficiency Screening: Challenges and Opportunities.” Presentation for NARUC Summer Meeting Consumer Affairs Panel, July 2013.

Woolf, T., R. Sedano. 2013. “Decoupling Overview.” Presentation for Finding Common Ground Meeting, July 2013.

Woolf, T. 2013. “Utility Incentives for Energy Efficiency.” Presentation for Finding Common Ground Meeting, July 2013.

Woolf, T. 2013. “Energy Efficiency: Rate, Bill and Participation Impacts.” Presentation for State Energy Efficiency Action Webinar, June 2013.

Woolf, T., B. Biewald, and J. Migden-Ostrander. 2013. “NARUC Risk Workshop for Regulators.” Presentation at the Mid-Atlantic Conference of Regulatory Utility Commissioners, June 2013.

Woolf, T. 2013. "Energy Efficiency Screening: Accounting for 'Other Program Impacts' & Environmental Compliance Costs." Presentation for the Consortium for Energy Efficiency Summer Meeting, May 2013.

Woolf, T. 2013. "Best Practices in Energy Efficiency Program Screening." Presentation at ACI National Home Performance Conference, May 2013.

Woolf, T. 2013. "Utility Shareholder Incentives to Support Energy Efficiency Programs." Presentation to Common Ground, May 2013.

Woolf, T. 2013. "Energy Efficiency Screening: Accounting for 'Other Program Impacts' & Environmental Compliance Costs." Presentation for Regulatory Assistance Project Webinar, March 2013.

Woolf, T. 2013. "Energy Efficiency: Rates, Bills, Participants, Screening, and More." Presentation at Connecticut Energy Efficiency Workshop, March 2013.

Woolf T. 2013. "Best Practices in Energy Efficiency Program Screening." Presentation for SEE Action Webinar, March 2013.

Woolf, T. 2013. "Energy Efficiency: Rates, Bills and Participants." Presentation for Rhode Island Energy Efficiency Collaborative, February 2013.

Woolf, T. 2013. "Energy Efficiency Screening: Application of the TRC Test." Presentation for Energy Advocates Webinar, January 2013.

Woolf, T. 2012. "Best Practices in Energy Efficiency Program Screening." Presentation for American Council for an Energy-Efficient Economy Webinar, December 2012.

Woolf, T. 2012. Indian Point Replacement Analysis: A Clean Energy Roadmap. Presentation for Natural Resource Defenses Council and Environmental Entrepreneurs, November 2012.

Woolf, T. 2012. "In Pursuit of All Cost-Effective Energy Efficiency." Presentation at Sierra Club Boot Camp, October 2012.

Woolf, T. 2012. "Best Practices in Energy Efficiency Program Screening." Webinar for Northeast Energy Efficiency Partnerships, September 2012.

Woolf, T., L. Schwartz. "What Remains to be Done with Demand Response? A National Forum from the FERC National Action Plan on Demand Response Tries to Give an Answer." Presentation at NARUC National Town Meeting on Demand Response, July 2012.

Woolf, T. 2012. "Best Practices in Energy Efficiency Program Screening." Presentation at NARUC Summer Meetings – Energy Efficiency Cost-Effectiveness Breakfast, July 2012.

Woolf, T. 2012. "Avoided Cost of Complying with Environmental Regulations in MA." Presentation for Mass Energy Consumer's Alliance, January 2012.

Woolf, T. 2011. "Energy Efficiency Cost-Effectiveness Tests." Presentation at the Northeast Energy Efficiency Partnerships Annual Meeting, October 2011.

Woolf, T. 2011. “Why Consumer Advocates Should Support Decoupling.” Presentation at the 2011 ACEEE National Conference on Energy Efficiency as a Resource, September 2011.

Woolf, T. 2011. “A Regulator’s Perspective on Energy Efficiency.” Presentation at the Efficiency Maine Symposium *In Pursuit of Maine’s Least-Cost Energy*, September 2011.

Woolf, T. 2010. “Bill Impacts of Energy Efficiency Programs: The Importance of Analyzing and Managing Rate and Bill Impacts.” Presentation at the Energy in the Northeast Conference, Law Seminar International, September 2010.

Woolf, T. 2010. “Bill Impacts of Energy Efficiency Programs: The Implications of Bill Impacts in Developing Policies to Motivate Utilities to Implement Energy Efficiency.” Presentation to the State Energy Efficiency Action Network, Utility Motivation Work Group, November 2010.

Woolf, T. 2010. “Bill Impacts of Energy Efficiency Programs.” Presentation to the Energy Resources and Environment Committee at the NARUC Winter Meetings, February 2010.

Woolf, T. 2009. “Price-Responsive Demand in the New England Wholesale Energy Market: Description of NECPUC’s Limited Supply-Side Proposal.” Presentation at the NEPOOL Markets Committee Meeting, November 2009.

Woolf, T. 2009. “Demand Response in the New England Wholesale Energy Market: How Much Should We Pay for Demand Resources?” Presentation at the New England Electricity Restructuring Roundtable, October 2009.

Woolf, T. 2008. “Promoting Demand Resources in Massachusetts: A Regulator’s Perspective.” Presentation at the Energy Bar Association, Northeast Chapter Meeting, June 2008.

Woolf, T. 2008. “Turbo-Charging Energy Efficiency in Massachusetts: A DPU Perspective.” Presentation at the New England Electricity Restructuring Roundtable, April 2008.

Woolf T. 2002. “A Renewable Portfolio Standard for New Brunswick.” Presentation to the New Brunswick Market Design Committee, January 10, 2002.

Woolf, T. 2001. “Potential for Wind and Renewable Resource Development in the Midwest.” Presentation at WINDPOWER 2001 in Washington DC, June 7, 2001.

Woolf T. 1999. “Challenges Faced by Clean Generation Resources Under Electricity Restructuring.” Presentation at the Symposium on the Changing Electric System in Florida and What it Means for the Environment in Tallahassee, FL, November 1999.

Woolf, T. 2000. “Generation Information Systems to Support Renewable Portfolio Standards, Generation Performance Standards and Environmental Disclosure.” Presentation at the Massachusetts Restructuring Roundtable on behalf of the Union of Concerned Scientists, March 2000.

Woolf, T. 1998. “New England Tracking System Project: An Electricity Tracking System to Support a Wide Range of Restructuring-Related Policies.” Presentation at the Ninth Annual Energy Services Conference and Exposition in Orlando, FL, December 1998.

Woolf, T. 2000. “Comments of the Citizens Action Coalition of Indiana.” Presentation at Workshop on Alternatives to Traditional Generation Resources, June 2000.

Woolf, T. 1996. “Overview of IRP and Introduction to Electricity Industry Restructuring.” Training session provided to the staff of the Delaware Public Service Commission, April 1996.

Woolf, T. 1995. “Competition and Regulation in the UK Electric Industry.” Presentation at the Illinois Commerce Commission's workshop on Restructuring the Electric Industry, August 1995.

Woolf, T. 1995. “Competition and Regulation in the UK Electric Industry.” Presentation at the British Columbia Utilities Commission Electricity Market Review, February 1995.

Resume dated March 2018

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge MA. *Principal Associate,* 2017 – present*, Senior Associate,* 2015 – 2017*, Associate*, 2012 – 2015

Conduct research, author reports, and assist in preparation of expert testimony. Consult on issues related to distributed energy resources, rate design, cost-benefit analysis, integrated resource planning, utility regulation, water use and conservation, and market power.

University of Wisconsin - Madison, Department of Agricultural and Applied Economics, Madison, WI. *Teaching Assistant – Environmental Economics*, 2011 – 2012

Developed teaching materials and led discussions on cost-benefit analysis, carbon taxes and cap-and-trade programs, management of renewable and non-renewable resources, and other topics.

Public Service Commission of Wisconsin, Water Division, Madison, WI. *Program and Policy Analyst - Intern*, Summer 2009

Researched water conservation programs nationwide to develop a proposal for Wisconsin's state conservation program. Developed spreadsheet model to calculate avoided costs of water conservation in terms of energy savings and avoided emissions.

Synapse Energy Economics, Cambridge, MA. *Communications Manager*, 2005 – 2008

Developed technical proposals for state and federal agencies, environmental and public interest groups, and businesses. Edited reports on energy efficiency, integrated resource planning, greenhouse gas regulations, renewable resources, and other topics.

EDUCATION

University of Wisconsin, Madison, WI
Master of Arts in Agricultural and Applied Economics, 2012.
Certificate in Energy Analysis and Policy.
National Science Foundation Fellow.

University of Wisconsin, Madison, WI
Master of Science in Environment and Resources, 2010.
Certificate in Humans and the Global Environment (CHANGE).
Nelson Distinguished Fellowship.

Southwestern University, Georgetown, TX
Bachelor of Arts in International Studies, *Magna cum laude,* 2003.

ADDITIONAL SKILLS

- Econometric Modeling – Linear and nonlinear modeling including time-series, panel data, logit, probit, and discrete choice regression analysis
- Nonmarket Valuation Methods for Environmental Goods – Hedonic valuation, travel cost method, and contingent valuation
- Cost-Benefit Analysis
- Input-Output Modeling for Regional Economic Analysis

FELLOWSHIPS AND AWARDS

- Winner, M. Jarvin Emerson Student Paper Competition, Journal of Regional Analysis and Policy, 2010
- Fellowship, National Science Foundation Integrative Graduate Education and Research Traineeship (IGERT), University of Wisconsin – Madison, 2009
- Nelson Distinguished Fellowship, University of Wisconsin – Madison, 2008

PUBLICATIONS

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Resume dated March 2018

Direct Testimony of Tim Woolf and Melissa Whited
RIDPUC Docket No. 4770
Exhibit TW/MW-3

Assumptions for the Benefit-Cost Analysis
Used to Determine PIM Incentive Levels

Contents

1. Introduction

Ideally, performance incentives should be proportionate to the importance of the performance goal to customers, and they should not exceed the net benefits to customers (including both quantified and unquantified benefits). We applied this principle by estimating the benefits and the costs associated with achieving each PIM, and then assigning a portion of net benefits to the utility in the form of an incentive payment.

Below we describe the assumptions and data sources that we relied upon to calculate the benefits and costs associated with meeting each PIM. Additional details on the assumptions and calculations are provided in Exhibit TW/MW-4, which is the Excel workbook used to make the calculations.

2. Avoided Costs

Avoided Generation Capacity Costs

Daymark estimated avoided generation capacity costs for 2019–2038 using Daymark's proprietary capacity model and the cost of new entry (CONE) for Forward Capacity Auction (FCA) clearing prices. These cost estimates rely on the 2017 CELT Load Forecast for 2016 through 2026, with projections for load between 2027–2038 and assuming a 14.3 percent planning reserve margin.

Because FCAs 10, 11, and 12 have already been completed, the avoided costs for 2019–2021 are assumed to be zero. While there could be a small benefit through reconfiguration auctions, these benefits are assumed to be negligible.

Table 1 below shows avoided generation costs in $/MW-year for 2019 through 2030 in nominal dollars. We note that these values are substantially lower than those assumed by the Company (which were based on AESC 2015).

Avoided Transmission Capacity Costs

Avoided transmission costs were estimated by Daymark for 2019-2038. These cost estimates rely on the 2017 CELT Load Forecast for 2016 through 2026, with projections for load between 2027–2038, Section II Open Access Tariff Rates, and Planning Procedure PP04—Procedure for Pool-Supported PTF Cost Review. The methodology assumes that load is reduced only for Rhode Island and not for the rest of the ISO New England system. Avoided transmission costs in $/MW-year for 2019 through 2030 are shown in the table below in nominal dollars. Note that a MW reduction for only one month would be associated with a benefit of 8 percent of the annual ($/MW-year) value.

Avoided Distribution Costs

Avoided distribution capacity costs were based on National Grid's Energy Efficiency Screening tool. Table 1 below provides these values for 2019 through 2030 (assuming 2 percent inflation). These values are provided in $/MW-year terms.

Avoided Peak Hour Energy Costs

Avoided cost estimates for peak hour energy reductions were developed by Daymark using Daymark's Energy Model. These values are based on modeled locational marginal prices and do not assume any change in the LMP due to load reduction.

The average value of reducing energy consumption during the peak load hour was calculated assuming a 2.5 percent reduction in peak load. Table 1 below shows the values in $/MWh for 2019–2030.

Avoided Greenhouse Gas Emissions

We used the same estimate for the value of avoided greenhouse gas emissions as used by National Grid, which come from the 2015 Avoided Energy Supply Cost study, Exhibit 4-7. These values in $/short ton are provided below for 2019–2030.

Table 1. Avoided Costs for Years 2019–2030

Year	Avoided Capacity Costs ($/MW-yr)	Avoided Transmission Costs ($/MW-yr)	Avoided Distribution Costs ($/MW-yr)	Avoided Peak Hour Energy Costs ($/MWh)	Non-Embedded CO_2 Cost ($/short ton)
2019	0	$124,913	$80,000	$80	$94
2020	0	$133,170	$84,897	$82	$95
2021	0	$141,612	$86,595	$74	$95
2022	$55,042	$150,390	$88,326	$76	$94
2023	$55,936	$159,312	$90,093	$77	$93
2024	$62,393	$168,380	$91,895	$83	$92
2025	$64,297	$177,593	$93,733	$87	$91
2026	$69,950	$186,950	$95,607	$94	$90
2027	$75,749	$196,453	$97,520	$96	$89
2028	$84,529	$206,100	$99,470	$101	$88
2029	$102,516	$215,893	$101,459	$110	$87
2030	$97,070	$225,830	$103,489	$116	$85

3. Discount Rate

To estimate the net benefits of each PIM, we included societal benefits consistent with the Rhode Island Benefit-Cost Framework. Therefore, we applied a societal discount rate of 3 percent (equivalent to approximately 5.5 percent nominal).

4. Peak Coincidence Factors

Not all reductions in demand will have the same impact on the grid. For example, a reduction in the monthly peak demand for the month of April would provide a benefit in terms of avoided transmission costs for that month, but it would not provide a benefit in terms of forward capacity market (FCM) costs, unless it was assumed to be available in the annual peak hour as well. For each PIM, we made assumptions regarding the extent to which measures implemented for one PIM would help to avoid annual peak demand, monthly transmission peak demand, and local distribution peak demand (that is, at the feeder or substation level).

These assumptions are expressed in terms of assumed coincidence factors, which are then multiplied by the targets to develop assumed MW reductions for each type of demand reduction. These coincidence factors are shown in the table below for the System Efficiency and distributed energy resource PIMs.

Table 2. Assumed Peak Demand Coincidence for Measures Implemented to Achieve Each PIM

Performance Incentive Mechanism	FCM Peak Coincidence	Transmission Peak Coincidence	Distribution Peak Coincidence
Transmission Peak Demand Reduction	0%	100%	5%
FCM Peak Demand Reduction	100%	8%	20%
Demand Response - Residential	100%	25%	80%
Demand Response - C&I	100%	25%	80%
Electric Heat Initiative	0%	0%	0%
Electric Vehicle Initiative	0%	0%	0%
Behind-the-Meter Storage	80%	30%	40%
Utility-Scale Storage	90%	90%	90%
Non-Wires Alternatives	60%	30%	100%

5. Assumed Costs to Customers of Implementing PIM

The cost of an initiative or technology implemented to achieve a PIM will have a large impact on the net benefits that the PIM provides. For the FCM Peak and Transmission Peak PIMs we assumed that there will be no additional cost to the customers, because the Company has not requested recovery of any such costs in this rate case.

For most of the PIM initiatives (e.g., residential demand response, behind-the-meter storage), the forward-going costs are not known at this time. Our cost estimates are based on our understanding of the general cost-effectiveness of the relevant technology or program. Although these costs are not known with great certainty, the majority of these PIMs are designed to provide shared savings so that the Company is rewarded only when the PIM is cost-effective.

Our assumptions regarding the costs of achieving the PIM targets are expressed as a percent of benefits in the table below.

Table 3. Assumed Costs to Customers as Percent of Benefits for Each PIM

Performance Incentive Mechanism	Assumed Costs as % of Benefits
Transmission Peak Demand Reduction	0%
FCM Peak Demand Reduction	0%
Demand Response - Residential	90%
Demand Response - C&I	70%
Electric Heat Initiative	71%
Electric Vehicle Initiative	80%
Behind-the-Meter Storage	90%
Utility-Scale Storage	90%
Non-Wires Alternatives	90%

6. PIM Incentives

Our approach to calculating the PIM incentives to provide to the Company includes the following steps.

First, we determined the quantified net benefits for each of the PIM initiatives. These are based on all of the assumptions described above.

Second, we determined how the quantified net benefits should be shared between the Company and customers. For each PIM, we propose that the net benefits be shared on a 50/50 basis.

Third, we divided the quantified net benefits by the expected value of a basis point in each year, using the Company's assumptions. These assumptions may change if the revenue requirement is changed from the Company's assumption. The table below provides the assumed value of a basis point.

Table 4. Assumed Value per Basis Point ($/bp)

2019	2020	2021
$59,493	$60,526	$63,602

Fourth, we identified additional unquantified benefits associated with each of the PIMs. We assumed these to be in the form of (a) improved reliability or resilience; (b) other fuel benefits; (c) market innovation or transformation benefits; or (d) low-income benefits. We chose the number of basis points for each PIM based upon the type and number of unquantified benefits, and the importance of each unquantified benefit in light of Docket 4600 goals and state energy policies. The table below shows the categories of likely unquantified benefits and the basis points assigned to reflect these benefits.

