

**Before the
Rhode Island Public Utilities Commission**

Proceeding on the Narragansett Electric)
Company d/b/a National Grid Proposed)
Tariff Changes)

Docket No. 4780

**Direct Testimony of
Tim Woolf and Melissa Whited**

On Behalf of
The Division of Public Utilities and Carriers

April 25, 2018

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS	1
2. REGULATORY REVIEW AND COST RECOVERY	4
3. MULTI-YEAR RATE PLANS.....	15
4. RATEMAKING RECOMMENDATION FOR THIS DOCKET IF THERE IS NO MULTI-YEAR RATE PLAN.....	26
5. NATIONAL GRID’S PERFORMANCE INCENTIVE MECHANISM PROPOSAL.....	29
a. National Grid’s Proposal	29
b. Critique of National Grid’s Proposal.....	37
6. ELECTRIC TRANSPORTATION INITIATIVE	44
a. Off-Peak Charging Rebate Pilot	47
b. Charging Station Demonstration Program	51
c. Discount Pilot for DC Fast Charging Accounts	54
d. Company Fleet Expansion	55
e. Education and Outreach	57
7. ELECTRIC HEAT INITIATIVE	61
8. ELECTRIC STORAGE INITIATIVE.....	63
9. INCOME ELIGIBLE SOLAR INITIATIVE	64
10. ADVANCED METERING FUNCTIONALITY	64
a. National Grid’s Proposal	64
b. Recommendations	71
11. BENEFIT-COST ANALYSES.....	71
a. The Role of Benefit-Cost Analyses	71
b. National Grid’s Benefit-Cost Analyses	74

c. Critique of National Grid's Benefit-Cost Analysis	78
d. Recommendations	83

1 **1. INTRODUCTION AND QUALIFICATIONS**

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

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

5 **Q. Please describe Synapse Energy Economics.**

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

18 **Q. Please summarize your professional and educational experience.**

19 A. **Mr. Woolf:** Before joining Synapse Energy Economics, I was a commissioner at the
20 Massachusetts Department of Public Utilities (DPU) from 2007 through 2011. In that
21 capacity, I was responsible for overseeing a substantial expansion of clean energy
22 policies, including significantly increased ratepayer-funded energy efficiency programs;

1 an update of the DPU energy efficiency guidelines; the implementation of decoupled
2 rates for electric and gas companies; the promulgation of net metering regulations; review
3 and approval of smart grid pilot programs; and review and approval of long-term
4 contracts for renewable power. I was also responsible for overseeing a variety of other
5 dockets before the Commission, including several electric and gas utility rate cases.

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

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

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

21 I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science
22 in Environment and Resources, both from the University of Wisconsin-Madison. Prior to
23 rejoining Synapse, I published an article in the Journal of Regional Analysis and Policy

1 regarding the economic impacts of water transfers, analyzed state water efficiency
2 policies while at the Wisconsin Public Service Commission, and conducted econometric
3 analyses of energy efficiency cost-effectiveness. My resume is attached as Exhibit
4 TW/MW-2.

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

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

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

8 A. **Mr. Woolf:** Yes. I have testified before the Rhode Island Public Utilities Commission
9 (the Commission) on behalf of the Division in National Grid's (the Company's) Energy
10 Efficiency and System Reliability Plans. I was an active member of the Docket 4600
11 Working Group, and I assisted the Division with the Rhode Island Power Sector
12 Transformation report recently submitted to Governor Raimondo. I also recently testified
13 before the Commission on behalf of the Division in Docket 4783 on National Grid's
14 proposed advanced metering (AMF) pilot and in Docket 4770 on National Grid's rate
15 case.

16 **Ms. Whited:** Yes. I recently testified before the Commission on behalf of the Division in
17 Docket 4783 on National Grid's proposed AMF pilot and in Docket 4770 on National
18 Grid's rate case.

19 **Q. What is the purpose of your testimony?**

20 A. The purpose of our testimony is to respond to certain aspects of the Company's Power
21 Sector Transformation proposals.

1 **2. REGULATORY REVIEW AND COST RECOVERY**

2 **Q. Please describe the changes that National Grid is recommending to the regulatory**
3 **framework as it relates to the power sector transformation proposals.**

4 A. National Grid is proposing that the Commission treat new PST-related investments
5 differently from traditional, i.e., conventional, distribution system investments. The
6 Company originally proposed the PST program in Docket 4770. The Commission then
7 asked the Company to refile in a separate docket 4780. But regardless of the procedural
8 technicalities, the Company's proposal separates important distribution business activities
9 from the rest of its integrated utility operations, moving away from an integrated long-
10 term approach to running the distribution business to a stream of separate and siloed
11 activities, the costs of which are recovered through a largely riskless rate recovery
12 mechanism.

13 **Q. How would cost recovery be altered by the Company's PST proposal?**

14 Each rate case would set base distribution rates using a future, one-year test year, and
15 those base rates would remain in place until the Company decides to file a new rate case.
16 In addition, the Infrastructure, Safety, and Reliability (ISR) process would continue to be
17 used to recover the costs of relevant, conventional capital investments. The Company
18 would file an ISR Plan each year for review and approval by the Commission for the next
19 year's investments.

20 PST investments, which may or may not be eligible for review under the ISR,
21 would be addressed on a multi-year basis with annual cost recovery filings.¹ The

¹ Direct testimony of the PST Panel, p. 11, line 29.

1 Company would file with the Commission an annual PST Plan that includes several
2 years' worth of investments to reflect longer-term PST planning priorities, separately
3 from the rest of its distribution business. The Commission would approve (a) the overall
4 category of PST investments; (b) the proposed multi-year PST initiatives within each
5 category; and (c) the actual PST investments for the forthcoming year for each of those
6 initiatives.

7 PST investments would also be subject to a different cost recovery mechanism
8 than applies to the base distribution business. National Grid proposes to establish a set of
9 PST Factors to recover the forecasted capital costs and operations and maintenance
10 (O&M) expenses for the forthcoming PST Plan Year. The Company would also establish
11 a set of PST Reconciliation Factors to recover or credit any under- or over-recovery of
12 the actual PST investments relative to the planned PST investments.² For purposes of the
13 testimony, we refer to this mechanism as the proposed "PST Tracker."

14 During the annual review under the PST Tracker, the Commission would review
15 historical PST investments to make sure the costs actually incurred were reasonable and
16 prudent for cost recovery. The Commission would also review the forecasted PST
17 investments for the forthcoming year. In that manner, the annual review under the PST
18 Tracker would be very similar to the ISR process.

² Schedule PST-1, Chapter 10, p. 186.

1 **Q. Is the Company asking the Commission to pre-approve PST investments?**

2 A. Yes. National Grid states that the PST Tracker would be the mechanism through which
3 the Company seeks and obtains approval to make a particular investment.³ Again, this
4 essentially mirrors what is taking place under the ISR.

5 **Q. What reasons does the Company provide for treating PST investments differently**
6 **from conventional distribution system investments?**

7 A. There are several reasons that the Company provides for its proposed regulatory
8 framework. First, the Company asks for a fair opportunity to recover prudently-incurred
9 cost, as well as revenue stability. The Company claims that without timely cost recovery
10 it would not be able to meet the Commission's PST objectives.⁴

11 Second, the Company notes that there are statutory and other limitations regarding
12 other potential funding mechanisms, such as the ISR, the energy efficiency (EE), and the
13 system reliability planning (SRP) mechanisms.⁵

14 Third, the Company claims that stakeholder input regarding PST investments is
15 critical, and that a general rate case does not allow for this type of input. National Grid
16 claims that if it were to "move forward with these investments without critical feedback
17 and input of all interested participants, it would not be certain that its investments were
18 appropriately meeting the needs of the state and its customers."⁶

³ Direct testimony of PST Panel, p.5, lines 10-11.

⁴ Direct Testimony of PST Panel, p.11, lines 29-32.

⁵ Direct Testimony of PST Panel, p. 17, lines 3-18.

⁶ PST Panel Direct Testimony, p. 18, lines 8-11.

1 Fourth, National Grid claims that, relative to recovery of costs through rate cases, its
2 annual stakeholder process for reviewing PST investments “will provide concurrence and
3 certainty about Power Sector Transformation investments before-hand, as opposed to
4 after-the-fact, and result in more efficient and quicker progress to the next generation
5 electric grid.”⁷

6 **Q. Do you have any concerns about the Company’s proposed regulatory framework
7 for PST investments?**

8 A. Yes. There are very significant problems with the Company’s approach that would have
9 detrimental effects on the ability of the Division and the Commission to evaluate the
10 distribution business activities of the Company on a logical, integrated basis. The cost
11 recovery proposal shifts cost risks to ratepayers with little or no risk to the Company. It
12 also would result in a spending/cost recovery cycle that would be difficult for the
13 Division and the Commission to evaluate and control. Spending would lack needed
14 discipline, with a very ineffective process to assure prudence.

15 **Q. Please elaborate further on your concerns.**

16 First, the Company’s approach exacerbates the already fractured process for planning,
17 reviewing, and approving utility investments.