Table 5. Basis Points for Unquantified Benefits

Performance Incentive Mechanism	Unquantified Benefits	2019 Med (bps)	2019 High (bps)	2020 Med (bps)	2020 High (bps)	2021 Med (bps)	2021 High (bps)
Transmission Peak Reduction		-	-	-	-	-	-
FCM Peak Demand Reduction		-	-	-	-	-	-
Demand Response - Residential	Reliability, Market Transformation	1	1	1	1	1	1
Demand Response - C&I	Reliability, Market Transformation	1	1	1	1	1	1
Electric Heat Initiative	Reliability, Market Transformation, Low Income Benefits	1	2	1	2	1	2
Electric Vehicle Initiative	Market Transformation	2	3	2	3	2	3
Behind-the-Meter Storage	Reliability, Market Transformation	1	2	1	2	1	2
Utility-Scale Storage	Reliability, Market Transformation	1	2	1	2	1	2
Non-Wires Alternatives	Market Transformation	1	2	1	2	1	2
Low-Income: participation in PST	Low-Income Benefits	2	3	2	3	2	3
Low-Income: participation in A60	Low-Income Benefits	2	3	2	3	2	3
Provision of Customer Information	PST Support	1	-	-	-	-	-
Peak Demand Forecasting	PST Support	1	-	-	-	-	-

DIVISION EXHIBIT 4
SUBMITTED IN DOCKET 4770
ON BEHALF OF THE DIVISION OF PUBLIC UTILITIES AND CARRIERS

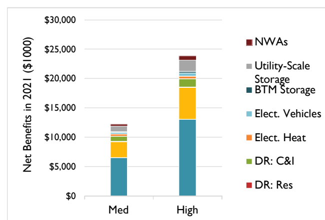
SUMMARY
Division Proposal

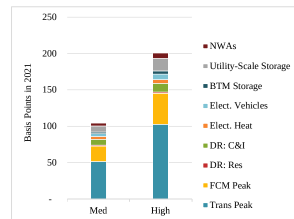
Performance Incentive Mechanism	Bps or Shared Savings	% to Company	Assumed Costs as % of Benefits	BCR	Target Units	Targets 2019 Medium	Targets 2019 High	Targets 2020 Medium	Targets 2020 High	Targets 2021 Medium	Targets 2021 High
System Efficiency											
Transmission Peak Demand Reduction	bps	50%	0%		MW below baseline	228	342	255	383	284	425
FCM Peak Demand Reduction	bps	50%	0%		MW below baseline	29	44	31	46	32	48
Distributed Energy Resources											
Demand Response - Residential	shared savings	50%	90%	1.11	Incremental MW	1	2	2	3	3	4
Demand Response - C&I	shared savings	50%	70%	1.43	Incremental MW	8	14	10	16	12	18
Electric Heat Initiative	shared savings	50%	71%	1.40	Incremental Tonnes CO2	464	556	580	696	595	714
Electric Vehicle Initiative	bps	50%	80%	1.25	Incremental Tonnes CO2	557	1,114	757	1,511	1,026	2,051
Behind-the-Meter Storage	shared savings	50%	90%	1.11	Incremental MW	1	2	1	2	1	2
Utility-Scale Storage	shared savings	50%	90%	1.11	Incremental MW	3	6	3	6	3	6
Non-Wires Alternatives	shared savings	50%	90%	1.11	Incremental MW	3	6	3	6	3	6
Existing Energy Efficiency		5%	33%	3.03	Incremental MW	30	37	35	38	34	38
PST Support Services											
Low-Income: participation in PST initiatives	bps				% LI cust in initiative	5	10	5	10	5	10
Low-Income: participation in LI rate	bps				% LI cust in initiative	4	8	4	8	4	8
Data Access	bps					Plan	--	--	--	--	--
Peak Demand Forecasting (one-year)	bps					Report	--	--	--	--	--
AMI Capabilities (2022)					# cust with TVR	--	--	--	--	--	--
Subtotal Existing PIMs											
Subtotal New PIMs											
Total PIMs											
					Monthly Tx MW	21	31	23	35	26	39

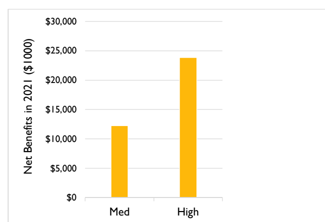
Performance Incentive Mechanism	Quantified Net Benefits ($1000) (before incentive) 2019 Medium	2019 High	2020 Medium	2020 High	2021 Medium	2021 High	Unquantified Benefits	Additional Bps for Unquantified Benefits 2019 Medium (bps)	2019 High (bps)	2020 Medium (bps)	2020 High (bps)	2021 Medium (bps)	2021 High (bps)
System Efficiency													
Transmission Peak Demand Reduction	$4,765	$9,531	$5,599	$11,198	$6,531	$13,062		-	-	-	-	-	-
FCM Peak Demand Reduction	$1,054	$2,108	$1,814	$3,629	$2,702	$5,405		-	-	-	-	-	-
Distributed Energy Resources													
Demand Response - Residential	$9	$17	$27	$46	$59	$88	R&R; Mkt Trnsf	1	1	1	1	1	1
Demand Response - C&I	$206	$360	$491	$819	$881	$1,410	R&R; Mkt Trnsf	1	1	1	1	1	1
Electric Heat Initiative	$263	$315	$329	$395	$337	$405	R&R; Mkt Trnsf; LI	1	2	1	2	1	2
Electric Vehicle Initiative	$67	$134	$157	$313	$276	$551	Mkt Trnsf	2	3	2	3	2	3
Behind-the-Meter Storage	$38	$75	$87	$173	$146	$292	R&R; Mkt Trnsf	1	2	1	2	1	2
Utility-Scale Storage	$270	$539	$595	$1,190	$963	$1,926	R&R; Mkt Trnsf	1	2	1	2	1	2
Non-Wires Alternatives	$96	$192	$213	$425	$354	$709	Mkt Trnsf	1	2	1	2	1	2
Existing Energy Efficiency	$314,010	$314,010	$342,693	$342,693	$342,693	$342,693		-	-	-	-	-	-
PST Support Services													
Low-Income: participation in PST initiatives							LI benefits	2	3	2	3	2	3
Low-Income: participation in LI rate							LI benefits	2	3	2	3	2	3
Data Access							PST Support	1	-	-	-	-	-
Peak Demand Forecasting (one-year)							PST Support	1	-	-	-	-	-
AMI Capabilities (2022)													
Subtotal Existing PIMs	$314,010	$314,010	$342,693	$342,693	$342,693	$342,693							
Subtotal New PIMs	$6,767	$13,271	$9,312	$18,187	$12,250	$23,848							
Total PIMs	$320,777	$327,281	$352,005	$360,880	$354,943	$366,541							

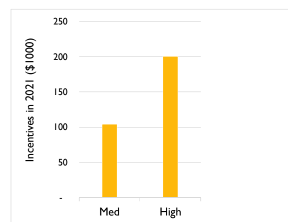
Performance Incentive Mechanism	Incentives (Basis Points) 2019 Medium (bps)	2019 High (bps)	2020 Medium (bps)	2020 High (bps)	2021 Medium (bps)	2021 High (bps)	Incentives ($1000) 2019 Medium ($1,000)	2019 High ($1,000)	2020 Medium ($1,000)	2020 High ($1,000)	2021 Medium ($1,000)	2021 High ($1,000)
System Efficiency												
Transmission Peak Demand Reduction	40	80	46	93	51	103	$2,383	$4,765	$2,800	$5,599	$3,266	$6,531
FCM Peak Demand Reduction	9	18	15	30	21	42	$527	$1,054	$907	$1,814	$1,351	$2,702
Distributed Energy Resources							$0	$0	$0	$0	$0	$0
Demand Response - Residential	1	1	1	1	1	2	$64	$68	$74	$83	$93	$108
Demand Response - C&I	3	4	5	8	8	12	$162	$239	$306	$470	$504	$769
Electric Heat Initiative	3	5	4	5	4	5	$191	$277	$225	$318	$232	$330
Electric Vehicle Initiative	3	4	3	6	4	7	$152	$245	$199	$338	$265	$467
Behind-the-Meter Storage	1	3	2	3	2	4	$78	$157	$104	$208	$137	$273
Utility-Scale Storage	3	7	6	12	9	17	$194	$389	$358	$716	$545	$1,090
Non-Wires Alternatives	2	4	3	6	4	8	$108	$215	$167	$334	$241	$482
Existing Energy Efficiency	105	105	90	90	86	86	$6,247	$6,247	$5,455	$5,455	$5,455	$5,455
PST Support Services	-	-	-	-	-	-	$0	$0	$0	$0	$0	$0
Low-Income: participation in PST initiatives	2	3	2	3	2	3	$119	$178	$121	$182	$127	$191
Low-Income: participation in LI rate	2	3	2	3	2	3	$119	$178	$121	$182	$127	$191
Data Access	1	#VALUE!	-	-	-	-	$59	#VALUE!	$0	$0	$0	$0
Peak Demand Forecasting (one-year)	1	#VALUE!	-	-	-	-	$59	#VALUE!	$0	$0	$0	$0
AMI Capabilities (2022)												
Subtotal Existing PIMs	105	105	90	90	86	86						
Subtotal New PIMs	71	#VALUE!	89	169	108	206	$4,216	#VALUE!	$5,382	$10,244	$6,888	$13,132
Total PIMs	176	#VALUE!	179	259	194	292						
	16	27	24	41	32	55						
	6	#VALUE!	4	6	4	6						

Info for Charts	Net Benefits Med	Net Benefits High	Basis Pts Med	Basis Pts High
Trans Peak	$6,531	$13,062	51	103
FCM Peak	$2,702	$5,405	21	42
DR: Res	$59	$88	1	2
DR: C&I	$881	$1,410	8	12
Elect. Heat	$337	$405	4	5
Elect. Vehicles	$276	$551	4	7
BTM Storage	$146	$292	2	4
Utility-Scale Storage	$963	$1,926	9	17
NWAs	$354	$709	4	8
Energy Efficiency	#######	######	86	86
Total New PIMs	$12,250	$23,848	104	200









OUTCOMES
Division Proposal

Performance Incentive Mechanism	Target Units	FCM Savings (MW-yr)						Transmission Savings (MW-yr)					
		2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
		Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency													
Transmission Peak Demand Reduction	MW below baseline	0	0	0	0	0	0	10	21	12	23	13	26
FCM Peak Demand Reduction	MW below baseline	15	29	15	31	16	32	1	2	1	3	1	3
Distributed Energy Resources													
Demand Response - Residential	Incremental MW	1	2	3	5	6	9	0	1	1	1	2	2
Demand Response - C&I	Incremental MW	8	14	18	30	30	48	2	4	5	8	8	12
Electric Heat Initiative	Incremental Tonnes CO2	0	0	0	0	0	0	0	0	0	0	0	0
Electric Vehicle Initiative	Incremental Tonnes CO2	0	0	0	0	0	0	0	0	0	0	0	0
Behind-the-Meter Storage	Incremental MW	1	2	2	3	2	5	0	1	1	1	1	2
Utility-Scale Storage	Incremental MW	3	5	5	11	8	16	3	5	5	11	8	16
Non-Wires Alternatives	Incremental MW	2	4	4	7	5	11	1	2	2	4	3	5
Existing Energy Efficiency	Incremental MW	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services													
Low-Income: participation in PST initiatives	% LI cust in initiative	0	0	0	0	0	0	0	0	0	0	0	0
Low-Income: participation in LI rate	% LI cust in initiative	0	0	0	0	0	0	0	0	0	0	0	0
Provision of Customer Information	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand Forecasting (one-year)	0	0	0	0	0	0	0	0	0	0	0	0	0
AMI Capabilities (2022)	# cust with TVR	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal New PIMs	-	**29**	**56**	**47**	**87**	**68**	**121**	**18**	**35**	**26**	**50**	**35**	**66**

Performance Incentive Mechanism	Target Units	Distribution Savings (MW-yr)						Energy Avg (MWh)					
		2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
		Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency													
Transmission Peak Demand Reduction	MW below baseline	6	11	6	13	7	14	0	0	0	0	0	0
FCM Peak Demand Reduction	MW below baseline	3	6	3	6	3	6	0	0	0	0	0	0
Distributed Energy Resources													
Demand Response - Residential	Incremental MW	1	2	2	4	5	7	0	0	0	0	0	0
Demand Response - C&I	Incremental MW	6	11	14	24	24	38	0	0	0	0	0	0
Electric Heat Initiative	Incremental Tonnes CO2	0	0	0	0	0	0	0	0	0	0	0	0
Electric Vehicle Initiative	Incremental Tonnes CO2	0	0	0	0	0	0	0	0	0	0	0	0
Behind-the-Meter Storage	Incremental MW	0	1	1	2	1	2	0	0	0	0	0	0
Utility-Scale Storage	Incremental MW	3	5	5	11	8	16	0	0	0	0	0	0
Non-Wires Alternatives	Incremental MW	3	6	6	12	9	18	0	0	0	0	0	0
Existing Energy Efficiency	Incremental MW	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services													
Low-Income: participation in PST initiatives	% LI cust in initiative	0	0	0	0	0	0	0	0	0	0	0	0
Low-Income: participation in LI rate	% LI cust in initiative	0	0	0	0	0	0	0	0	0	0	0	0
Provision of Customer Information	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand Forecasting (one-year)	0	0	0	0	0	0	0	0	0	0	0	0	0
AMI Capabilities (2022)	# cust with TVR	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal New PIMs	-	**22**	**42**	**38**	**71**	**57**	**103**	-	-	-	-	-	-

Performance Incentive Mechanism	Target Units	Energy Peak (MWh)						GHG (Tons)					
		2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
		Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency													
Transmission Peak Demand Reduction	MW below baseline	0	0	0	0	0	0	0	0	0	0	0	0
FCM Peak Demand Reduction	MW below baseline	15	29	15	31	16	32	0	0	0	0	0	0
Distributed Energy Resources													
Demand Response - Residential	Incremental MW	1	2	3	5	6	9	0	0	0	0	0	0
Demand Response - C&I	Incremental MW	8	14	18	30	30	48	0	0	0	0	0	0
Electric Heat Initiative	Incremental Tonnes CO2	0	0	0	0	0	0	0	0	0	0	0	0
Electric Vehicle Initiative	Incremental Tonnes CO2	0	0	0	0	0	0	557	1,114	1,314	2,625	2,339	4,676
Behind-the-Meter Storage	Incremental MW	1	2	2	4	3	6	0	0	0	0	0	0
Utility-Scale Storage	Incremental MW	3	6	6	12	9	18	0	0	0	0	0	0
Non-Wires Alternatives	Incremental MW	0	0	0	0	0	0	0	0	0	0	0	0
Existing Energy Efficiency	Incremental MW	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services													
Low-Income: participation in PST initiatives	% LI cust in initiative	0	0	0	0	0	0	0	0	0	0	0	0
Low-Income: participation in LI rate	% LI cust in initiative	0	0	0	0	0	0	0	0	0	0	0	0
Provision of Customer Information	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand Forecasting (one-year)	0	0	0	0	0	0	0	0	0	0	0	0	0
AMI Capabilities (2022)	# cust with TVR	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal New PIMs	-	**28**	**53**	**44**	**82**	**64**	**113**	**557**	**1,114**	**1,314**	**2,625**	**2,339**	**4,676**

INCENTIVES
Division Proposal

Performance Incentive Mechanism	Bps or Shared Savings	% to Company	Assumed Costs as % of Benefits	BCR	Target Units	Incentive for Quantified Net Benefits 2019 Medium	2019 High	2020 Medium	2020 High	2021 Medium	2021 High	Unquantified Benefits
System Efficiency												
Transmission Peak Demand Reduction	bps	50%	0%		MW below baseline	40	80	46	93	51	103	
FCM Peak Demand Reduction	bps	50%	0%		MW below baseline	9	18	15	30	21	42	
Distributed Energy Resources						-	-	-	-	-	-	
Demand Response - Residential	shared savings	50%	90%	1.11	Incremental MW	0	0	0	0	0	1	R&R; Mkt Trnsf
Demand Response - C&I	shared savings	50%	70%	1.43	Incremental MW	2	3	4	7	7	11	R&R; Mkt Trnsf
Electric Heat Initiative	shared savings	50%	71%	1.40	Incremental Tonnes C(	2	3	3	3	3	3	R&R; Mkt Trnsf; LI
Electric Vehicle Initiative	bps	50%	80%	1.25	Incremental Tonnes C(	1	1	1	3	2	4	Mkt Trnsf
Behind-the-Meter Storage	shared savings	50%	90%	1.11	Incremental MW	0	1	1	1	1	2	R&R; Mkt Trnsf
Utility-Scale Storage	shared savings	50%	90%	1.11	Incremental MW	2	5	5	10	8	15	R&R; Mkt Trnsf
Non-Wires Alternatives	shared savings	50%	90%	1.11	Incremental MW	1	2	2	4	3	6	Mkt Trnsf
Existing Energy Efficiency		5%	33%	3.03	Incremental MW	264	264	283	283	269	269	
PST Support Services						0	0	0	0	0	0	
Low-Income: participation in PST initiatives	bps				% LI cust in initiative	0	0	0	0	0	0	LI benefits
Low-Income: participation in LI rate	bps				% LI cust in initiative	0	0	0	0	0	0	LI benefits
Provision of Customer Information	bps				0	0	0	0	0	0	0	PST Support
Peak Demand Forecasting (one-year)	bps				0	0	0	0	0	0	0	PST Support
AMI Capabilities (2022)					# cust with TVR	0	0	0	0	0	0	
Subtotal Existing PIMs						264	264	283	283	269	269	
Subtotal New PIMs						57	112	77	150	96	187	
Total PIMs						321	375	360	433	366	457	