18 Second, the PST Tracker allows full reconciliation of the Company’s PST
19 initiative costs. This provides little incentive for the Company to contain those costs. In
20 fact, what the Company is essentially proposing is the near equivalent to a new
21 Commission-approved ISR process that pertains to the PST initiatives. While it is

⁷ PST Panel Direct Testimony, p. 18, lines 11-14.

1 understandable from a utility shareholder point of view why the Company would want
2 ISR-like tracker that provides recovery of all expenditures, this mechanism is not in the
3 interest of ratepayers in the context of Power Sector Transformation.

4 **Q. Are you implicitly suggesting that there also is a problem with the ISR mechanism?**

5 A. No. Up to this point in the history of the ISR, the mechanism has worked effectively.
6 With a few exceptions that the Division accepted and supported for unique reasons, the
7 ISR process has typically been narrowly tailored to address the need for the utility to
8 invest in the core utility system to assure the reliability and safety of the system. Because
9 the ISR removes all regulatory lag between the time of investing and the time the costs
10 are recovered for those investments, the mechanism encourages investment in an aging
11 system and removes the tendency of the utility to defer needed investments in between
12 rate cases because of short-term profit objectives.

13 The safeguard for ratepayers in the case of the ISR is that the Division plays a
14 significant role in reviewing and agreeing to the capital spending plan up front. It is a
15 very time-consuming process, but it has yielded benefits to ratepayers through the
16 targeted investments. The Division has been comfortable with the process to date
17 because the Division is an active participant in the capital planning approval process
18 before the investment plan is filed. Because the ISR investments have tended to revolve
19 around asset management of the traditional components of the distribution system, the
20 program has been manageable and workable.

1 **Q. Given recent success with the ISR, what is the problem with creating a similar**
2 **mechanism through the PST Tracker?**

3 Having acknowledged recent success of the ISR, however, it is still very important to
4 point out that there are limits. To the extent the scope of a fully reconciling cost recovery
5 mechanism expands to more and more business activities, the benefits begin to be
6 outweighed by the detriments. First and foremost, a process that allows recovery of
7 controllable costs through a tracker causes a shift of thinking in the utility. We believe it
8 can cause the utility to pay much less attention to cost control, to the detriment of
9 ratepayers who are ultimately paying for the whole program. The risks to the utility's
10 shareholders are substantially reduced. As a consequence, the utility may develop the
11 tendency to make investments even when there may be other alternatives because the risk
12 of cost recovery being denied are minimal and the process allows a smooth path to
13 growth in the rate base, an outcome which is not always in the ratepayers' best interest.

14 **Q. Isn't there a safeguard built into the process that allows after-the-fact review of the**
15 **project expenditures?**

16 A. Theoretically, yes. But the reality is that the utility is in the driver's seat. In Rhode
17 Island, the Division is simply not staffed or funded to do a deep dive review of every
18 project to assure that all the ratepayer dollars were prudently spent. For that reason, only
19 in cases where the negligent management of a project is readily apparent does the after-
20 the-fact review provide a practical means of recourse. When the scope of the projects is
21 narrow and straightforward, like the typical projects that are reviewed in the ISR, the
22 process is manageable. But once the scope expands to projects that are highly complex,
23 with very sophisticated IT and other systems involved, the protections to ratepayers

1 become more theoretical than real. Trying to perform a *post hoc* review of project
2 management and expenditure planning on complex systems projects is extremely
3 challenging, especially for a jurisdiction like Rhode Island where personnel resources are
4 constrained.

5 **Q. Are you suggesting the Commission try to alter the ISR?**

6 A. No. The ISR is a statutory mechanism. Because it is statutory, it limits the
7 Commission's authority to alter it. The Division still believes that the ISR continues to
8 provide benefits in a process that has worked effectively. We are only using the ISR as
9 an example to illustrate the risks to ratepayers if a similar mechanism is adopted for parts
10 of the distribution business that do not fall neatly into the eligibility categories for the
11 ISR. That is one of the core problems with the Company's PST Tracker proposal.

12 **Q. In light of the problems you have identified with the PST planning and PST
13 Tracker, what is the Division proposing in its place?**

14 A. The Division believes it is inappropriate and detrimental to ratepayers for most of the
15 initiatives set forth in the Company's PST proposal to be reviewed and addressed outside
16 of a rate case. We will elaborate further in the testimony on this point when we discuss
17 the need for multi-year rate plans, through which a comprehensive, integrated multi-year
18 business plan can be fully evaluated. Further, as explained in the testimony of Division
19 witness Greg Booth, the Company has chosen how to define activities that are grid
20 modernization for inclusion in its proposed PST cost tracker. In that context, the
21 Company has defined it too broadly. Specifically, there are at least two significant
22 initiatives that are not Grid Modernization at all. They are initiatives that the Company
23 should be undertaking as a regular part of its distribution business.