Performance Incentive Mechanism	Additional Bps for Unquantified Benefits 2019 Medium (bps)	2019 High (bps)	2020 Medium (bps)	2020 High (bps)	2021 Medium (bps)	2021 High (bps)	Incentives (Basis Points) 2019 Medium (bps)	2019 High (bps)	2020 Medium (bps)	2020 High (bps)	2021 Medium (bps)	2021 High (bps)	Incentives ($1000) 2019 Medium ($1,000)	2019 High ($1,000)	2020 Medium ($1,000)	2020 High ($1,000)	2021 Medium ($1,000)	2021 High ($1,000)
System Efficiency																		
Transmission Peak Demand Reduction	-	-	-	-	-	-	40	80	46	93	51	103	$2,383	$4,765	$2,800	$5,599	$3,266	$6,531
FCM Peak Demand Reduction	-	-	-	-	-	-	9	18	15	30	21	42	$527	$1,054	$907	$1,814	$1,351	$2,702
Distributed Energy Resources	-	-	-	-	-	-	-	-	-	-	-	-	$0	$0	$0	$0	$0	$0
Demand Response - Residential	1	1	1	1	1	1	1	1	1	1	1	2	$64	$68	$74	$83	$93	$108
Demand Response - C&I	1	1	1	1	1	1	3	4	5	8	8	12	$162	$239	$306	$470	$504	$769
Electric Heat Initiative	1	2	1	2	1	2	3	5	4	5	4	5	$191	$277	$225	$318	$232	$330
Electric Vehicle Initiative	2	3	2	3	2	3	3	4	3	6	4	7	$152	$245	$199	$338	$265	$467
Behind-the-Meter Storage	1	2	1	2	1	2	1	3	2	3	2	4	$78	$157	$104	$208	$137	$273
Utility-Scale Storage	1	2	1	2	1	2	3	7	6	12	9	17	$194	$389	$358	$716	$545	$1,090
Non-Wires Alternatives	1	2	1	2	1	2	2	4	3	6	4	8	$108	$215	$167	$334	$241	$482
Existing Energy Efficiency	-	-	-	-	-	-	105	105	90	90	86	86	$6,247	$6,247	$5,455	$5,455	$5,455	$5,455
PST Support Services	-	-	-	-	-	-	-	-	-	-	-	-	$0	$0	$0	$0	$0	$0
Low-Income: participation in PST initiatives	2	3	2	3	2	3	2	3	2	3	2	3	$119	$178	$121	$182	$127	$191
Low-Income: participation in LI rate	2	3	2	3	2	3	2	3	2	3	2	3	$119	$178	$121	$182	$127	$191
Provision of Customer Information	1	-	-	-	-	-	1	#VALUE!	-	-	-	-	$59	#VALUE!	$0	$0	$0	$0
Peak Demand Forecasting (one-year)	1	-	-	-	-	-	1	#VALUE!	-	-	-	-	$59	#VALUE!	$0	$0	$0	$0
AMI Capabilities (2022)	-	-	-	-	-	-	-	-	-	-	-	-	$0	$0	$0	$0	$0	-
Subtotal Existing PIMs							105	105	90	90	86	86						
Subtotal New PIMs							71	#VALUE!	89	169	108	206	$4,216	#VALUE!	$5,382	$10,244	$6,888	$13,132
Total PIMs							176	#VALUE!	179	259	194	292						

System Efficiency	49	98	61	122	73	145
New DERs	16	27	24	41	32	55
Other	6	#VALUE!	4	6	4	6

BENEFITS OF DIVISION PROPOSAL

Avoided Costs/Unit

Performance Incentive Mechanism	Assumed Measure Life (yrs)	FCM Benefits ($/MW-yr)						Transmission Peak Benefits ($/MW-yr)					
Lookup Cells		FCM	FCM	FCM	FCM	FCM	FCM	Transmissior	Transmissior	Transmissior	Transmissior	Transmissior	Transmissior
Lookup Cells		'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex
Lookup Cells		2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High	2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High
		2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
		Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency													
Transmission Peak Demand Reduction	3	$0	$0	$44,431	$44,431	$92,027	$92,027	$339,949	$339,949	$361,643	$361,643	$383,905	$383,905
FCM Peak Demand Reduction	3	$0	$0	$44,431	$44,431	$92,027	$92,027	$339,949	$339,949	$361,643	$361,643	$383,905	$383,905
Distributed Energy Resources													
Demand Response - Residential	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
Demand Response - C&I	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
Electric Heat Initiative	25	$779,476	$779,476	$822,347	$822,347	$867,576	$867,576	#########	#########	#########	#########	#########	#########
Electric Vehicle Initiative	10	$301,924	$301,924	$375,417	$375,417	$449,931	$449,931	#########	#########	#########	#########	#########	#########
Behind-the-Meter Storage	5	$82,682	$82,682	$132,480	$132,480	$186,397	$186,397	$570,558	$570,558	$605,655	$605,655	$641,537	$641,537
Utility-Scale Storage	5	$82,682	$82,682	$132,480	$132,480	$186,397	$186,397	$570,558	$570,558	$605,655	$605,655	$641,537	$641,537
Non-Wires Alternatives	3	$0	$0	$44,431	$44,431	$92,027	$92,027	$339,949	$339,949	$361,643	$361,643	$383,905	$383,905
Existing Energy Efficiency	12	$404,241	$404,241	$480,648	$480,648	$562,516	$562,516	#########	#########	#########	#########	#########	#########
PST Support Services													
Low-Income: participation in PST initiatives	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
Low-Income: participation in LI rate	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
Data Access	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
Peak Demand Forecasting (one-year)	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
AMI Capabilities (2022)	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232

Performance Incentive Mechanism	Distribution Benefits ($/MW-yr)						Energy Peak Benefits ($/MW)					
Lookup Cells	Distribution	Distribution	Distribution	Distribution	Distribution	Distribution	Energy Peak	Energy Peak	Energy Peak	Energy Peak	Energy Peak	Energy Peak
Lookup Cells	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex
Lookup Cells	2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High	2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency												
Transmission Peak Demand Reduction	$218,354	$218,354	$219,113	$219,113	$223,419	$223,419	$200	$200	$197	$197	$193	$193
FCM Peak Demand Reduction	$218,354	$218,354	$219,113	$219,113	$223,419	$223,419	$200	$200	$197	$197	$193	$193
Distributed Energy Resources												
Demand Response - Residential	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
Demand Response - C&I	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
Electric Heat Initiative	#########	#########	#########	#########	#########	#########	$1,170	$1,170	$1,159	$1,159	$1,145	$1,145
Electric Vehicle Initiative	$639,855	$639,855	$655,520	$655,520	$683,937	$683,937	$598	$598	$617	$617	$637	$637
Behind-the-Meter Storage	$344,906	$344,906	$363,102	$363,102	$360,623	$360,623	$314	$314	$316	$316	$319	$319
Utility-Scale Storage	$344,906	$344,906	$363,102	$363,102	$360,623	$360,623	$314	$314	$316	$316	$319	$319
Non-Wires Alternatives	$218,354	$218,354	$219,113	$219,113	$223,419	$223,419	$200	$200	$197	$197	$193	$193
Existing Energy Efficiency												
PST Support Services												
Low-Income: participation in PST initiatives	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
Low-Income: participation in LI rate	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
Data Access	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
Peak Demand Forecasting (one-year)	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
AMI Capabilities (2022)	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66

Performance Incentive Mechanism	GHG Benefits ($/MWh)						GHG ($/Tonne)						Initiative Net Benefits ($/tonne over study period)					
Lookup Cells	GHG MWh	GHG MWh	GHG MWh	GHG MWh	GHG MWh	GHG MWh	GHG tons	GHG tons	GHG tons	GHG tons	GHG tons	GHG tons						
Lookup Cells	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Exhibit 4_Docket 4770.xlsx]Global Inputs'!H8						
Lookup Cells	2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High	2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High	2019Medium	2019High	2020Medium	2020High	2021Medium	2021High
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency																		
Transmission Peak Demand Reduction	$125	$125	$125	$125	$124	$124	$220	$220	$220	$220	$218	$218						
FCM Peak Demand Reduction	$125	$125	$125	$125	$124	$124	$220	$220	$220	$220	$218	$218						
Distributed Energy Resources																		
Demand Response - Residential	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
Demand Response - C&I	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
Electric Heat Initiative	$660	$660	$668	$668	$676	$676	$1,164	$1,164	$1,177	$1,177	$1,191	$1,191	$1,984	$1,984	$1,984	$1,984	$1,984	$1,984
Electric Vehicle Initiative	$340	$340	$338	$338	$334	$334	$600	$600	$596	$596	$590	$590						
Behind-the-Meter Storage	$196	$196	$196	$196	$194	$194	$346	$346	$345	$345	$342	$342						
Utility-Scale Storage	$196	$196	$196	$196	$194	$194	$346	$346	$345	$345	$342	$342						
Non-Wires Alternatives	$125	$125	$125	$125	$124	$124	$220	$220	$220	$220	$218	$218						
Existing Energy Efficiency																		
PST Support Services																		
Low-Income: participation in PST initiatives	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
Low-Income: participation in LI rate	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
Data Access	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
Peak Demand Forecasting (one-year)	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
AMI Capabilities (2022)	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						

Outcomes

Performance Incentive Mechanism	Target Units	Convert Tx Months of Savings to Years	FCM Peak Coincidence	Transmission Peak Coincidence	Distribution Peak Coincidence	FCM Savings (MW-yr)						Transmission Savings (MW-yr)					
						2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
						Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency																	
Transmission Peak Demand Reduction	MW below baseline	9%	0%	100%	5%	0	0	0	0	0	0	10	21	12	23	13	26
FCM Peak Demand Reduction	MW below baseline	100%	100%	8%	20%	15	29	15	31	16	32	1	2	1	3	1	3
Distributed Energy Resources																	
Demand Response - Residential	Incremental MW	100%	100%	25%	80%	1	2	3	5	6	9	0	1	1	1	2	2
Demand Response - C&I	Incremental MW	100%	100%	25%	80%	8	14	18	30	30	48	2	4	5	8	8	12
Electric Heat Initiative	cremental Tonnes CO2	100%	0%	0%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electric Vehicle Initiative	cremental Tonnes CO2	100%	0%	0%	0%	0	0	0	0	0	0	0	0	0	0	0	0
Behind-the-Meter Storage	Incremental MW	100%	80%	30%	40%	1	2	2	3	2	5	0	1	1	1	1	2
Utility-Scale Storage	Incremental MW	100%	90%	90%	90%	3	5	5	11	8	16	3	5	5	11	8	16
Non-Wires Alternatives	Incremental MW	100%	60%	30%	100%	2	4	4	7	5	11	1	2	2	4	3	5
Existing Energy Efficiency	Incremental MW	100%				0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services																	
Low-Income: participation in PST initiatives	% LI cust in initiative	100%															
Low-Income: participation in LI rate	% LI cust in initiative	100%															
Data Access		100%															
Peak Demand Forecasting (one-year)		100%															
AMI Capabilities (2022)	# cust with TVR	100%															
Subtotal Existing PIMs																	
Subtotal New PIMs																	
Total PIMs																	

Performance Incentive Mechanism	Distribution Savings (MW-yr)						Energy Peak (MWh)					
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency												
Transmission Peak Demand Reduction	6	11	6	13	7	14						
FCM Peak Demand Reduction	3	6	3	6	3	6	15	29	15	31	16	32
Distributed Energy Resources												
Demand Response - Residential	1	2	2	4	5	7	1	2	3	5	6	9
Demand Response - C&I	6	11	14	24	24	38	8	14	18	30	30	48
Electric Heat Initiative	0.0	0.0	0.0	0.0	0.0	0.0						
Electric Vehicle Initiative	0	0	0	0	0	0						
Behind-the-Meter Storage	0	1	1	2	1	2	1	2	2	4	3	6
Utility-Scale Storage	3	5	5	11	8	16	3	6	6	12	9	18
Non-Wires Alternatives	3	6	6	12	9	18						
Existing Energy Efficiency	0	0	0	0	0	0						
PST Support Services												
Low-Income: participation in PST initiatives												
Low-Income: participation in LI rate												
Data Access												
Peak Demand Forecasting (one-year)												
AMI Capabilities (2022)												
Subtotal Existing PIMs												
Subtotal New PIMs												
Total PIMs												

Performance Incentive Mechanism	GHG (MWh)						GHG (Tonnes)						Initiative (tonnes)					
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency																		
Transmission Peak Demand Reduction																		
FCM Peak Demand Reduction																		
Distributed Energy Resources																		
Demand Response - Residential																		
Demand Response - C&I																		
Electric Heat Initiative													464.00	556.00	580.00	696.00	595.00	714.00
Electric Vehicle Initiative							557	1,114	1,314	2,625	2,339	4,676						
Behind-the-Meter Storage																		
Utility-Scale Storage																		
Non-Wires Alternatives																		
Existing Energy Efficiency																		
PST Support Services																		
Low-Income: participation in PST initiatives																		
Low-Income: participation in LI rate																		
Data Access																		
Peak Demand Forecasting (one-year)																		
AMI Capabilities (2022)																		
Subtotal Existing PIMs																		
Subtotal New PIMs																		
Total PIMs																		

Calculate $ Value of Outcomes

Performance Incentive Mechanism	FCM Benefits ($)						Transmission Benefits ($)					
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency												
Transmission Peak Demand Reduction	0	0	0	0	0	0	3,521,349	7,042,698	4,199,652	8,399,305	4,947,561	9,895,121
FCM Peak Demand Reduction	0	0	679,796	1,359,591	1,472,432	2,944,864	413,605	827,210	461,095	922,190	511,874	1,023,747
Distributed Energy Resources												
Demand Response - Residential	0	0	0	0	0	0	28,057	56,114	89,735	149,559	190,848	286,271
Demand Response - C&I	0	0	0	0	0	0	224,456	392,798	538,412	897,353	954,238	1,526,781
Electric Heat Initiative	0	0	0	0	0	0	0	0	0	0	0	0
Electric Vehicle Initiative	0	0	0	0	0	0	0	0	0	0	0	0
Behind-the-Meter Storage	66,146	132,291	211,967	423,935	447,354	894,708	171,167	342,335	363,393	726,786	577,383	1,154,766
Utility-Scale Storage	223,241	446,482	715,390	1,430,780	1,509,820	3,019,639	1,540,507	3,081,014	3,270,538	6,541,076	5,196,448	#########
Non-Wires Alternatives	0	0	159,952	319,904	496,946	993,892	305,954	611,909	650,957	1,301,915	1,036,544	2,073,089
Existing Energy Efficiency	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services												
Low-Income: participation in PST initiatives												
Low-Income: participation in LI rate												
Data Access												
Peak Demand Forecasting (one-year)												
AMI Capabilities (2022)												
Subtotal New PIMs	**289387**											

Performance Incentive Mechanism	Distribution Benefits ($)						Energy Peak ($)					
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency												
Transmission Peak Demand Reduction	1,243,998	2,487,996	1,399,469	2,798,939	1,583,613	3,167,226	0	0	0	0	0	0
FCM Peak Demand Reduction	637,595	1,275,190	670,485	1,340,969	714,939	1,429,879	2,927	5,853	3,014	6,028	3,085	6,169
Distributed Energy Resources												
Demand Response - Residential	57,501	115,002	183,061	305,102	396,303	594,455	72	143	220	366	397	595
Demand Response - C&I	460,008	805,013	1,098,369	1,830,614	1,981,516	3,170,425	573	1,002	1,318	2,197	1,985	3,176
Electric Heat Initiative	0	0	0	0	0	0	0	0	0	0	0	0
Electric Vehicle Initiative	0	0	0	0	0	0	0	0	0	0	0	0
Behind-the-Meter Storage	137,963	275,925	290,482	580,964	432,748	865,496	314	628	632	1,264	958	1,916
Utility-Scale Storage	931,247	1,862,494	1,960,753	3,921,505	2,921,049	5,842,098	943	1,885	1,895	3,791	2,874	5,748
Non-Wires Alternatives	655,063	1,310,126	1,314,676	2,629,352	2,010,767	4,021,534	0	0	0	0	0	0
Existing Energy Efficiency	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services												
Low-Income: participation in PST initiatives												
Low-Income: participation in LI rate												
Data Access												
Peak Demand Forecasting (one-year)												
AMI Capabilities (2022)												
Subtotal New PIMs												

Performance Incentive Mechanism	GHG Benefits ($)						GHG Benefits ($)						Initiative Net Benefits ($)					
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency																		
Transmission Peak Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FCM Peak Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distributed Energy Resources																		
Demand Response - Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response - C&I	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Heat Initiative	0	0	0	0	0	0	0	0	0	0	0	0	920,558	1,103,083	1,150,698	1,380,838	1,180,457	1,416,549
Electric Vehicle Initiative	0	0	0	0	0	0	334,226	668,452	782,659	1,564,038	1,379,183	2,757,099	0	0	0	0	0	0
Behind-the-Meter Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Utility-Scale Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Wires Alternatives	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Energy Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services																		
Low-Income: participation in PST initiatives																		
Low-Income: participation in LI rate																		
Data Access																		
Peak Demand Forecasting (one-year)																		
AMI Capabilities (2022)																		
Subtotal New PIMs																		

Performance Incentive Mechanism	Benefits							
	2019	2019	2020	2020	2021	2021	2019-21 Cumulative	
	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency								
Transmission Peak Demand Reduction	$4,765,347	$9,530,693	$5,599,122	$11,198,244	$6,531,173	$13,062,347	$16,895,642	$33,791,284
FCM Peak Demand Reduction	$1,054,126	$2,108,253	$1,814,389	$3,628,778	$2,702,330	$5,404,660	$5,570,845	$11,141,691
Distributed Energy Resources								
Demand Response - Residential	$85,630	$171,259	$273,016	$455,027	$587,548	$881,322	$946,194	$1,507,608
Demand Response - C&I	$685,036	$1,198,814	$1,638,099	$2,730,164	$2,937,739	$4,700,382	$5,260,874	$8,629,360
Electric Heat Initiative	$920,558	$1,103,083	$1,150,698	$1,380,838	$1,180,457	$1,416,549	$3,251,714	$3,900,469
Electric Vehicle Initiative	$334,226	$668,452	$782,659	$1,564,038	$1,379,183	$2,757,099	$2,496,069	$4,989,590
Behind-the-Meter Storage	$375,590	$751,179	$866,474	$1,732,948	$1,458,443	$2,916,886	$2,700,507	$5,401,014
Utility-Scale Storage	$2,695,938	$5,391,876	$5,948,576	$11,897,152	$9,630,191	$19,260,381	$18,274,704	$36,549,409
Non-Wires Alternatives	$961,017	$1,922,035	$2,125,585	$4,251,170	$3,544,257	$7,088,515	$6,630,860	$13,261,720
Existing Energy Efficiency	$0	$0	$0	$0	$0	$0	$0	$0
PST Support Services								
Low-Income: participation in PST initiatives	$0	$0	$0	$0	$0	$0	$0	$0
Low-Income: participation in LI rate	$0	$0	$0	$0	$0	$0	$0	
Data Access	$0	$0	$0	$0	$0	$0	$0	$0
Peak Demand Forecasting (one-year)	$0	$0	$0	$0	$0	$0	$0	$0
AMI Capabilities (2022)	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal New PIMs	**$289,387**	**$0**	**$0**	**$0**	**$0**	**$0**	**$62,027,409**	

Discount Rate	5.50%
Inflation	2.00%

EVs		
EV Avoided Emissions		
Wt Avg Tonnes/yr/vehicle	2.15	*Attachment DIV 1-1-3, Tab 5*

Exclude deadband MW in benefit calcs		% of Standard Error to exclude:	50%		
			2019	2020	2021
Transmission Deadband	(MW)	Standard Error from Synapse Predictions	114	128	142
FCM Deadband	(MW)	Standard Error for Company Predictions	14.6	15.3	16

Outcomes

		Lookup Cells	Incremental Outcomes less Deadband						Cumulative Outcomes less Deadband					
									2019Medium	*2019High*	*2020Medium*	*2020High*	*2021Medium*	*2021High*
			2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
Performance Incentive Mechanism	**Outcome Units**	**Deadband**	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency														
Transmission Peak Demand Reduction	MW below baseline	Transmission Deadba	114	228	128	255	142	284	114	228	128	255	142	284
FCM Peak Demand Reduction	MW below baseline	FCM Deadband	15	29	15	31	16	32	15	29	15	31	16	32
Distributed Energy Resources			0	0	0	0	0	0	0	0	0	0	0	0
Demand Response - Residential	Incremental MW		1	2	2	3	3	4	1	2	3	5	6	9
Demand Response - C&I	Incremental MW		8	14	10	16	12	18	8	14	18	30	30	48
Electric Heat Initiative	Incremental Tonnes CO2		464.0	556.0	580.0	696.0	595.0	714.0	464.0	556.0	1044.0	1252.0	1639.0	1966.0
Electric Vehicle Initiative	Incremental Tonnes CO2		557	1,114	757	1,511	1,026	2,051	557	1,114	1,314	2,625	2,339	4,676
Behind-the-Meter Storage	Incremental MW		1	2	1	2	1	2	1	2	2	4	3	6
Utility-Scale Storage	Incremental MW		3	6	3	6	3	6	3	6	6	12	9	18
Non-Wires Alternatives	Incremental MW		3	6	3	6	3	6	3	6	6	12	9	18
Existing Energy Efficiency	Incremental MW		30	37	35	38	34	38	30	37	65	75	99	113
PST Support Services			0	0	0	0	0	0	0	0	0	0	0	0
Low-Income: participation in PST initiatives	% LI cust in initiative		5	10	5	10	5	10	5	10	5	10	5	10
Low-Income: participation in LI rate	% LI cust in initiative		4	8	4	8	4	8	4	8	4	8	4	8
Data Access			Plan --	--	--	--	--	--	Plan --	--	--	--	--	--
Peak Demand Forecasting (one-year)			Report --	--	--	--	--	--	Report --	--	--	--	--	--
AMI Capabilities (2022)	# cust with TVR		-- --	--	--	--	--	--	-- --	--	--	--	--	--

Peak Demand Forecast

	Units	Year	MW	Source
Peak Demand	MW	2019	1,691	*National Grid Forecast Attachment DIV 8-5*
		2020	1,679	*National Grid Forecast Attachment DIV 8-5*
		2021	1,672	*National Grid Forecast Attachment DIV 8-5*
		2022	1,668	*National Grid Forecast Attachment DIV 8-5*

FCM		Source/Notes	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
($/MW-yr)	**Ngrid BCA**	3; Attachment DIV 8-6; AESC 2015 Update - Appendi	$0	$0	$0	$151,748	$145,443	$154,497	$173,685	$193,939	$214,296	$235,795	$259,373	$290,551	$308,170	$314,333	$320,620	$327,032	$333,573	$340,244	$347,049	$353,990
	Daymark	Daymark Email Rec'd 3/16/18	$0	$0	$0	$55,042	$55,936	$62,393	$64,297	$69,950	$75,749	$84,529	$102,516	$97,070	$108,661	$111,185	$114,424	$117,749	$121,160	$124,661	$128,254	$131,940
	Ngrid EE Screening Tool																					
	Synapse/Division		$0	$0	$0	$55,042	$55,936	$62,393	$64,297	$69,950	$75,749	$84,529	$102,516	$97,070	$108,661	$111,185	$114,424	$117,749	$121,160	$124,661	$128,254	$131,940

Transmission			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
($/MW-yr)	**Ngrid BCA**	Attachment DIV 1-36-1	$114,808	$117,104	$119,446																	
	Daymark	Daymark Email Rec'd 3/16/18	$124,913	$133,170	$141,612	$150,390	$159,312	$168,380	$177,593	$186,950	$196,453	$206,100	$215,893	$225,830	$235,913	$246,141	$256,513	$267,031	$277,693	$288,501	$299,454	$310,551
	Ngrid EE Screening Tool																					
	Synapse/Division		$124,913	$133,170	$141,612	$150,390	$159,312	$168,380	$177,593	$186,950	$196,453	$206,100	$215,893	$225,830	$235,913	$246,141	$256,513	$267,031	$277,693	$288,501	$299,454	$310,551

Distribution		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
($/MW-yr)	**Ngrid BCA**												
	Daymark												
	Ngrid EE Screening Tool	$80,000	$84,897	$91,895	$80,001	$90,094	$103,490	$80,002	$95,610	$116,548	$80,003	$101,463	$131,253
	Synapse/Division	$80,000	$84,897	$91,895	$80,001	$90,094	$103,490	$80,002	$95,610	$116,548	$80,003	$101,463	$131,253

Distribution		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
($/MW-yr)	**Ngrid BCA**																		
	Daymark																		
	Ngrid EE Screening Tool	$80,004	$107,675	$147,814	$80,005	$114,267	$166,465	$80,006	$121,262	$187,469	$80,007	$128,686	$211,123	$80,008	$136,565	$237,762	$80,009	$144,925	$267,762
	Synapse/Division	$80,004	$107,675	$147,814	$80,005	$114,267	$166,465	$80,006	$121,262	$187,469	$80,007	$128,686	$211,123	$80,008	$136,565	$237,762	$80,009	$144,925	$267,762

Energy Avg		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
($/MWh)	**Ngrid BCA**	$33	$37	$42	$46	$47	$51	$53	$56	$57	$57	$60	$61
	Daymark												
	Ngrid EE Screening Tool												
	Synapse/Division	$33	$37	$42	$46	$47	$51	$53	$56	$57	$57	$60	$61

Energy Avg		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
($/MWh)	**Ngrid BCA**	$63	$65	$67	$69	$71	$73	$75	$78	$80	$82	$85	$87	$90	$93	$95	$98	$101	$104
	Daymark																		
	Ngrid EE Screening Tool																		
	Synapse/Division	$63	$65	$67	$69	$71	$73	$75	$78	$80	$82	$85	$87	$90	$93	$95	$98	$101	$104

Energy Peak			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
($/MWh)	**Ngrid BCA**													
	Daymark	Daymark Email Rec'd 3/16/18	$80	$82	$74	$76	$77	$83	$87	$94	$96	$101	$110	$116
	Ngrid EE Screening Tool													
	Synapse/Division		$80	$82	$74	$76	$77	$83	$87	$94	$96	$101	$110	$116

Energy Peak		2031	2032	2033	2034	2035	2036	2037	2038										
($/MWh)	**Ngrid BCA**																		
	Daymark	$121	$128	$136	$142	$151	$156	$166	$174										
	Ngrid EE Screening Tool																		
	Synapse/Division	$121	$128	$136	$142	$151	$156	$166	$174										

GHG MWh		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
($/MWh)	**Ngrid BCA**	$49	$49	$49	$48	$48	$47	$47	$46	$46	$45	$45	$44
	Daymark	na											
	Ngrid EE Screening Tool	---											
	Synapse/Division	$49	$49	$49	$48	$48	$47	$47	$46	$46	$45	$45	$44

GHG MWh		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
($/MWh)	**Ngrid BCA**	$54	$55	$56	$58	$59	$60	$61	$62	$63	$65	$66	$67	$69	$70	$71	$73	$74	
	Daymark																		
	Ngrid EE Screening Tool																		
	Synapse/Division	$54	$55	$56	$58	$59	$60	$61	$62	$63	$65	$66	$67	$69	$70	$71	$73	$74	$0

GHG tons		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
$/metric tonne	**Ngrid BCA**	$86	$86	$86	$85	$84	$84	$83	$82	$81	$80	$79	$78
	Daymark	na											
	Ngrid EE Screening Tool	---											
	Synapse/Division	$86	$86	$86	$85	$84	$84	$83	$82	$81	$80	$79	$78

GHG tons		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	
$/metric tonne	**Ngrid BCA**	$96	$98	$99	$101	$103	$106	$108	$110	$112	$114	$116	$119	$121	$124	$126	$128	$131	
	Daymark																		
	Ngrid EE Screening Tool																		
	Synapse/Division	$96	$98	$99	$101	$103	$106	$108	$110	$112	$114	$116	$119	$121	$124	$126	$128	$131	

			Basis Points 2019	Basis Points 2020	Basis Points 2021
			2019	2020	2021
Basis Points	Bps	**Ngrid**	$59,493	$60,526	$63,602

Source: RIPDUC_2018_PeakLoadReduction_Summary_v1 (Received from Daymark 3/16/18)

Values calculated for 2.5% peak reduction

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
$/MW Generation Capacity	$ -	$ -	$ -	$ 55,042	$ 55,936	$ 62,393	$ 64,297	$ 69,950	$ 75,749	$ 84,529
$/MW Transmission Capacity	$ 124,913	$ 133,170	$ 141,612	$ 150,390	$ 159,312	$ 168,380	$ 177,593	$ 186,950	$ 196,453	$ 206,100
$/MWh Energy	$ 80	$ 82	$ 74	$ 76	$ 77	$ 83	$ 87	$ 94	$ 96	$ 101

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
$/MW Generation Capacity	$ 102,516	$ 97,070	$ 108,661	$ 111,185	$ 114,424	$ 117,749	$ 121,160	$ 124,661	$ 128,254	$ 131,940
$/MW Transmission Capacity	$ 215,893	$ 225,830	$ 235,913	$ 246,141	$ 256,513	$ 267,031	$ 277,693	$ 288,501	$ 299,454	$ 310,551
$/MWh Energy	$ 110	$ 116	$ 121	$ 128	$ 136	$ 142	$ 151	$ 156	$ 166	$ 174

Source: Attachment DIV-1-1-3

Rhode Island Power Sector Transformation | Benefit-Cost Analysis (BCA) Models | Inputs - General

General assumptions applied to investment categories

Inputs - General

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General Assumptions

Assumption	Value	Unit	Source
Line Losses	8.0%	%	AESC 2015, p. 286. ISO Distribution Losses.
Wholesale Risk Premium (WRP)	9.0%	%	AESC 2015. Appendix B
Distribution Losses	8.0%	%	AESC 2015. Appendix B
Real Discount Rate	1.4%	%	AESC 2015. Appendix B
Percent of Capacity Bid into FCM (%Bid)	75.0%	%	AESC 2015. Appendix B
After-tax WACC	7.5%	%	See email from Josh Nowak
Inflation Rate	2.0%	%	

Emissions Assumptions

Assumption	Value	Unit	Source	Comments
CO2 Grid Emissions Factors	1029	lbs / MWh	http://www.neep.org/sites/default/files/Emission_Factors_Ann	1 short ton = 1 US ton = 2,000 lbs
SO2 Grid Emissions Factor	0.17	lbs / MWh	http://www.neep.org/sites/default/files/Emission_Factors_Ann	1 short ton = 1 US ton = 2,000 lbs
NOX Grid Emissions Factor	0.35	lbs / MWh	http://www.neep.org/sites/default/files/Emission_Factors_Ann	1 short ton = 1 US ton = 2,000 lbs
NE-ISO Off-Peak LMU Marginal CO2 Emission rate	832	lbs / MWh	2015 ISO New England Electric Generator Air Emissions Report, Table 5.3, https://www.iso-ne.com/static-assets/documen	
NE-ISO On-Peak LMU Marginal CO2 Emission rate	891	lbs / MWh	2015 ISO New England Electric Generator Air Emissions Report, Table 5.3, https://www.iso-ne.com/static-assets/documen	

Unit Conversions

Assumption	Value	Unit	Source
Pounds to Tons conversion	0.0005	#	Standard value
kg to pounds conversion	2.2046		
kWh to MWh conversion	1000		

Time Assumptions

Assumption	Unit	Source	Comments	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CO2 Abatement Cost	$ / short ton	2015 AESC. Exhibit 4-7	AESC duration terminated at 2030. Kept same value through 2042	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Embedded Cost in Electric Energy Market Prices	$ / short ton	2015 AESC. Exhibit 4-7	AESC duration terminated at 2030. Projected linear trend through 2042	8.47	9.32	10.16	12.54	14.92	17.30	19.67	22.05	24.43	26.80	29.18	31.56	33.94	20.11	20.12
Non-embedded CO2 Costs (pre-inflation)	$ / short ton	2015 AESC. Exhibit 4-7		91.53	90.68	89.84	87.46	85.08	82.70	80.33	77.95	75.57	73.20	70.82	68.44	66.06	79.89	79.88
Non-embedded CO2 Costs (post-inflation)	$ / short ton	2015 AESC. Exhibit 4-7		93.36	94.34	95.34	94.67	93.94	93.13	92.27	91.33	90.31	89.23	88.06	86.80	85.46	105.41	107.51
Non-embedded CO2 Costs (pre-inflation)	$ / MWh	Calculated		47.09	46.65	46.22	45.00	43.77	42.55	41.33	40.11	38.88	37.66	36.44	35.21	33.99	41.10	41.10
Non-embedded CO2 Costs (post-inflation)	$ / MWh	Calculated		48.03	48.54	49.05	48.71	48.33	47.92	47.47	46.99	46.47	45.91	45.30	44.66	43.97	54.23	55.31

Assumption	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
CO2 Abatement Cost	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Embedded Cost in Electric Energy Market Prices	20.13	20.14	20.15	20.16	20.17	20.18	20.19	20.20	20.21	20.22	20.23	20.24	20.25	20.26	20.27
Non-embedded CO2 Costs (pre-inflation)	79.87	79.86	79.85	79.84	79.83	79.82	79.81	79.80	79.79	79.78	79.77	79.76	79.75	79.74	79.73
Non-embedded CO2 Costs (post-inflation)	109.64	111.82	114.04	116.31	118.62	120.98	123.38	125.84	128.34	130.89	133.49	136.14	138.85	141.61	144.42
Non-embedded CO2 Costs (pre-inflation)	41.09	41.09	41.08	41.08	41.07	41.07	41.06	41.06	41.05	41.05	41.04	41.04	41.03	41.03	41.02
Non-embedded CO2 Costs (post-inflation)	56.41	57.53	58.68	59.84	61.03	62.24	63.48	64.74	66.03	67.34	68.68	70.05	71.44	72.86	74.30

SO2 & NOx Emissions Factors - non-electric fuels

Fuel	Physical Units					Conversion Factors		Short Tons/MMBTU			Source
	Reported Unit	SO2 Constant	S value	SO2	NOx	MMBTU	Short Tons	SO2	NOx	lbs/MMBTU	
Natural Gas	lb/million cuft	0.6	2000	0.6	94	1032	2000	2.907E-07	4.55426E-05	0.000581395	EPA
Propane	lb/thousand gallons	0.1	0.54	0.054	13	91.333	2000	2.9562E-07	7.11681E-05	0.000591243	https://www
Fuel Oil	lb/thousand gallons	142	0.003	42.6	18	138.5	2000	0.00015379	6.49819E-05	0.307581227	https://www

SO2 and NOX - AESC 2015 Update

Source: AESC 2015 Exhibit 4.1. Emission Allowance Prices per Short Ton. AESC notes pulled from SNL Financial.