1 **Q. Is there other information that supports the premise that cost recovery for**
2 **initiatives that modernize the grid should occur through base rates?**

3 A. Yes. The practices of National Grid across jurisdictions is a good example. In Docket
4 4770 Division Data Request 24-12, the Division asked the Company the following data
5 request:

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

11 In response, the Company identified numerous projects. After seeing the list, the
12 Division asked a follow-up data request as follows in Docket 4770 Division 32-53:

13 “Referring to the response to DIV 24-12, for each of the initiatives identified in
14 the response, please indicate whether there were any special rate recovery
15 mechanisms (outside of base distribution rates) used to recover the costs of the
16 initiative, describe how the special rate recovery mechanism operates, and
17 indicate whether it is a fully reconciling tracker similar to the one proposed in
18 Docket 4780 that allows recovery of O&M and capital costs whether they
19 exceed original estimates or not.”

20 **Q. Did the Company’s answer reveal anything important?**

21 A. Yes. Of the 20 initiatives identified, only 2 projects actually had costs recovered from a
22 two-way tracker. One was a demand response initiative, the costs of which apparently
23 flow through an applicable energy efficiency program tracker. The only other related to
24 utility-owned solar projects in Massachusetts. No other projects operated like the PST
25 Tracker proposed in Rhode Island. The response identifies only 4 other projects where

1 costs are tracked. But these projects arose in the context of the New York REV
2 proceeding, which deferred cost recovery and capped total expenditures at \$44 million
3 for a selection of REV activities. It appears that the Company's affiliate has the right to
4 file a petition to request higher recovery if the utility exceeds the budget, but it is not
5 guaranteed. All of the 14 remaining projects on the list were not recovered through a
6 tracker at all, with 11 of those projects specifically recovered through base distribution
7 rates.

8 **Q. Do any of the projects being recovered through base distribution rates address**
9 **activities similar to what the Company has proposed in this docket?**

10 A. Yes. The System Data Portal project, an Advanced Data Analytics project, a Hosting
11 Capacity Analysis relating to distributed generation interconnections, a Remote Terminal
12 Unit (RTU) project, a Data Management System (DMS) pilot project, an energy storage
13 demonstration project, automating field devices, installing feeder monitoring sensors, and
14 implementing some telecommunications upgrades relating to reclosers on the distribution
15 system.

16 **Q. Does the Company explain why inclusion of these projects in base distribution rates**
17 **was possible?**

18 A. Yes. The Company points out that there was a three-year multi-year rate plan, stating:
19 "Note that base distribution rates for Niagara Mohawk Power Corporation (NMPC), the
20 Company's affiliate in upstate New York, are based on a three-year forward looking rate
21 case, so proposed revenue requirements are approved in addition to historic additions to
22 rate base, O&M costs are adjusted to include known and measurable impacts to the test
23 year O&M." Ironically, this is the type of ratemaking the Division is advocating in this

1 rate case for addressing the recovery of costs in the future over several years, rather than
2 setting rates for one year at a time or adopting the fully reconciling PST Tracker
3 proposed by the Company in Docket 4780.

4 **Q. Which initiatives has Mr. Booth identified as ones that should be undertaken by the**
5 **Company as a part of its traditional distribution business?**

6 A. As Mr. Booth explains, the GIS Enhancements and the DSCADA program, each of
7 which is discussed in Chapter 3 of PST-1, are initiatives that the Company should be
8 implementing as a part of its prudent operation of the distribution business. For that
9 reason, the Division proposes the Company move forward immediately with the GIS
10 Enhancements and begin to take steps for DSCADA implementation. Division witness
11 Michael Ballaban addressed the Division's proposal on how the costs of the GIS
12 Enhancements should be reflected in the revenue requirement for the rate year in his
13 testimony in Docket 4770. It is not clear whether the DSCADA program is ready for
14 advancement in the rate year, but the Division believes the Company should be
15 undertaking the project without delay by no later than calendar year 2020. The Company
16 should then seek recovery of the costs of the DSCADA by filing for rate relief through
17 the rate case process, but the Division does not believe it is appropriate to establish a
18 special cost tracker for the cost recovery outside of a rate case.