Year	NOX 2015$	NOX 2017$	SO2 2015$	SO2 2017$
2015	10	10	1.11	1.11
2016	10	10.2	1.11	1.1322
2017	10	10.404	1.11	1.154844
2018	10	10.61208	1.11	1.17794088
2019	10	10.8243216	1.11	1.201499698
2020	10	11.04080803	1.11	1.225529692
2021	10	11.26162419	1.11	1.250040285
2022	10	11.48685668	1.11	1.275041091
2023	10	11.71659381	1.11	1.300541913
2024	10	11.95092569	1.11	1.326552751
2025	10	12.1899442	1.11	1.353083806
2026	10	12.43374308	1.11	1.380145482
2027	10	12.68241795	1.11	1.407748392
2028	10	12.9360663	1.11	1.43590336
2029	10	13.19478763	1.11	1.464621427
2030	10	13.45868338	1.11	1.493913856
2031	10	13.72785705	1.11	1.523792133
2032	10	14.00241419	1.11	1.554267975
2033	10	14.28246248	1.11	1.585353335
2034	10	14.56811173	1.11	1.617060402
2035	10	14.85947396	1.11	1.64940161
2036	10	15.15666344	1.11	1.682389642
2037	10	15.45979671	1.11	1.716037435
2038	10	15.76899264	1.11	1.750358183
2039	10	16.08437249	1.11	1.785365347
2040	10	16.40605994	1.11	1.821072654
2041	10	16.73418114	1.11	1.857494107
2042	10	17.06886477	1.11	1.894643989
2043	10	17.41024206	1.11	1.932536869
2044	10	17.7584469	1.11	1.971187606
2045	10	18.11361584	1.11	2.010611358
2046	10	18.47588816	1.11	2.050823586
2047	10	18.84540592	1.11	2.091840057

NOX & SO2 Costs (pre-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
NOX Cost	10.61208	10.8243216	11.04080803	11.26162419	11.4868567	11.7165938	11.9509257	12.1899442	12.4337431	12.6824179	12.9360663	13.1947876	13.4586834	13.7278571	14.0024142
SO2 Cost	1.17794088	1.2014997	1.225529692	1.250040285	1.27504109	1.30054191	1.32655275	1.35308381	1.38014548	1.40774839	1.43590336	1.46462143	1.49391386	1.52379213	1.55426798

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
NOX Cost	14.2824625	14.5681117	14.859474	15.1566634	15.4597967	15.7689926	16.0843725	16.4060599	16.7341811	17.0688648	17.4102421	17.7584469	18.1136158	18.4758882	18.84541
SO2 Cost	1.58535333	1.6170604	1.64940161	1.68238964	1.71603743	1.75035818	1.78536535	1.82107265	1.85749411	1.89464399	1.93253687	1.97118761	2.01061136	2.05082359	2.09184

NOX & SO2 Costs (post-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
NOX Cost	10.8243216	11.2616242	11.71659381	12.1899442	12.6824179	13.1947876	13.7278571	14.2824625	14.859474	15.4597967	16.0843725	16.7341811	17.4102421	18.1136158	18.8454059
SO2 Cost	1.201499698	1.25004029	1.300541913	1.353083806	1.40774839	1.46462143	1.52379213	1.58535333	1.64940161	1.71603743	1.78536535	1.85749411	1.93253687	2.01061136	2.09184006

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
NOX Cost	19.6067603	20.3988734	21.2229879	22.0803966	22.9724447	23.9005314	24.8661129	25.8707039	26.9158803	28.0032819	29.1346144	30.3116529	31.5362436	32.8103079	34.13584
SO2 Cost	2.1763504	2.26427495	2.35575166	2.45092403	2.54994136	2.65295899	2.76013853	2.87164813	2.98766271	3.10836429	3.2339422	3.36459347	3.50052304	3.64194418	3.789079

Avoided Unit Cost of Electric Capacity

Source: AESC 2015 Update, Appendix B

Period	Unit	Value	Source
2018	$/kW-yr	0	AESC 2015 Update-Appendix B
2019	$/kW-yr	0	AESC 2015 Update-Appendix B
2020	$/kW-yr	0	AESC 2015 Update-Appendix B
2021	$/kW-yr	0	AESC 2015 Update-Appendix B
2022	$/kW-yr	137.4430625	AESC 2015 Update-Appendix B
2023	$/kW-yr	129.149657	AESC 2015 Update-Appendix B
2024	$/kW-yr	134.4992808	AESC 2015 Update-Appendix B
2025	$/kW-yr	148.2384617	AESC 2015 Update-Appendix B
2026	$/kW-yr	162.2792734	AESC 2015 Update-Appendix B
2027	$/kW-yr	175.7974832	AESC 2015 Update-Appendix B
2028	$/kW-yr	189.6410963	AESC 2015 Update-Appendix B
2029	$/kW-yr	204.5142091	AESC 2015 Update-Appendix B
2030	$/kW-yr	224.6053249	AESC 2015 Update-Appendix B
2031	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2032	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2033	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2034	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2035	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2036	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2037	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2038	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2039	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2040	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2041	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2042	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2043	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2044	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2045	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2046	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2047	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Avoided Capacity Cost	-	-	-	-	137.44	129.15	134.50	148.24	162.28	175.80	189.64	204.51	224.61	233.55	233.55
Inflation	2%														
Conversion to MW	1000														
Avoided Capacity Cost	-	-	-	-	151,748.25	145,443.49	#######	#######	#######	#######	#######	#######	#######	#######	#######

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Avoided Capacity Cost	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55
Inflation															
Conversion to MW															
Avoided Capacity Cost	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######

Avoided Unit Cost of Energy

Source: AESC 2015 Update, Appendix B

Period	Units	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric Heat Weighted Avg.	Simple Average	$/MWh	Year
2018	$/kWh	0.042948462	0.036876354	0.028704835	0.02178498	0.032578658	0.032578658	32.58	2018
2019	$/kWh	0.046553286	0.04066292	0.033877957	0.026867315	0.03699037	0.03699037	36.99	2019
2020	$/kWh	0.050901503	0.043353232	0.042024216	0.030786197	0.041766287	0.041766287	41.77	2020
2021	$/kWh	0.055575249	0.047862525	0.044949693	0.034145396	0.045633216	0.045633216	45.63	2021
2022	$/kWh	0.056916434	0.048943738	0.046748022	0.03582828	0.047109119	0.047109119	47.11	2022

2023	$/kWh	0.060706346	0.052195695	0.050601754	0.039739327	0.050810781	0.050810781	50.81	2023
2024	$/kWh	0.063356121	0.054474697	0.053075039	0.043059944	0.05349145	0.05349145	53.49	2024
2025	$/kWh	0.065459372	0.056791445	0.057419018	0.045059684	0.05618238	0.05618238	56.18	2025
2026	$/kWh	0.065377361	0.056618223	0.058916675	0.045774345	0.056671651	0.056671651	56.67	2026
2027	$/kWh	0.066370041	0.057470526	0.059460932	0.04649156	0.057448265	0.057448265	57.45	2027
2028	$/kWh	0.067678713	0.058651355	0.063320806	0.048644215	0.059573772	0.059573772	59.57	2028
2029	$/kWh	0.069197745	0.060328826	0.065926997	0.050250116	0.061425921	0.061425921	61.43	2029
2030	$/kWh	0.070740047	0.06252036	0.067778112	0.051705298	0.063185955	0.063185955	63.19	2030
2031	$/kWh	0.071133805	0.063467611	0.073302463	0.05315417	0.065264512	0.065264512	65.26	2031
2032	$/kWh	0.072344541	0.064933877	0.076576345	0.05476718	0.067155486	0.067155486	67.16	2032
2033	$/kWh	0.073575886	0.066434018	0.079996448	0.056429138	0.069108872	0.069108872	69.11	2033
2034	$/kWh	0.074828188	0.067968815	0.083569301	0.05814153	0.071126959	0.071126959	71.13	2034
2035	$/kWh	0.076101805	0.069539071	0.087301728	0.059905886	0.073212123	0.073212123	73.21	2035
2036	$/kWh	0.0773971	0.071145603	0.091200854	0.061723783	0.075366835	0.075366835	75.37	2036
2037	$/kWh	0.078714442	0.072789251	0.095274126	0.063596846	0.077593666	0.077593666	77.59	2037
2038	$/kWh	0.080054206	0.074470871	0.099529321	0.065526748	0.079895286	0.079895286	79.90	2038
2039	$/kWh	0.081416773	0.076191341	0.103974564	0.067515215	0.082274473	0.082274473	82.27	2039
2040	$/kWh	0.082802531	0.077951558	0.108618344	0.069564024	0.084734114	0.084734114	84.73	2040
2041	$/kWh	0.084211876	0.079752441	0.113469527	0.071675006	0.087277212	0.087277212	87.28	2041
2042	$/kWh	0.085645209	0.081594929	0.118537377	0.073850047	0.08990689	0.08990689	89.91	2042
2043	$/kWh	0.087102938	0.083479983	0.12383157	0.076091092	0.092626396	0.092626396	92.63	2043
2044	$/kWh	0.088585479	0.085408586	0.129362216	0.078400143	0.095439106	0.095439106	95.44	2044
2045	$/kWh	0.090093253	0.087381746	0.135139876	0.080779265	0.098348535	0.098348535	98.35	2045
2046	$/kWh	0.09162669	0.08940049	0.141175581	0.083230583	0.101358336	0.101358336	101.36	2046
2047	$/kWh	0.093186227	0.091465873	0.147480857	0.085756288	0.104472311	0.104472311	104.47	2047

Avoided Energy Costs Electric Heat and Electric Vehicles Weighted Average

Seasonal Avoided Energy Costs (pre-inflation)

Period	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Winter On-Peak	0.042948462	0.046553286	0.050901503	0.055575249	0.056916434	0.060706346	0.063356121	0.06545937	0.065377361	0.066370041	0.06767871	0.06919774	0.07074005	0.0711338	0.07234454	0.07357589	0.07482819	0.07610181	0.0773971	0.07871444	0.08005421	0.08141677	0.08280253	0.08421188	0.08564521	0.08710294	0.08858548	0.09009325	0.09162669	0.09318623
Winter Off-Peak	0.036876354	0.04066292	0.043353232	0.047862525	0.048943738	0.052195695	0.054474697	0.05679145	0.056618223	0.057470526	0.05865135	0.06032883	0.06252036	0.06346761	0.06493388	0.06643402	0.06796882	0.06953907	0.0711456	0.07278925	0.07447087	0.07619134	0.07795156	0.07975244	0.08159493	0.08347998	0.08540859	0.08738175	0.08940049	0.09146587
Summer On-Peak	0.028704835	0.033877957	0.042024216	0.044949693	0.046748022	0.050601754	0.053075039	0.05741902	0.058916675	0.059460932	0.06332081	0.065927	0.06777811	0.07330246	0.07657635	0.07999645	0.0835693	0.08730173	0.09120085	0.09527413	0.09952932	0.10397456	0.10861834	0.11346953	0.11853738	0.12383157	0.12936222	0.13513988	0.14117558	0.14748086
Summer Off-Peak	0.02178498	0.026867315	0.030786197	0.034145396	0.03582828	0.039739327	0.043059944	0.04505968	0.045774345	0.04649156	0.04864421	0.05025012	0.0517053	0.05315417	0.05476718	0.05642914	0.05814153	0.05990589	0.06172378	0.06359685	0.06552675	0.06751522	0.06956402	0.07167501	0.07385005	0.07609109	0.07840014	0.08077926	0.08323058	0.08575629

Seasonal and Peak Segmentation

Winter months / year	8
Summer months / year	4
Hours / year	8760
On-peak hours / day	16
Off-peak hours / day	8

Season	On-Peak	Off-Peak	Total
Winter	3,893.33	1,946.67	5,840.00
Summer	1,946.67	973.33	2,920.00

Electric Heat & EV Seasonal Load Segmentation

Season	Ratio
Summer Off-Peak	11.11%
Summer On-Peak	22.22%
Winter Off-Peak	22.22%
Winter On-Peak	44.44%
	100.00%

Weighted Average Annual Price (pre-inflation & WRP)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Hourly Wght. Avg. YOY	0.0361	0.0402	0.0450	0.0491	0.0505	0.0542	0.0568	0.0595	0.0598	0.0606	0.0626	0.0644	0.0661	0.0679	0.0697	0.0715	0.0734	0.0753	0.0773	0.0794	0.0815	0.0837	0.0860	0.0883	0.0907	0.0932	0.0958	0.0985	0.1012	0.1040

Add MRP & Inflation

MRP	1.09
Inflation	0.02

Weighted Average Annual Price (pre-inflation & WRP)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Hourly Wght. Avg. YOY	0.0401	0.0456	0.0521	0.0580	0.0608	0.0666	0.0712	0.0760	0.0779	0.0806	0.0848	0.0890	0.0933	0.0977	0.1022	0.1070	0.1120	0.1173	0.1228	0.1286	0.1347	0.1411	0.1478	0.1549	0.1623	0.1701	0.1783	0.1869	0.1959	0.2054

Avoided REC Cost

Source: AESC 2015 Update, Appendix B

Period	Units	Value
2018	$/kWh	0.005508139
2019	$/kWh	0.005958249
2020	$/kWh	0.005659665
2021	$/kWh	0.00680032
2022	$/kWh	0.006509963
2023	$/kWh	0.006051674
2024	$/kWh	0.005772086
2025	$/kWh	0.005405181
2026	$/kWh	0.004985127
2027	$/kWh	0.004586611
2028	$/kWh	0.004206788
2029	$/kWh	0.004558828
2030	$/kWh	0.004253013
2031	$/kWh	0.004253013
2032	$/kWh	0.004253013
2033	$/kWh	0.004253013
2034	$/kWh	0.004253013
2035	$/kWh	0.004253013
2036	$/kWh	0.004253013
2037	$/kWh	0.004253013
2038	$/kWh	0.004253013
2039	$/kWh	0.004253013
2040	$/kWh	0.004253013
2041	$/kWh	0.004253013
2042	$/kWh	0.004253013
2043	$/kWh	0.004253013
2044	$/kWh	0.004253013
2045	$/kWh	0.004253013
2046	$/kWh	0.004253013
2047	$/kWh	0.004253013

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Avoided Capacity Cost (pre	0.0055	0.0060	0.0057	0.0068	0.0065	0.0061	0.0058	0.0054	0.0050	0.0046	0.0042	0.0046	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043
Avoided Capacity Cost (pos	6.12	6.76	6.55	8.02	7.83	7.43	7.23	6.90	6.49	6.09	5.70	6.30	6.00	6.12	6.24	6.36	6.49	6.62	6.75	6.89	7.03	7.17	7.31	7.46	7.61	7.76	7.91	8.07	8.23	8.40

MRP	1.09
Inflation	2%
Convert to MW	1,000.00

DRIPE

Source: AESC 2015 Update, Appendix B

Energy

Period	Unit	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric Heat -Wgt. Avg.	Seasonal Weighted Average	Energy Storage - Wgt. Avg.
2018	$/kWh	1.25566E-06	5.06517E-07	0	0	4.40545E-07	7.3969E-07	8.12081E-07
2019	$/kWh	0	0	0	0	0	0	0
2020	$/kWh	0	0	0	0	0	0	0

Capacity

Period	Unit	Winter	Summer	ric Heat - Weighted Ave	Solar - Seasonal Weighted Average	Energy Storage - Wgt. Avg.
2018	$/kWh	0.001583956	0.00103838	0.001311168	0.00136285	0.001402097
2019	$/kWh	0.001012791	0.00068337	0.00084808	0.000879286	0.000902984
2020	$/kWh	0.000991781	0.000669757	0.000830769	0.000861274	0.00088444
2021	$/kWh	0.000179686	0.000165304	0.000172495	0.000173857	0.000174892
2022	$/kWh	0.000179201	0.000164577	0.000171889	0.000173274	0.000174326
2023	$/kWh	0.000178737	0.000163881	0.000171309	0.000172717	0.000173785
2024	$/kWh	0.000178182	0.000163048	0.000170615	0.000172049	0.000173137
2025	$/kWh	0.00017763	0.000162221	0.000169925	0.000171385	0.000172494
2026	$/kWh	0.000177082	0.000161399	0.000169241	0.000170726	0.000171855
2027	$/kWh	0.000176538	0.000160583	0.00016856	0.000170072	0.00017122
2028	$/kWh	0.000175998	0.000159772	0.000167885	0.000169422	0.000170589
2029	$/kWh	0.000175461	0.000158967	0.000167214	0.000168776	0.000169963
2030	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2031	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2032	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2033	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2034	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2035	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2036	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2037	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2038	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2039	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2040	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2041	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2042	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2043	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2044	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2045	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2046	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2047	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341

Electric Heat and Electric Vehicles - DRIPE (pre-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Energy	4.40545E-07	0	0																											
Capacity	0.001311168	0.00084808	0.000830769	0.000172495	0.000171889	0.000171309	0.000170615	0.00016993	0.000169241	0.00016856	0.00016788	0.00016721	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655
Total DRIPE	0.001311609	0.00084808	0.000830769	0.000172495	0.000171889	0.000171309	0.000170615	0.00016993	0.000169241	0.00016856	0.00016788	0.00016721	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655

Inflation	2%
Conversion to MW	1,000.00

Electric Heat DRIPE (post inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total DRIPE	1.337840737	0.882342644	0.881618693	0.186713876	0.189779136	0.19292199	0.195982934	0.19909469	0.202258148	0.205474195	0.20874375	0.21206773	0.2154471	0.21975604	0.22415116	0.22863418	0.23320687	0.237871	0.24262842	0.24748099	0.25243061	0.25747922	0.26262881	0.26788139	0.27323901	0.27870379	0.28427787	0.28996343	0.2957627	0.30167795

Solar DRIPE

Solar DRIPE (pre-inflation)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy	7.39688E-07	0	0												
Capacity	0.00136285	0.000879286	0.000861274	0.000173857	0.000173274	0.000172717	0.000172049	0.00017139	0.000170726	0.000170072	0.00016942	0.00016878	0.00016814	0.00016814	0.00016814
Total DRIPE	0.00136359	0.000879286	0.000861274	0.000173857	0.000173274	0.000172717	0.000172049	0.00017139	0.000170726	0.000170072	0.00016942	0.00016878	0.00016814	0.00016814	0.00016814

Solar DRIPE (pre-inflation)	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Energy															
Capacity	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814
Total DRIPE	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814

Inflation	2%
Conversion to MW	1,000.00

Solar DRIPE (post-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total DRIPE	1.39086186	0.914809363	0.913991069	0.188188586	0.19130869	0.194506868	0.197629728	0.20080504	0.20403371	0.207316685	0.21065491	0.21404936	0.21750102	0.22185104	0.22628807

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total DRIPE	0.23081383	0.2354301	0.24013871	0.24494148	0.24984031	0.25483712	0.25993386	0.26513254	0.27043519	0.27584389	0.28136077	0.28698798	0.29272774	0.2985823	0.30455394

Solar - Seasonal Demand by System Type

Season	Sum of 250 kW System - Annual Output (MW)	Sum of 500 kW System - Annual Output (MW)	Sum of 1,500 kW System - Annual Output (MW)
Summer Off-Peak	1%	1%	1%
Summer On-Peak	39%	39%	39%
Winter Off-Peak	1%	1%	1%
Winter On-Peak	59%	59%	59%
Total	1	1	1

Energy Storage DRIPE (pre-inflation)

Energy Storage DRIPE (pre-inflation)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy	8.12081E-07	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity	0.001402097	0.000902984	0.00088444	0.000174892	0.000174326	0.000173785	0.000173137	0.00017249	0.000171855	0.00017122	0.00017059	0.00016996	0.00016934	0.00016934	0.00016934
Total DRIPE	0.001402909	0.000902984	0.00088444	0.000174892	0.000174326	0.000173785	0.000173137	0.00017249	0.000171855	0.00017122	0.00017059	0.00016996	0.00016934	0.00016934	0.00016934