19 **Q. What about the Company's proposal for the System Data Portal?**

20 A. The Division supports the implementation of the System Data Portal project. The project
21 has already been partially funded through the SRP. But the Company has not proposed to
22 move forward more completely yet. Like its other PST projects, the Company proposes
23 the additional costs of the System Data Portal project be recovered through its proposed

1 PST Tracker. The Division, of course, opposes that means of recovery. Instead, the
2 Division recommends that the annual costs associated with moving forward with the
3 System Data Portal project be included in the rate year revenue requirement. There are
4 no incremental capital costs and even the Company has conceded that there is no
5 practical impediment to recovery of the costs through base rates in this rate case. (See the
6 response to Division 27-11.) According to the Company, the going forward costs are only
7 operation and maintenance costs associated with time spent by engineers on the portal.

8 **Q. Does the Division agree with the Company's annual cost estimate for the System**
9 **Data Portal?**

10 A. No. As Division witness Greg Booth testifies in Docket 4770, the proposal to fund three
11 engineers appears excessive. For that reason, the Division proposes to reduce the request
12 by one third. The Division's revenue requirement witness in Docket 4770, Michael
13 Ballaban, has reduced the annual cost by 30 percent in the rate year revenue requirement.

14 **Q. What about the Company's proposal to perform an AMI study?**

15 A. The Division believes the Company should perform the study. However, the Division
16 disagrees with the Company's estimate and allocation of the cost of the AMI study
17 chargeable to Rhode Island, as described in the testimony of Division witness Michael
18 Ballaban in Docket 4770. The Division proposes that the study go forward, subject to the
19 cost recovery adjustments recommended by Mr. Ballaban for the rate year. As Mr.
20 Ballaban explains in that Docket, the Company estimated a cost to Rhode Island for a
21 combined study with New York at \$2 million. However, for the reasons explained by
22 Mr. Ballaban, the Division believes the Company's estimate is not reasonable and lacks a

1 defensible foundation. Mr. Ballaban explains why the rate allowance funded by Rhode
2 Island should be \$1 million, which should be amortized over three years.

3 **Q. Are there any other actions the Company should be taking in connection with grid**
4 **modernization?**

5 A. Yes. Consistent with the testimony of Division witness Greg Booth, the Division
6 recommends that the Company be directed to complete a comprehensive grid
7 modernization plan (GMP) that is developed in sync with the AMI Study. The plan
8 should be developed with stakeholder input and could take place under the umbrella of
9 this docket or separately. But the GMP should be filed with the Commission around the
10 same time as the AMI Study, to allow AMI deployment and the GMP to be considered
11 together.

12 **3. MULTI-YEAR RATE PLANS**

13 **Q. Why does the Division support the concept of multi-year rate plans?**

14 A. One of the most important reasons is that a multi-year plan requires and facilitates
15 planning over a multi-year horizon on a fully integrated basis. In the context of Power
16 Sector Transformation, planning needs to take place with multiple years in view, relating
17 the activities to the core distribution business. For that reason alone, implementing a
18 multi-year plan is highly preferable. But there also is another important benefit. The
19 multi-year rate plan not only provides the most effective way to advance the very
20 important multi-year transformative initiatives, it also addresses in a balanced manner the
21 tension relating to cost recovery that often exists between the competing interests of
22 ratepayers and shareholders.

1 **Q. What are the ratepayer interests in this context?**

2 A. The most important is the obvious interest in protecting ratepayers from unreasonable
3 rates, including rate stability. In addition, there is the interest of advancing important
4 public policies that need the utility to make significant investments with cost discipline.
5 This interest is now becoming more important than ever as policymakers look to advance
6 important transformational initiatives relating to climate change, an evolving distribution
7 system, and accommodation of a distribution system with distributed resources.

8 **Q. What is the interest of the utility in this context?**

9 A. The interest of the utility is straightforward and not surprising. In providing service to
10 consumers, utilities incur costs. In past decades, costs could be more easily recovered by
11 sales growth and other factors that increased usage which, in turn, increased revenues to
12 cover on-going costs and investments. In recent years usage on the electric side of the
13 business is either flat or declining. Revenue decoupling helps stabilize the revenue
14 stream for the distribution utility, but it does not provide additional revenue in between
15 rate cases to provide the necessary financial signals for the utility to invest. In fact, we
16 believe this is the primary reason for the passage of the statute establishing the ISR. It
17 also is self-evident from the fact that it is embedded in the revenue decoupling section of
18 the law. The electric system was aging, yet the Company did not have the revenue stream
19 to invest without depleting its earnings in between rate cases. By creating the ISR at the
20 same time as implementing decoupling, conventional investments were facilitated and
21 service quality vastly improved while energy efficiency goals were being achieved.
22 There may have been other ways to address this issue, but Rhode Island policymakers
23 chose the ISR mechanism.