Energy Storage DRIPE (pre-inflation)	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934
Total DRIPE	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934

Inflation	2.00%
Convert to MWh	1,000.00

Energy Storage DRIPE (post-inflation)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total	1.430967683	0.939464253	0.938574317	0.189308465	0.192470217	0.195710408	0.198880287	0.20210385	0.205382054	0.208715853	0.21210623	0.2155542	0.21906076	0.22344197	0.22791081

Energy Storage DRIPE (post-inflation)	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total	0.23246903	0.23711841	0.24186077	0.24669799	0.25163195	0.25666459	0.26179788	0.26703384	0.27237452	0.27782201	0.28337845	0.28904601	0.29482693	0.30072347	0.30673794

New England Residential Energy Prices

Energy Prices Residential (Case Reference case Region New England)

https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2017&region=1-1&cases=ref2017~ref_no_cpp&start=2015&end=2050&f=A&linechart=~-

09:51:48 GMT-0400 (Eastern Daylight Time)

Source: U.S. Energy Information Administration

New England Residential Energy Prices

Year	Propane 2016 $/MMBtu	Distillate Fuel Oil 2016 $/MMBtu	Natural Gas 2016 $/MMBtu	Electricity 2016 $/MMBtu
2015	20.059196	19.634937	12.999855	57.913372
2016	18.986731	15.391558	12.499926	52.962849
2017	19.159531	18.481035	12.559583	53.759666
2018	20.3908	20.35202	12.730404	46.24337
2019	20.428343	21.432173	12.863449	47.102016
2020	20.36684	21.913502	13.038426	45.619492
2021	20.38199	22.292168	13.248834	45.495861
2022	20.818222	22.562029	13.447027	47.376621
2023	21.09973	22.895624	13.598397	49.17429
2024	21.193447	23.217937	13.719156	50.349106
2025	21.149662	23.695726	13.810126	51.765896
2026	21.188416	24.066542	13.868716	52.806141
2027	21.388361	24.263973	13.997381	53.399616
2028	21.446894	24.305296	14.186235	53.822887
2029	21.470636	24.524441	14.388145	54.817307
2030	21.637087	24.984591	14.524349	55.649223
2031	22.067629	25.394388	14.584588	55.851391
2032	22.390608	25.889307	14.683081	55.949352
2033	22.452869	25.806747	14.751159	56.23835
2034	22.691654	26.115984	14.936297	56.59457
2035	22.800667	26.332081	15.181598	57.886639
2036	23.140226	26.861704	15.332048	58.283558
2037	23.296213	26.936857	15.496017	58.576546
2038	23.60668	27.103247	15.618446	58.816032
2039	24.046312	27.475222	15.740956	57.837711
2040	24.210247	27.673616	15.790576	59.10891
2041	24.474936	27.717131	15.916462	59.452782
2042	24.614227	27.769522	16.047209	59.981743
2043	24.814363	27.830799	16.209641	60.750565
2044	24.986708	27.928757	16.403036	61.422989
2045	25.068331	28.020597	16.601873	61.820881
2046	25.256636	28.191952	16.78653	62.281025
2047	25.456972	28.537254	16.932384	63.031494
2048	25.692049	28.555511	17.094194	63.291729
2049	25.812935	28.743196	17.232834	63.588299
2050	26.039854	29.019983	17.207699	65.033279

Spot vs. Long-term Fuel Purchases

Category	Percent of Total	Discount from Base Residential
Long-term	10%	10%
Spot Purchase	90%	0%
Total	100%	N/A
Source	http://www.treesfullofmoney.com/2017-heating-oil-price-predictions/	
Assumptions	Based on EIA forecast, assume prices are increasing and customers experience historical 5 - 15% savings from pre-buy	

Spot vs. Long-term - Natural Gas

Category	Percent of Total	Discount from Base Residential
Long-term	5%	5%
Spot Purchase	95%	0%
Total	100%	N/A

Spot vs. Long-term - Natural Gas

Category	Percent of Total	Discount from Base Residential
Long-term	0%	5%
Spot Purchase	100%	0%
Total	100%	N/A

Adjusted Residential Fuel Oil Prices Based on Pre-Buy Forecast

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base Distillate Fuel Oil	19.63	15.39	18.48	20.35	21.43	21.91	22.29	22.56	22.90	23.22	23.70	24.07	24.26	24.31	24.52	24.98	25.39	25.89
Base Distillate Fuel Oil - Convert $ / MMBTU to $ / Gallon	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Distillate Fuel Oil - Apply Pre-buy Discount	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Pre-buy discount	10%																	
Distillate Fuel Oil - Convert $ / Gallon to $ / MMBTU	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Base Distillate Fuel Oil	25.81	26.12	26.33	26.86	26.94	27.10	27.48	27.67	27.72	27.77	27.83	27.93	28.02	28.19	28.54	28.56	28.74	29.02
Base Distillate Fuel Oil - Convert $ / MMBTU to $ / Gallon	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Distillate Fuel Oil - Apply Pre-buy Discount	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Distillate Fuel Oil - Convert $ / Gallon to $ / MMBTU	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

Adjusted Residential Natural Gas Prices Based on Pre-Buy Forecast

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base Natural Gas ($ / MMBTU)	13.00	12.50	12.56	12.73	12.86	13.04	13.25	13.45	13.60	13.72	13.81	13.87	14.00	14.19	14.39	14.52	14.58	14.68
Natural Gas - Apply Price Protection Discount	12.96735536	12.46867619	12.52818404	12.69857799	12.83129038	13.00582994	13.2157119	13.41340943	13.56440101	13.6848581	13.7756007	13.8340442	13.9623875	14.1507694	14.3521746	14.4880381	14.5481265	14.6463733

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Base Natural Gas ($ / MMBTU)	14.75	14.94	15.18	15.33	15.50	15.62	15.74	15.79	15.92	16.05	16.21	16.40	16.60	16.79	16.93	17.09	17.23	17.21
Natural Gas - Apply Price Protection Discount	14.7142811	14.8989563	15.143644	15.2937179	15.457277	15.5793999	15.7016036	15.7510996	15.8766708	16.007091	16.1691169	16.3620284	16.5603683	16.7445637	16.890053	17.0514585	17.18975	17.165

Assume pre-buy discount is 5%, with 5% of customers using

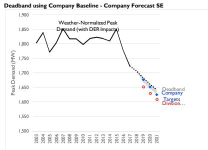
Propane 2016 $/MMBtu

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base Propane 2016 $/MMBtu	20.06	18.99	19.16	20.39	20.43	20.37	20.38	20.82	21.10	21.19	21.15	21.19	21.39	21.45	21.47	21.64	22.07	22.39
Propane - Apply Price Discount	20.06	18.99	19.16	20.39	20.43	20.37	20.38	20.82	21.10	21.19	21.15	21.19	21.39	21.45	21.47	21.64	22.07	22.39

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Base Propane 2016 $/MMBtu	22.45	22.69	22.80	23.14	23.30	23.61	24.05	24.21	24.47	24.61	24.81	24.99	25.07	25.26	25.46	25.69	25.81	26.04
Propane - Apply Price Discount	22.45	22.69	22.80	23.14	23.30	23.61	24.05	24.21	24.47	24.61	24.81	24.99	25.07	25.26	25.46	25.69	25.81	26.04

Assume pre-buy discount is zero

Deadband using Company Baseline - Company Forecast SE



% of standard error:	Synapse Min MW Reductions	Synapse Target MW Reductions	Synapse Max MW Reductions	Synapse Med Target	Synapse Max Target	Min - MW of Benefits
	50%	100%	150.0%	100%		50%

Weather-Normalized Peak Demand (with DER Impacts)

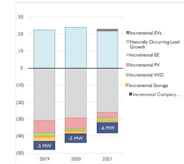
Year	Peak - Weather Norm Actual less impacts of EE and PV	Company Forecast	Company Targets (YoY Reduc)	Company Target Peak	Cumulative Reductions	Company Forecast SE	Forecast Less 0.5 SE	Synapse Min MW Reductions	Synapse Target MW Reductions	Synapse Max MW Reductions	Synapse Med Target	Synapse Max Target	Min - MW of Benefits	Med - MW of Benefits	Max - MW of Benefits
2003	1803														
2004	1839														
2005	1772														
2006	1803														
2007	1852														
2008	1817														
2009	1816														
2010	1798														
2011	1817														
2012	1822														
2013	1817														
2014	1811														
2015	1850														
2016	1778														
2017	1723	1723													
2018		1706		1706			1706								
2019		1682	-29	1677	-4.6	29.2	1667	14.6	29	44	1653	1638	0	15	29
2020		1661	-26	1651	-9.6	30.6	1646	15.3	31	46	1630	1615	0	15	31
2021		1642	-26	1625	-16.6	32.0	1626	16.0	32	48	1610	1594	0	16	32

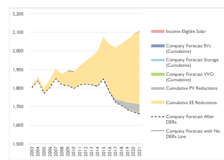
Year	Company Forecast with No DERs	Company Forecast with No DERs Line	Cumulative Load Growth	Cumulative EE Reductions	Cumulative PV Reductions	Company Forecast VVO (Cumulative)	Company Forecast Storage (Cumulative)	Company Forecast EVs (Cumulative)	Income Eligible Solar	Company Forecast After DERs	Cumulative EE Relative to 2018	Cumulative PV Relative to 2018	Cumulative Additional Company Effort	Company Target	Incremental Load Growth	Incremental EE	Incremental PV	Incremental VVO	Incremental Storage	Incremental EVs	Incremental Income Eligible Solar	Net	Incremental Company Effort
2003	1,813	1,813		(9)	0	0	0	0	0	1,803													
2004	1,860	1,860		(21)	0	0	0	0	0	1,839													
2005	1,802	1,802		(30)	0	0	0	0	0	1,772													
2006	1,844	1,844		(41)	0	0	0	0	0	1,803													
2007	1,902	1,902		(51)	0	0	0	0	0	1,852													
2008	1,878	1,878		(61)	0	0	0	0	0	1,817													
2009	1,893	1,893		(77)	0	0	0	0	0	1,816													
2010	1,887	1,887		(89)	0	0	0	0	0	1,798													
2011	1,919	1,919		(102)	(0)	0	0	0	0	1,817													
2012	1,944	1,944		(121)	(0)	0	0	0	0	1,822													
2013	1,968	1,968		(148)	(2)	0	0	0	0	1,817													
2014	2,001	2,001		(187)	(4)	0	0	0	0	1,811													
2015	2,075	2,075		(220)	(5)	0	0	0	0	1,850													
2016	2,036	2,036		(250)	(7)	0	0	0	0	1,778													
2017	2,018	2,018		(279)	(16)	0	0	0	0	1,723													
2018	2,041	2,041		(310)	(25)	0	0	0	0	1,706													
2019	2,063	2,063	22	(340)	(32)	-2	-1	0	-2	1,686	-35	-7	-5	1,681	22	(31)	(7)	(2)	(1)	0	(2)	(26)	-5
2020	2,087	2,087	46	(369)	(39)	-3	-2	0	-3	1,671	-70	-14	-10	1,661	24	(29)	(7)	(1)	(1)	0	(1)	(20)	-5
2021	2,109	2,109	68	(395)	(42)	-5	-3	1	-3	1,662	-104	-18	-16	1,646	22	(26)	(3)	(2)	(1)	1	0	(15)	-6

Notes:

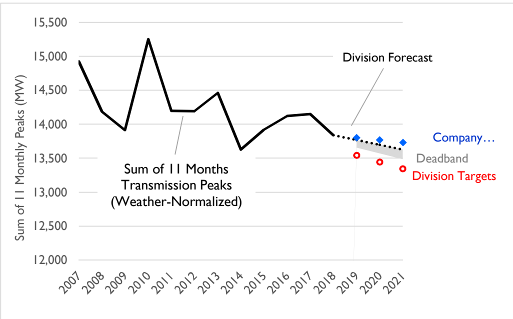
Company Forecast = "Reconstituted" less EE, PV, VVO, Storage, + EVs. See Attachment DIV 8-5.

Company Forecast Standard Error: Attachment DIV 8-7-2





Actuals and Predictions



	Sum of 11 Monthly Peaks	Sum of 11 Monthly				% of standard error:		50%	100%	150%			
Year	Monthly_Peak	Weather-Norm 11 Mo Baseline	Company's YoY Target Reductions	Company's Targets	Standard _Error	Bottom of Deadband	Synapse Target	Synapse Min MW Reductions	Synapse Medium MW Reductions	Synapse High MW Reductions	Min MW for Benefits Calc (excl Deadband)	Med MW for Benefits Calc (excl Deadband)	High MW for Benefits Calc (excl Deadband)
2007	15,038	14,924											
2008	14,290	14,192											
2009	13,420	13,919											
2010	15,098	15,253											
2011	14,177	14,198											
2012	14,380	14,194											
2013	14,826	14,462											
2014	13,909	13,628											
2015	13,990	13,921											
2016	13,928	14,121											
2017	13,906	14,151											
2018	NA	13,843											
2019	NA	13,772	36	13,807	228	13,658	13,544	114	228	342	0	114	228
2020	NA	13,701	34	13,773	255	13,573	13,445	128	255	383	0	128	255
2021	NA	13,630	36	13,737	284	13,488	13,346	142	284	425	0	142	284

	Year	Monthly_Peak	HDD	Tmp_max	Tmp_min	CDD	Weather_Normalize(	Standard_Error
1	2007	15,038	238	629	447	61	14,924	
2	2008	14,290	245	598	431	45	14,192	
3	2009	13,420	224	609	455	41	13,919	
4	2010	15,098	185	718	495	76	15,253	
5	2011	14,177	234	631	433	51	14,198	
6	2012	14,380	166	685	524	55	14,194	
7	2013	14,826	239	625	448	60	14,462	
8	2014	13,909	233	618	430	42	13,628	
9	2015	13,990	250	613	418	50	13,921	
10	2016	13,928	238	612	457	57	14,121	
11	2017	13,906	247	618	436	59	14,151	
12	2018	NA	227	632	452	54	13,843	201
13	2019	NA	227	632	452	54	13,772	228
14	2020	NA	227	632	452	54	13,701	255
15	2021	NA	227	632	452	54	13,630	284
16	2022	NA	227	632	452	54	13,559	312

Source: Attachment DIV 8-4

Polk Data - National Grid

RI - Cumulative									**Company Forecast**				Synapse Analysis	
													2013-201	**2017-2021**
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**CAGR**	**CAGR**
BEV(PEV)				32	41	117	193	313	483	725	1069	1557	77%	49%
HEV(PHEV)				178	182	413	538	772	1080	1486	2021	2726	44%	37%
				210	223	530	731	1085	1563	2211	3090	4283	51%	41%

RI - Incremental									**Company Forecast**					**2014-201'**	**2014-202**
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017 - Annualized**	**2018**	**2019**	**2020**	**2021**	**Std Dev**	131	359
BEV(PEV)				32	9	76	76	120	170	242	344	488			
HEV(PHEV)				178	4	231	125	234	308	406	535	705			
				210	13	307	201	354	478	648	879	1193			

Synapse Check	Forecast + .5 SD	0.5	827	1,058	1,372
	Forecast + 1 SD	1	1,007	1,238	1,552
	Forecast + 1.5 SD	1.5	1,186	1,417	1,731

Company Gross Targets	120%	778	1,055	1,432
	140%	907	1,231	1,670
	180%	1,166	1,582	2,147

Company Net Targets	Min	130	176	239
	Target	259	352	477
	Max	518	703	954

	2019		**2020**		**2021**	
	Medium	**High**	**Medium**	**High**	**Medium**	**High**
	259	518	352	703	477	954
Tons Avoided/Vehicl	2.15	2.15	2.15	2.15	2.15	2.15
Targets in Tons	556.85	1113.7	756.8	1511.45	1025.55	2051.1

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Source: Attachment DIV-1-1-3, Tab "9.EH - BCA Summary"

Rhode Island Power Sector Transformation | Benefit-Cost Analysis (BCA) Models | EH - BCA Summary

EH BCA ratios, comprehensive benefits and costs, and sensitivity analyses

EH - BCA Summary

Societal Cost Test

RI Electric Heat BCA

	Electric Heat - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	832,005
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	$	(3,591,188)
	Avoided Renewable Energy Credit (REC) Cost	$	(324,190)
	Greenhouse Gas (GHG) Externality Costs	$	1,479,569
	Criteria Air Pollutant and Other Environmental Costs	$	672
	Non-Electric Avoided Fuel Cost	$	12,737,349
	Economic Development	$	-
		$	**11,134,218**
Costs	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	$	1,126,843
	Program Participant / Prosumer Benefits / Costs	$	6,756,766
		$	**7,883,608**

BCA Ratio		**1.41**
Net Benefits	$	3,250,610
First-Year Tonnes CO2 Avoided	$	1,638
Net Benefit/Incremental Tonne CO2	$	1,984

Comprehensive Benefits & Costs

	Applicable Cost Test			Electric Heat - BCA Ratio		
	SCT	UCT	RIM			
Benefits	x	x	x	Forward Commitment: Capacity Value	$	832,005
	x	x	x	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	$	(3,591,188)
	x	x	x	Avoided Renewable Energy Credit (REC) Cost	$	(324,190)
		x	x	Wholesale Market Price Impacts	$	(16,575)
	x			Greenhouse Gas (GHG) Externality Costs	$	1,479,569
	x			Criteria Air Pollutant and Other Environmental Costs	$	672
	x			Non-Electric Avoided Fuel Cost	$	12,737,349
	x			Economic Development	$	-
		x	x	Change in Utility Revenue	$	11,484,377
					$	**22,602,020**
Costs	x	x	x	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	$	1,126,843
	x			Program Participant / Prosumer Benefits / Costs	$	6,756,766
					$	**7,883,608**