1 If we were on a path of business as usual, there might not be a need for a change.
2 But that is not the state of the industry. As mentioned earlier, policymakers acting on
3 behalf of customers desire transformational changes in the utility business to advance
4 important goals. But these initiatives require a longer-term investment vision that utilizes
5 multi-year investment plans. Phasing-in of significant projects is likely to become more
6 important over the next decade. The “one-year-at-a-time” ISR is not adequate, even if
7 the investments are eligible under the statute. The Company in this case acknowledges
8 that a large infusion of investments is needed to transform the power industry. But it is
9 reluctant to advance the programs unless it has assurance of cost recovery without any
10 regulatory lag or significant risk.

11 **Q. Couldn’t the Commission simply order the Company to implement the initiatives**
12 **and address cost recovery in their next rate case?**

13 A. Yes. The Commission, like other state commissions across the country, always has the
14 option to issue mandates for utilities to take certain actions or implement initiatives,
15 while addressing cost recovery in subsequent rate cases. It may be that the Commission
16 would need to resort to such action in Rhode Island. However, while the Commission
17 could assert its authority aggressively to simply order the Company to implement
18 programs without addressing how the costs will be recovered until the next rate case,
19 taking such action means the utility implements under regulatory duress. On the surface
20 it may appear effective, but too often risk averse, financially-influenced inertia can slow
21 or halt real progress behind the scenes. Many regulatory mandates can be effective and
22 are necessary. But the types of initiatives being contemplated here are intended to be

1 transformational. In order for the transformation to be effectively accomplished, it is
2 preferable to address it in a manner that works for all parties concerned.

3 **Q. How has the Company proposed to address its interest to recover the costs in a**
4 **timely manner?**

5 A. The Company has proposed a fully reconciling PST Tracker. The tracker would
6 undoubtedly address the Company's interest in the most ideal manner from the
7 Company's perspective. In such case, the Company would obtain up-front approval. The
8 approval would allow it to spend money on the initiative with no concerns about earnings
9 impacts because the Company would be virtually guaranteed to get all its money back
10 from the spending, with a formulaic return on its investment.

11 **Q. But would that be a balanced approach that is fair to ratepayers?**

12 A. No. The Company's proposal does not address the interests of ratepayers who should be
13 assured that the utility is operating efficiently at reasonable cost. From the ratepayers'
14 perspective, there needs to be some financial pressure created to assure the utility
15 experiences real consequences for any lack of discipline in spending.

16 **Q. What about the Company's claim that without timely cost recovery it would not be**
17 **able to meet the Commission's PST objectives?**

18 A. This claim assumes that the Company's capability to implement an initiative is obstructed
19 unless the Company gets its money first or at least a guarantee for later. In the history of
20 ratemaking, this has never been the general rule. In fact, it has typically been the
21 opposite. Rates have been set for one year and the Company exercises its duty to
22 maintain safe and reliable service with the revenue obtained by the rates in effect. The

1 reconciliation of some of the ordinary business expenses and cost of capital is the
2 exception. Currently, only 15% of annual electric distribution-related revenue is
3 recovered through reconciling mechanisms. (See the response to Docket 4770 PUC 3-9,
4 Attachment 3-9, page 1 of 2, line 3) The idea that absent a fully reconciling cost recovery
5 mechanism the Company cannot do its job or run the business not only lacks credibility,
6 but flies in the face of ordinary principles of ratemaking. Timely recovery undoubtedly
7 makes it much easier for the Company to maintain higher earnings while carrying out its
8 responsibilities. However, while factors such as regulatory lag or lack of dollar-for-dollar
9 precision between revenues and costs may cause some earnings instability, they would
10 not, as a practical matter, prevent the Company from meeting the PST objectives.

11 **Q. What is the Division’s proposal for a balanced and effective solution?**

12 A. The balanced and most effective solution that is consistent with the Division’s vision for
13 advancing the “utility of the future” is the concept of multi-year rate plans. There is
14 nothing new in the industry about such plans. They have been implemented in many
15 places. But in recent years, they have not been utilized in Rhode Island. Given the needs
16 and interests already identified, it is the most balanced answer that is fair to all
17 participants.