Source: Attachment DIV 1-1-3, Tab "11.EH - Benefits"

	Forward Commitment: Capacity Value			Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
	Reduction in Peak Load (4-yr delay)	kW	Calculated. Based on RI draft testimony.	139.21	298.16	476.84	476.84	476.84	476.84	476.84	476.84	476.84	476.84
/	1 - Losses	%	AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Change in Electric Load at System	kW		151.32	324.09	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31
x	System Coincidence Factor	%	Based on NY BCA model	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
x	Derating Factor	%	Based on NY BCA model	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
=	Avoided Generation Capacity	kW		151.32	324.09	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31
	Increased Energy Use	MWh		(1,473)	(3,214)	(5,103)	(5,103)	(5,103)	(5,103)	(5,103)	(5,103)	(5,103)	(5,103)
	1-Losses	%		92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
	Change in Energy Use at System	MWh		-1601	-3493	-5547	-5547	-5547	-5547	-5547	-5547	-5547	-5547
	Non-Embedded CO2 Cost per MWh	$/MWh		48.03	48.54	49.05	48.71	48.33	47.92	47.47	46.99	46.47	45.91
	Electricity Added Carbon Costs			-76908	-169566	-272075	-270165	-268069	-265782	-263328	-260637	-257733	-254643
	Non-Embedded CO2 Cost per Metric Ton	$/Metric Ton		93.36	94.34	95.34	94.67	93.94	93.13	92.27	91.33	90.31	89.23
	Increase in Metric Tons of CO2	Metric Tons		(824)	(1,797)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)
	Fuel Oil CO2 Reduction												
	Fuel Oil CO2 Emissions Reduction	metric tons		1,287	2,841	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492
	Net Reduction in CO2	metric tons		464	1,043	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638
Synapse Targets:	**Incremental Reduction in CO2**	**metric tons**	**(medium target)**	**464**	**580**	**595**							
			(High Target)	**556**	**696**	**714**							

Forward Commitment: Capacity Value	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25	Yr 26	Yr 27	Yr 28	Yr 29	Yr 30	
Reduction in Peak Load (4-yr delay)	476.84	476.84	476.84	476.84	476.84	402.59	317.87	222.69	222.69	222.69	222.69	222.69	222.69	222.69	222.69	157.74	83.51	-	-	-	
1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	
Change in Electric Load at System	518.31	518.31	518.31	518.31	518.31	437.59	345.51	242.06	242.06	242.06	242.06	242.06	242.06	242.06	242.06	171.46	90.77	-	-	-	
System Coincidence Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
Derating Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
Avoided Generation Capacity	518.31	518.31	518.31	518.31	518.31	437.59	345.51	242.06	242.06	242.06	242.06	242.06	242.06	242.06	242.06	171.46	90.77	-	-	-	
Increased Energy Use	(5,103)	(5,103)	(5,103)	(5,103)	(5,103)	(3,906)	(2,541)	(1,008)	(1,008)	(1,008)	(1,008)	(1,008)	(1,008)	(1,008)	(1,008)	(731)	(355)	-	-	-	
1-Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	
Change in Energy Use at System	-5547	-5547	-5547	-5547	-5547	-4246	-2762	-1095	-1095	-1095	-1095	-1095	-1095	-1095	-1095	-795	-386	0	0	0	
Non-Embedded CO2 Cost per MWh	45.30	44.66	43.97	54.23	55.31	56.41	57.53	58.68	59.84	61.03	62.24	63.48	64.74	66.03	67.34	68.68	70.05	71.44	72.86	74.30	
Electricity Added Carbon Costs	-251291	-247703	-243871	-300822	-306800	-239527	-158919	-64264	-65541	-66844	-68172	-69527	-70908	-72318	-73755	-54583	-27061	0	0	0	
Non-Embedded CO2 Cost per Metric Ton	88.06	86.80	85.46	105.41	107.51	109.64	111.82	114.04	116.31	118.62	120.98	123.38	125.84	128.34	130.89	133.49	136.14	138.85	141.61	144.42	
Increase in Metric Tons of CO2	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,185)	(1,421)	(563)	(563)	(563)	(563)	(563)	(563)	(563)	(563)	(409)	(199)	-	-	-	
Fuel Oil CO2 Reduction																					
Fuel Oil CO2 Emissions Reduction	4,492	4,492	4,492	4,492	4,492	3,593	2,567	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,026	499	-	-	-	-
Net Reduction in CO2	1,638	1,638	1,638	1,638	1,638	1,408	1,146	851	851	851	851	851	851	851	851	617	300	-	-	-	-
Incremental Reduction in CO2																					

Compare to Company Calculations

Source: Attachment DIV 1-1-3, Tab "10.EH - Inputs"			
Number of Conversions - ASHP 3 ton	39	45	50
Number of Conversions - GSHP 4 ton	18	20	24
Number of Conversions - GSHP 82 ton		1	
Source: Attachment DIV 25-18, Assumptions			
Avoided CO2 per Year/unit - ASHP 3 ton	3	3	3
Avoided CO2 per Year/unit - GSHP 4 ton	8	8	8
Avoided CO2 per Year/unit - GSHP 82 ton		59	
Source: Attachment DIV 25-18, Targets			
Incremental Avoided CO2 per Year - Equipment Incentives	171	194	224
Incremental Avoided CO2 per Year - GSHP 82 ton	-	59	-

EH - Benefits

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	RI Benefit Description / Calculations	Unit	SCT	UTC	RIM	Source	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
	Forward Commitment: Capacity Value															
	Reduction in Peak Load (4-yr delay)	kW				Calculated. Based on RI draft testimony.	139.21	298.16	476.84	476.84	476.84	476.84	476.84	476.84	476.84	476.84
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Change in Electric Load at System	kW					151.32	324.09	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31
x	System Coincidence Factor	%				Based on NY BCA model	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
x	Derating Factor	%				Based on NY BCA model	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
=	Avoided Generation Capacity	kW					151.32	324.09	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31
x	Avoided Unit Cost of Electric Capacity	$ / MW				AESC 2015 Update, Appendix B	-	-	-	-	151,748.25	145,443.49	154,497.40	173,684.98	193,938.75	214,296.15
=	**Benefit from Forward Commitment: Capacity Value**	$	x	x	x		**$ -**	**$ -**	**$ -**	**$ -**	**$ 78,653**	**$ 75,385**	**$ 80,077**	**$ 90,023**	**$ 100,520**	**$ 111,072**
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)															
	Change in Energy Usage at Meter	MWh				Calculated. Based on RI draft testimony.	(1,473.03)	(3,213.87)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Change in Energy Usage at System	MWh				Calculated	(1,601.12)	(3,493.34)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)
x	Avoided Energy Cost	$ / MWh				AESC 2015 Update, Appendix B	40.12	45.63	52.07	57.95	60.82	66.58	71.17	75.96	77.92	80.58
=	**Benefit from Energy Supply & Transmission Operating**	$	x	x	x	Calculated	**$ (64,231)**	**$ (159,415)**	**$ (288,822)**	**$ (321,447)**	**$ (337,375)**	**$ (369,301)**	**$ (394,762)**	**$ (421,338)**	**$ (432,202)**	**$ (446,972)**
	Avoided Renewable Energy Credit (REC) Cost															
	Change in Energy Usage at Meter	MWh				Calculated. Based on RI draft testimony.	(1,473.03)	(3,213.87)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Change in Energy Usage at System	MWh				Calculated	(1,601.12)	(3,493.34)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)
x	Avoided REC Cost	$ / MWh				AESC 2015 Update, Appendix B	6.12	6.76	6.55	8.02	7.83	7.43	7.23	6.90	6.49	6.09
	Benefit from Avoided REC Cost	$	x	x	x	Calculated	**$ (9,805)**	**$ (23,604)**	**$ (36,312)**	**$ (44,503)**	**$ (43,455)**	**$ (41,204)**	**$ (40,086)**	**$ (38,289)**	**$ (36,019)**	**$ (33,803)**
	Wholesale Market Price Impacts															
	Change in Energy Usage at Meter	MWh				Calculated. Based on RI draft testimony.	(1,473.03)	(3,213.87)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Change in Energy Usage at System	MWh				Calculated	(1,601.12)	(3,493.34)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)
x	DRIPE (Energy + Cross-fuel Capacity)	$ / MWh				AESC 2015 Update, Appendix B	1.34	0.88	0.88	0.19	0.19	0.19	0.20	0.20	0.20	0.21
=	**Benefit from Wholesale Market Price Impacts**	$		x	x	Calculated	**$ (2,142)**	**$ (3,082)**	**$ (4,890)**	**$ (1,036)**	**$ (1,053)**	**$ (1,070)**	**$ (1,087)**	**$ (1,104)**	**$ (1,122)**	**$ (1,140)**

	RI Benefit Description / Calculations	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20
	Forward Commitment: Capacity Value										
	Reduction in Peak Load (4-yr delay)	476.84	476.84	476.84	476.84	476.84	402.59	317.87	222.69	222.69	222.69
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Change in Electric Load at System	518.31	518.31	518.31	518.31	518.31	437.59	345.51	242.06	242.06	242.06
x	System Coincidence Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
x	Derating Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
=	Avoided Generation Capacity	518.31	518.31	518.31	518.31	518.31	437.59	345.51	242.06	242.06	242.06
x	Avoided Unit Cost of Electric Capacity	235,794.87	259,373.47	290,550.94	308,169.87	314,333.27	320,619.93	327,032.33	333,572.98	340,244.44	347,049.33
=	**Benefit from Forward Commitment: Capacity Value**	**$ 122,215**	**$ 134,436**	**$ 150,595**	**$ 159,727**	**$ 162,922**	**$ 140,301**	**$ 112,993**	**$ 80,744**	**$ 82,359**	**$ 84,006**
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)										
	Change in Energy Usage at Meter	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(3,906.37)	(2,541.26)	(1,007.61)	(1,007.61)	(1,007.61)
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Change in Energy Usage at System	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(4,246.05)	(2,762.24)	(1,095.23)	(1,095.23)	(1,095.23)
x	Avoided Energy Cost	84.83	89.02	93.26	97.68	102.23	107.00	112.02	117.28	122.80	128.60
=	**Benefit from Energy Supply & Transmission Operating**	**$ (470,502)**	**$ (493,756)**	**$ (517,283)**	**$ (541,781)**	**$ (567,025)**	**$ (454,343)**	**$ (309,414)**	**$ (128,446)**	**$ (134,495)**	**$ (140,846)**
	Avoided Renewable Energy Credit (REC) Cost										
	Change in Energy Usage at Meter	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(3,906.37)	(2,541.26)	(1,007.61)	(1,007.61)	(1,007.61)
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Change in Energy Usage at System	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(4,246.05)	(2,762.24)	(1,095.23)	(1,095.23)	(1,095.23)
x	Avoided REC Cost	5.70	6.30	6.00	6.12	6.24	6.36	6.49	6.62	6.75	6.89
	Benefit from Avoided REC Cost	**$ (31,624)**	**$ (34,955)**	**$ (33,263)**	**$ (33,928)**	**$ (34,607)**	**$ (27,022)**	**$ (17,930)**	**$ (7,252)**	**$ (7,397)**	**$ (7,545)**
	Wholesale Market Price Impacts										
	Change in Energy Usage at Meter	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(3,906.37)	(2,541.26)	(1,007.61)	(1,007.61)	(1,007.61)
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Change in Energy Usage at System	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(4,246.05)	(2,762.24)	(1,095.23)	(1,095.23)	(1,095.23)
x	DRIPE (Energy + Cross-fuel Capacity)	0.21	0.21	0.22	0.22	0.22	0.23	0.23	0.24	0.24	0.25
=	**Benefit from Wholesale Market Price Impacts**	**$ (1,158)**	**$ (1,176)**	**$ (1,195)**	**$ (1,219)**	**$ (1,243)**	**$ (971)**	**$ (644)**	**$ (261)**	**$ (266)**	**$ (271)**

	RI Benefit Description / Calculations	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25	Yr 26	Yr 27	Yr 28	Yr 29	Yr 30	Nominal Value	NPV
	Forward Commitment: Capacity Value												
	Reduction in Peak Load (4-yr delay)	222.69	222.69	222.69	222.69	222.69	157.74	83.51	-	-	-		
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%		
=	Change in Electric Load at System	242.06	242.06	242.06	242.06	242.06	171.46	90.77	-	-	-	10,195.21	$4,758.02
x	System Coincidence Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		
x	Derating Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		
=	Avoided Generation Capacity	242.06	242.06	242.06	242.06	242.06	171.46	90.77	-	-	-	10,195.21	4,758.02
x	Avoided Unit Cost of Electric Capacity	353,990.31	361,070.12	368,291.52	375,657.35	383,170.50	390,833.91	398,650.59	406,623.60	414,756.07	423,051.19		
=	**Benefit from Forward Commitment: Capacity Value**	**$ 85,686**	**$ 87,400**	**$ 89,148**	**$ 90,930**	**$ 92,749**	**$ 67,011**	**$ 36,186**	**$ -**	**$ -**	**$ -**	**$ 2,315,136**	**$ 832,005**
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)												
	Change in Energy Usage at Meter	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(731.16)	(355.43)	-	-	-		
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%		
=	Change in Energy Usage at System	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(794.74)	(386.34)	-	-	-	(94,152.56)	(47,709.01)
x	Avoided Energy Cost	134.69	141.08	147.80	154.86	162.27	170.07	178.25	186.86	195.91	205.42		
=	**Benefit from Energy Supply & Transmission Operating**	**$ (147,516)**	**$ (154,520)**	**$ (161,877)**	**$ (169,607)**	**$ (177,727)**	**$ (135,158)**	**$ (68,867)**	**$ -**	**$ -**	**$ -**	**$ (8,009,028)**	**$ (3,591,188)**
	Avoided Renewable Energy Credit (REC) Cost												
	Change in Energy Usage at Meter	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(731.16)	(355.43)	-	-	-		
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%		
=	Change in Energy Usage at System	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(794.74)	(386.34)	-	-	-	(94,152.56)	(47,709.01)
x	Avoided REC Cost	7.03	7.17	7.31	7.46	7.61	7.76	7.91	8.07	8.23	8.40		
	Benefit from Avoided REC Cost	**$ (7,695)**	**$ (7,849)**	**$ (8,006)**	**$ (8,166)**	**$ (8,330)**	**$ (6,165)**	**$ (3,057)**	**$ -**	**$ -**	**$ -**	**$ (631,871)**	**$ (324,190)**
	Wholesale Market Price Impacts												
	Change in Energy Usage at Meter	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(731.16)	(355.43)	-	-	-		
/	1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%		
=	Change in Energy Usage at System	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(794.74)	(386.34)	-	-	-	(94,152.56)	(47,709.01)
x	DRIPE (Energy + Cross-fuel Capacity)	0.25	0.26	0.26	0.27	0.27	0.28	0.28	0.29	0.30	0.30		
=	**Benefit from Wholesale Market Price Impacts**	**$ (276)**	**$ (282)**	**$ (288)**	**$ (293)**	**$ (299)**	**$ (221)**	**$ (110)**	**$ -**	**$ -**	**$ -**	**$ (27,899)**	**$ (16,575)**

	Greenhouse Gas (GHG) Externality Costs																																			
	Change in Energy Usage at Meter	MWh		Calculated. Based on RI draft testimony.	(1,473.03)	(3,213.87)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(3,906.37)	(2,541.26)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(731.16)	(355.43)	-	-	-		
/	1 - Losses	%		AESC 2015, p. 286. ISO Distribution Losses.	92%	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92		
=	Change in Energy Usage at System	MWh		Calculated	(1,601.12)	(3,493.34)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(4,246.05)	(2,762.24)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(794.74)	(386.34)	-	-	-	(94,152.56)	(47,709.01)
x	Non-Embedded CO2 Cost	$ / MWh		2015 AESC. Exhibit 4-7	48.03	48.54	49.05	48.71	48.33	47.92	47.47	46.99	46.47	45.91	45.30	44.66	43.97	54.23	55.31	56.41	57.53	58.68	59.84	61.03	62.24	63.48	64.74	66.03	67.34	68.68	70.05	71.44	72.86	74.30		
=	**Electricity Added Carbon Benefits**	$		**Calculated**	**$ (76,908)**	**$ (169,566)**	**$ (272,075)**	**$ (270,165)**	**$ (268,069)**	**$ (265,782)**	**$ (263,328)**	**$ (260,637)**	**$ (257,733)**	**$ (254,643)**	**$ (251,291)**	**$ (247,703)**	**$ (243,871)**	**$ (300,822)**	**$ (306,800)**	**$ (239,527)**	**$ (158,919)**	**$ (64,264)**	**$ (65,541)**	**$ (66,844)**	**$ (68,172)**	**$ (69,527)**	**$ (70,908)**	**$ (72,318)**	**$ (73,755)**	**$ (54,583)**	**$ (27,061)**	**$ -**	**$ -**	**$ -**	**$ (4,740,810)**	**$ (2,338,135)**
		Increase in tons CO2		implied tons CO2 from addl electricity	(824)	(1,797)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,185)	(1,421)	(563)	(563)	(563)	(563)	(563)	(563)	(563)	(563)	(409)	(199)	-	-	-		
	Non-Embedded CO2 Cost	$ / metric ton		2015 AESC. Exhibit 4-7	93.36	94.34	95.34	94.67	93.94	93.13	92.27	91.33	90.31	89.23	88.06	86.80	85.46	105.41	107.51	109.64	111.82	114.04	116.31	118.62	120.98	123.38	125.84	128.34	130.89	133.49	136.14	138.85	141.61	144.42		
	Natural Gas CO2 Emissions per Unit	metric ton / MMBTU		source: EIA	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05		
	Natural Gas Usage Reduction	MMBTU		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
x	Natural Gas CO2 Emissions Reduction	metric tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	**Natural Gas Carbon Benefits**	$		**Portion of data needed is not available**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Fuel Oil CO2 Emissions per Unit	metric ton / MMBTU		https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07		
	Fuel Oil Usage Reduction	MMBTU		Calculated	17,595.13	38,825.92	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	49,105.98	35,081.82	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	14,023.93	6,817.30	-	-	-		
x	Fuel Oil CO2 Emissions Reduction	metric tons		Calculated	1,287	2,841	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	3,593	2,567	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,026	499	-	-	-		
=	**Fuel Oil Carbon Benefits**	$		**Portion of data needed is not available**	**$ 120,187**	**$ 268,000**	**$ 428,283**	**$ 425,276**	**$ 421,977**	**$ 418,376**	**$ 414,514**	**$ 410,278**	**$ 405,706**	**$ 400,842**	**$ 395,565**	**$ 389,917**	**$ 383,885**	**$ 473,533**	**$ 482,944**	**$ 393,929**	**$ 287,020**	**$ 161,259**	**$ 164,464**	**$ 167,732**	**$ 171,066**	**$ 174,465**	**$ 177,933**	**$ 181,469**	**$ 185,075**	**$ 136,967**	**$ 67,906**	**$ -**	**$ -**	**$ -**	**$ 8,108,566**	**$ 3,817,704**
	Propane CO2 Emissions per Unit	metric ton / MMBTU		NY BCA model	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06		
	Propane Usage Reduction	MMBTU		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
x	Propane CO2 Emissions Reduction	metric tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	**Propane Carbon Benefits**	$		**Portion of data needed is not available**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
=	**Benefit from Reduced Greenhouse Gas Externality Cost**	$	x	Portion of data needed is not available	**$ 43,279**	**$ 98,434**	**$ 156,207**	**$ 155,111**	**$ 153,908**	**$ 152,594**	**$ 151,186**	**$ 149,640**	**$ 147,973**	**$ 146,199**	**$ 144,274**	**$ 142,214**	**$ 140,014**	**$ 172,712**	**$ 176,144**	**$ 154,402**	**$ 128,101**	**$ 96,995**	**$ 98,923**	**$ 100,889**	**$ 102,894**	**$ 104,939**	**$ 107,024**	**$ 109,151**	**$ 111,320**	**$ 82,384**	**$ 40,844**	**$ -**	**$ -**	**$ -**	**$ 3,367,756**	**$ 1,479,569**
	net reduction in co2 (metric tons)				**464**	**1,043**	**1,638**	**1,638**	**1,638**	**1,638**	**1,638**	**1,638**	**1,638**	**1,638**	**1,638**	**1,638**	**1,638**	**1,638**	**1,638**	**1,408**	**1,146**	**851**	**851**	**851**	**851**	**851**	**851**	**851**	**851**	**617**	**300**	**-**	**-**	**-**		
	Criteria Air Pollutant and Other Environmental Costs																																			
	Natural Gas SO2 Emissions per Unit	short ton / MMBTU		EPA	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07		
	Natural Gas NOX Emissions per Unit	short ton / MMBTU		EPA	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.5543E-05	-4.5543E-05	-4.5543E-05		
x	Natural Gas Usage Reduction	MMBTU		Natural gas is not used in base case and thus not replaced	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	Natural Gas SO2 Emissions Reduction	short tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
=	Natural Gas NOX Emissions Reduction	short tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-														
	Fuel Oil SO2 Emissions per Unit	short ton / MMBTU		https://www3.epa.gov/ttnchie1/conference/ei12/area/hane	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791		
	Fuel Oil NOX Emissions per Unit	short ton / MMBTU		https://www3.epa.gov/ttnchie1/conference/ei12/area/hane	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05		
x	Fuel Oil Usage Reduction	MMBTU		Calculated.	17,595.13	38,825.92	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	49,105.98	35,081.82	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	14,023.93	6,817.30	-	-	-		
=	Fuel Oil SO2 Emissions Reduction	short tons		Calculated	2.71	5.97	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	7.55	5.40	2.97	2.97	2.97	2.97	2.97	2.97	2.97	2.97	2.16	1.05	-	-	-	171.36	83.60
=	Fuel Oil NOX Emissions Reduction	short tons		Calculated	1.14	2.52	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.19	2.28	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	0.91	0.44	-	-	-		
	Propane SO2 Emissions per Unit	short ton / MMBTU		https://www3.epa.gov/ttn/chief/ap42/ch01/index.html	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07		
	Propane NOX Emissions per Unit	short ton / MMBTU		https://www3.epa.gov/ttn/chief/ap42/ch01/index.html	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05		
x	Propane Usage Reduction	MMBTU		Propane is not used in base case and thus not replaced	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	Propane SO2 Emissions Reduction	short tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
=	Propane NOX Emissions Reduction	short tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
	Total SO2 Emissions Reduction	short tons		Calculated	2.71	5.97	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	7.55	5.40	2.97	2.97	2.97	2.97	2.97	2.97	2.97	2.97	2.16	1.05	-	-	-		
x	SO2 Pollutant Cost	$ / short ton		AESC 2015 Exhibit 4.1. Emission Allowance Prices per Sh	1.20	1.25	1.30	1.35	1.41	1.46	1.52	1.59	1.65	1.72	1.79	1.86	1.93	2.01	2.09	2.18	2.26	2.36	2.45	2.55	2.65	2.76	2.87	2.99	3.11	3.23	3.36	3.50	3.64	3.79		
=	**Net Avoided SO2 Cost**	$		**Calculated**	**$ 3**	**$ 7**	**$ 12**	**$ 13**	**$ 13**	**$ 14**	**$ 14**	**$ 15**	**$ 16**	**$ 16**	**$ 17**	**$ 18**	**$ 18**	**$ 19**	**$ 20**	**$ 16**	**$ 12**	**$ 7**	**$ 7**	**$ 8**	**$ 8**	**$ 8**	**$ 9**	**$ 9**	**$ 9**	**$ 7**	**$ 4**	**$ -**	**$ -**	**$ -**	**$ 319**	**$ 140**
	Total NOX Emissions Reduction	short tons		Calculated	1.14	2.52	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.19	2.28	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	0.91	0.44	-	-	-		
x	NOX Pollutant Cost	$ / short		AESC 2015 Exhibit 4.1. Emission Allowance Prices per Sh	10.82	11.26	11.72	12.19	12.68	13.19	13.73	14.28	14.86	15.46	16.08	16.73	17.41	18.11	18.85	19.61	20.40	21.22	22.08	22.97	23.90	24.87	25.87	26.92	28.00	29.13	30.31	31.54	32.81	34.14		
=	**Net Avoided NOX Cost**	$		**Calculated**	**$ 12**	**$ 28**	**$ 47**	**$ 49**	**$ 51**	**$ 53**	**$ 55**	**$ 57**	**$ 59**	**$ 62**	**$ 64**	**$ 67**	**$ 69**	**$ 72**	**$ 75**	**$ 63**	**$ 47**	**$ 27**	**$ 28**	**$ 29**	**$ 30**	**$ 31**	**$ 32**	**$ 34**	**$ 35**	**$ 27**	**$ 13**	**$ -**	**$ -**	**$ -**	**$ 1,215**	**$ 532**
=	**Total Avoided Cost from SO2 and NOX Reduction**	$	x	**Calculated**	**$ 16**	**$ 36**	**$ 59**	**$ 61**	**$ 64**	**$ 66**	**$ 69**	**$ 72**	**$ 75**	**$ 78**	**$ 81**	**$ 84**	**$ 88**	**$ 91**	**$ 95**	**$ 79**	**$ 59**	**$ 34**	**$ 35**	**$ 36**	**$ 38**	**$ 39**	**$ 41**	**$ 43**	**$ 44**	**$ 34**	**$ 17**	**$ -**	**$ -**	**$ -**	$ 1,534	$ 672
	Non-Electric Avoided Fuel Cost																																			
	Natural Gas Consumption Cost	$ / MMBTU		https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-A	12.73	12.86	13.04	13.25	13.45	13.60	13.72	13.81	13.87	14.00	14.19	14.39	14.52	14.58	14.68	14.75	14.94	15.18	15.33	15.50	15.62	15.74	15.79	15.92	16.05	16.21	16.40	16.60	16.79	16.93		
x	Natural Gas Reduced Consumption	MMBTU		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	**Natural Gas Avoided Cost**	$		**Calculated**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Fuel Oil Consumption Cost	$ / MMBTU		https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-A	20.15	21.22	21.69	22.07	22.34	22.67	22.99	23.46	23.83	24.02	24.06	24.28	24.73	25.14	25.63	25.55	25.85	26.07	26.59	26.67	26.83	27.20	27.40	27.44	27.49	27.55	27.65	27.74	27.91	28.25		
x	Fuel Oil Reduced Consumption	MMBTU		Calculated	17,595.13	38,825.92	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	49,105.98	35,081.82	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	14,023.93	6,817.30	-	-	-		
=	**Fuel Oil Avoided Cost**	$		**Calculated**	**$ 354,515**	**$ 823,803**	**$ 1,332,007**	**$ 1,355,024**	**$ 1,371,428**	**$ 1,391,705**	**$ 1,411,297**	**$ 1,440,339**	**$ 1,462,879**	**$ 1,474,880**	**$ 1,477,392**	**$ 1,490,713**	**$ 1,518,683**	**$ 1,543,592**	**$ 1,573,676**	**$ 1,254,593**	**$ 907,034**	**$ 503,812**	**$ 513,945**	**$ 515,383**	**$ 518,567**	**$ 525,684**	**$ 529,480**	**$ 530,312**	**$ 531,315**	**$ 386,394**	**$ 188,495**	**$ -**	**$ -**	**$ -**	**$ 26,926,948**	**$ 12,737,349**
	Propane Consumption Cost	$ / MMBTU		https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-A	20.39	20.43	20.37	20.38	20.82	21.10	21.19	21.15	21.19	21.39	21.45	21.47	21.64	22.07	22.39	22.45	22.69	22.80	23.14	23.30	23.61	24.05	24.21	24.47	24.61	24.81	24.99	25.07	25.26	25.46		
x	Propane Reduced Consumption	MMBTU		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	**Propane Avoided Cost**	$		**Calculated**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
=	**Non-Electric Avoided Fuel Costs**	$	x	**Calculated**	**$ 354,515**	**$ 823,803**	**$ 1,332,007**	**$ 1,355,024**	**$ 1,371,428**	**$ 1,391,705**	**$ 1,411,297**	**$ 1,440,339**	**$ 1,462,879**	**$ 1,474,880**	**$ 1,477,392**	**$ 1,490,713**	**$ 1,518,683**	**$ 1,543,592**	**$ 1,573,676**	**$ 1,254,593**	**$ 907,034**	**$ 503,812**	**$ 513,945**	**$ 515,383**	**$ 518,567**	**$ 525,684**	**$ 529,480**	**$ 530,312**	**$ 531,315**	**$ 386,394**	**$ 188,495**	**$ -**	**$ -**	**$ -**	**$ 26,926,948**	**$ 12,737,349**
	Economic Development																																			
	Economic development (residential)																																			
	Economic development factor	$ / Total Resource Cost		RI Collaborative, RI EERMC. Email C. Lane, dated 10/24/1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
x	Total resource cost	$		Calculated	$ 2,782,449	$ 2,989,632	$ 3,223,932	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
=	**Total residential economic benefit**	$			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Economic development (commercial)																																			
	Economic development factor	$ / Total Resource Cost		RI Collaborative, RI EERMC. Email C. Lane, dated 10/24/1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
x	Total resource cost	$		Calculated	$ -	$ 965,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
=	**Total commercial economic benefit**	$			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
=	**Total economic benefit (residential + commercial)**	$	x		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Increased Utility Revenue																																			
	Electricity Increase at Revenue	MWh		Need specific systems and specifications from NG	1,473.03	3,213.87	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	3,906.37	2,541.26	1,007.61	1,007.61	1,007.61	1,007.61	1,007.61	1,007.61	1,007.61	1,007.61	731.16	355.43	-	-	-		
x	Non-Bypassable Charges	$ / MWh		Confirm approach. Used Appendix B, wholesale + risk pr	$ 171	$ 181	$ 192	$ 204	$ 237	$ 245	$ 254	$ 265	$ 272	$ 279	$ 290	$ 302	$ 315	$ 326	$ 335	$ 344	$ 353	$ 362	$ 372	$ 383	$ 395	$ 407	$ 420	$ 433	$ 447	$ 460	$ 482	$ -	$ -	$ -		
=	**Increased Utility Revenue**	$	x	**Calculated Value**	**$ 252,143**	**$ 581,787**	**$ 977,675**	**$ 1,040,401**	**$ 1,210,928**	**$ 1,250,397**	**$ 1,296,618**	**$ 1,353,368**	**$ 1,386,284**	**$ 1,425,385**	**$ 1,479,117**	**$ 1,542,917**	**$ 1,606,809**	**$ 1,662,625**	**$ 1,708,459**	**$ 1,343,760**	**$ 897,932**	**$ 364,288**	**$ 374,997**	**$ 386,196**	**$ 397,910**	**$ 410,165**	**$ 422,990**	**$ 436,413**	**$ 450,466**	**$ 336,324**	**$ 171,169**	**$ -**	**$ -**	**$ -**	**$ 24,767,521**	**$ 11,484,377**

PREVIOUS TARGETS (INCORRECT)

ANNUALIZED CO2 Reductions

Program Design Element	Program Metrics	Target Levels	Targets (annual metric tons CO2)		
			2018	2019	2020
1. GSHP Program	Carbon reduction (metric tons CO2 avoided per year)	Min	0	44	0
		Mid	**0**	**55**	**0**
		Max	0	66	0
2. Equipment Incentives	Carbon reduction (metric tons CO2 avoided per year)	Min	119	134	156
		Mid	**149**	**168**	**195**
		Max	179	202	234

Final Targets (combined metric tons CO2 avoided per yer)

	2018	2019	2020
Min	119	178	156
Mid	**149**	**223**	**195**
Max	179	268	234

GSHP: 55.23 tons avoided CO2 expected per year of the system
Equipment Incentives: 149, 168, and 195 incremental tons annually for years 1, 2, 3

REVISED TARGETS (CORRECTED)

Program Design Element	Program Metrics	Target Levels	Targets (annual		
			2018	2019	2020
1. GSHP Program	Carbon reduction (metric tons CO2 avoided per year)	Min	0	47	0
		Mid	**0**	**59**	**0**
		Max	0	71	0
2. Equipment Incentives	Carbon reduction (metric tons CO2 avoided per year)	Min	137	155	179
		Mid	**171**	**194**	**224**
		Max	206	232	269

Final Targets (combined metric tons CO2 avoided per yer)

	2018	2019	2020
Min	137	202	179
Mid	**171**	**253**	**224**
Max	206	303	269

GSHP: 59 tons avoided CO2 expected per year of the system
Equipment Incentives: 171, 194, and 224 incremental tons annually for years 1, 2, 3

Change in Targets (absolute)	2018	2019	2020
Min	18	24	23
Mid	**22**	**30**	**29**
Max	27	36	35

Change in Targets (percentage)	2018	2019	2020
Min	15%	13%	15%
Mid	**15%**	**13%**	**15%**
Max	15%	13%	15%

Attachment DIV 25-18

Electric Heat Workpaper 9.2 Assumptions

Assumptions				
Carbon Emissions Factors - non-electric fuels				
Fuel	**Lbs / MMBTU**	**Short Ton / MMBTU**	**Metric Ton / MMBTU**	**Source**
Natural Gas	117	0.0585	0.0530704	https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11
Fuel Oil	161.3	0.08065	0.0731645	https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11
Propane	139	0.0695	0.0630494	https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11

	Metric tons C	**% reduction**	
Average annual emissions of an oil-heated home	~8	n/a	3855
Average annual avoided CO2 from oil-to-ccASHP conversion	~3	38%	282.0493
Average annual avoided CO2 from oil-to-GSHP conversion	~5	63%	

	2017	2018	2019	2020	2021
Medium Target:					
EE Measure Lifetime (years)		9.5	9.8	11.4	11.4
EE Energy Savings (lftm MWh)		1,712,064	1,904,592	2,160,318	2,160,318
EE Energy Savings (MWh)	201,347	179,968	194,677	189,509	189,509
EE Capacity Savings (MW)	29	30	35	34	34
EE Benefits ($1000)		$373,005	$438,942	$451,783	$451,783
EE Funding ($1000)		$115,547	$124,932	$109,090	$109,090
EE Net Benefits (before incentive)		$257,458	$314,010	$342,693	$342,693
Costs as % of Benefits		31%	28%	24%	24%
EE COSE ($/MWh)		7.1	7.7	6.2	6.2
EE Incentive ($1000)		5,777	6,247	5,455	5,455
Maximum Target:					
Scale-up factor			1.06	1.12	1.12
EE Energy Savings (MWh)			205,801	211,804	211,804
EE Capacity Savings (MW)			37	38	38
EE Funding ($1000)			132,071	121,924	121,924
EE Incentive ($1000)			6,604	6,096	6,096

Notes:

Nat Grid Workpaper 9-1, page 3 has EE MW targets that are the same as the Three-Year Plan

It also has EE MW Max targets. They are presented above.

The rest of the max target information is just scaled up by the same ratio as MW.

Table From National Grid 2018-2020 Three-Year EE Plan

Electric Programs	2018	2019*	2020
Savings and Benefits			
Annual MWh Savings	179,968	194,677	189,509
Lifetime MWh Savings	1,712,064	1,904,592	2,160,318
Savings as a Percent of 2015 Sales	2.40%	2.60%	2.53%
Annual Peak kW Savings	29,639	35,188	34,224
Winter Peak kW Savings	29,092	26,517	28,466
Total Benefits (RI Test)	$ 373,004,694	$ 438,942,301	$ 451,782,884
Costs			
Total Funding Required	$ 115,547,860	$ 124,932,991	$ 109,090,025
Cents per lifetime kWh	$ 0.071	$ 0.077	$ 0.062
EE Program Charge per kWh	$ 0.01090	$ 0.01390	$ 0.01193
Benefit Cost Ratio (RI Test)	2.93	2.88	3.23
Participation	TBD	TBD	TBD
*2019 includes 25,539 Annual MWh and correlated costs and benefits, as an adder for future innovation.			