18 **Q. What are the key features of a multi-year rate plan?**

19 A. First, the Company should be required to file a multi-year business plan with granular
20 and reliable forecasts of costs for each year of the plan, including any forecasted costs
21 relating to grid modernization and AMI. This would allow all parties to examine the
22 direction in which the utility is planning to move. It also would allow for significant
23 stakeholders and regulatory input in a comprehensive and integrated way. Most of the

1 utility's distribution business activities that are funded on the delivery side of the bill
2 would be available for comprehensive review. To the extent there is a need to advance
3 transformational, multi-year initiatives that can only be accomplished by phasing in
4 investments across several years, the multi-year rate plan is ideal. A budget for the
5 activities can be established, the base distribution rates can be set to match the budget,
6 and the utility can be launched to achieve the goals. But unlike a mechanism that
7 reconciles costs, this type of planning and cost recovery provides better signals to the
8 utility. Instead of the utility falling into financially-neutral spending patterns because it is
9 ratepayer money it is using under a reconciliation, the utility will experience the budget
10 as its own money at risk. That is, if the utility achieves the objectives under budget, the
11 utility is rewarded. Conversely, if the utility mismanages and exceeds the budget, the
12 utility's earnings suffer.

13 **Q. Why is this fair to all participants?**

14 A. If it is properly designed, the multi-year rate plan is fair to ratepayers because it caps
15 targeted spending at pre-determined reasonable levels. It also should be desirable to
16 policymakers because it advances the desired initiatives. Finally, it is fair to the utility
17 because it provides a reasonable opportunity for the utility to recover all of its costs of the
18 initiatives in a timely manner, while achieving a reasonable return for its shareholders.
19 Surely, the Company should have no legitimate complaint if it has a realistic opportunity
20 to recover its prudently-incurred costs, but has to accept the ordinary risks of running the
21 utility business along the way, including budget discipline.

1 **Q. What about allowing time for stakeholder input?**

2 A. Stakeholder input will continue to be important. Rhode Island has already recognized
3 this when it launched its Power Sector Transformation initiative. Numerous technical
4 sessions have been held. Other sessions have been held in the context of this Docket.
5 But this is only the first step. A multi-year rate plan requirement does not preclude
6 further stakeholder sessions.

7 **Q. The Company maintains that a PST Tracker is needed because of stakeholder input.
8 What is your view?**

9 A. One of the main reasons given by the Company for a PST Tracker is that they want
10 stakeholder input that could affect costs. But stakeholder input and planning are not
11 dependent upon the Company getting fully-reconciled cost recovery. Reconciliations
12 should be the exception, not the rule. Effective stakeholder input is achieved through
13 engagement, not assurances of cost recovery with no regulatory lag. It is the Company's
14 role and responsibility to invest in the initiatives that are prudent and support their request
15 for recovery with results.

16 **Q. How long should the multi-year rate plan be?**

17 A. The number of years should be at least three. This gives the utility two years of operating
18 under the budgets before it needs to file for another multi-year plan. During year three, it
19 operates under the third year's budget while the next plan is negotiated or litigated. It is
20 possible that a plan that runs five years could work. But when there are new initiatives
21 never experienced before, three years is a better place to start. Otherwise, technology and
22 the industry can advance ahead, leaving policymakers and the Company behind.

1 **Q. What is needed in the filing for financial data?**

2 A. It is critical that the Company file a comprehensive revenue requirement for each year of
3 the Rate Plan. This needs to be for more than just one rate year. It should reflect a real
4 plan of spending that can be justified in a granular manner, not mere inflationary
5 adjustments off the first year of projected costs. The filing should also include
6 projections for three years of capital spending for capital projects that are both eligible
7 and not eligible under the ISR. This would allow the Division, the Commission, and
8 other intervenors to evaluate the overall plan on an integrated basis.

9 **Q. What about projects and costs associated with “grid modernization”?**

10 A. The three-year business plan should also provide an integrated plan to advance the goals
11 of modernizing the grid. The objectives should be clear and there should be a transparent
12 way to evaluate how well multiple initiatives relate to each other.

13 **Q. Why would a capital plan for the three years be important, given the existence of the**
14 **ISR?**

15 A. The ISR provides review of plans that proceed one year at a time. While the Company
16 has provided multi-year forecasts, the focus is on the upcoming year. This can result in
17 skewed, short-term vision. The full plan of capital spending on the conventional
18 investments eligible for the ISR should be included along with the other investments and
19 spending for the transformational programs that need multi-year schedules. Annual cost
20 recovery for ISR-eligible projects would continue to be addressed in the annual ISR
21 process. The ISR planning process would be effectively embedded within and function
22 in parallel with the multi-year plan. However, all capital projects that are not otherwise

1 eligible for ISR treatment would be addressed in a parallel capital budget. In this way,
2 all capital spending over the three-year period would be addressed together.

3 **Q. Given the fact that the ISR is fully reconciling, how would the multi-year rate plan**
4 **address the concern that it does not result in a binding spending budget?**

5 A. This can be resolved through a capital efficiency incentive. There may be several
6 different ways to design an incentive that works in tandem with the ISR and the multi-
7 year plan. But the Division is considering a specific framework that would create
8 spending discipline.

9 **Q. How would the capital spending efficiency incentive operate?**

10 A. First, the Company would provide a three-year capital spending plan for all ISR eligible
11 projects for which it anticipates seeking approval under the ISR. This would be reviewed
12 and provisionally approved by the Commission. The spending budget would then be
13 tracked for the three years of the plan. The Division envisions a cumulative spending
14 budget in the aggregate. At the end of the three years, the three-year spending as it
15 actually occurred under the ISR is compared to the budget approved by the Commission
16 when approving the multi-year plan. To the extent the Company has achieved its
17 objective under the aggregate budget, savings can be kept or shared with ratepayers.
18 However, if the Company has exceeded the aggregate budget in circumstances where no
19 approved exceptions apply, the Company would be required to refund customers an
20 amount equal to the incremental increase in the revenue requirement during the rate plan
21 that was caused by the overspend.

1 **Q. How does it affect the Company's cost recovery after the plan is over?**

2 A. The Company would still be able to include the capital costs in rate base in the future,
3 provided that the spending was prudent, but it will have suffered the equivalent of a one-
4 year regulatory lag in partial cost recovery for missing the aggregate three-year budget
5 target, as measured at the end of the plan. This achieves a result which creates a virtual
6 budget for the three years, yet it does not affect the operation of the ISR under the statute.
7 There is no prohibition against exceeding the budget. Rather, it is simply an incentive
8 mechanism with a reward or penalty determined at the end of the rate plan period. As a
9 result, it provides spending discipline that does not currently exist without the multi-year
10 plan. It does not preclude the Company from doing what it needs to do to provide safe
11 and reliable service. The penalty would be financially analogous to creating a one or
12 two-year regulatory lag on a portion of the Company's capital cost recovery that exceeds
13 the budget. It would be similar to what happens across the country for utilities that make
14 investments in one year, but do not obtain additional rate relief until the next rate case
15 after the projects are in service.

16 **Q. What about the PST initiatives?**

17 A. As explained earlier, the rate case filing would contain spending forecasts for any
18 proposed PST initiatives. A budget would be created for each year of the plan, including
19 allowances to cover approved expenses for the initiatives. The Company would then
20 need to implement the initiative within the approved budget. Incentives also could be
21 included, but the basic effect is to require the Company to operate with spending
22 discipline, knowing that excess costs will not be fully reconcilable. Some modifications
23 and exceptions could be included for more complex initiatives, but the basic objective of

1 creating a budget and spending discipline would be addressed. In effect, the goal would
2 be to have the costs of the PST initiatives recovered through base distribution rates rather
3 than a tracker.

4 **Q. Are there any other features that would be included in a multi-year rate plan?**

5 A. We would expect so if a plan is negotiated in this case. For example, a multi-year rate
6 plan is flexible enough to incorporate any consensus items that may emerge from this
7 Docket 4780, such as electric transportation, electric heat and energy storage. In addition,
8 we anticipate that a multi-year rate plan negotiated as a part of this docket could have an
9 explicit re-opener for AMI investments that we recommend the Commission address
10 following submittal of the Company's proposed AMI study. What we have explained
11 here may not be the only way to achieve the balance of interests. But it illustrates the
12 parameters of how it can be done. In the end, the Division is adamant that the proposed
13 PST Tracker is not in customers interests and should not be approved by the
14 Commission.

15 **Q. Is it possible for a multi-year rate plan to be implemented?**

16 A. Yes. But the Division believes the only practical way that an effective multi-year rate
17 plan can emerge at this time is through a negotiated settlement.

1 **4. RATEMAKING RECOMMENDATION FOR THIS DOCKET IF THERE IS NO**
2 **MULTI-YEAR RATE PLAN**

3 **Q. How should the Commission treat PST and other investments in this docket if there**
4 **is no multi-year rate plan settlement in Docket 4770?**

5 A. To the extent a multi-year rate plan settlement cannot be negotiated and filed with the
6 Commission for approval, the Commission should direct the Company to implement the
7 PST initiatives not otherwise required in Docket 4770 that the Commission finds are in
8 the best in interest of ratepayers.

9 **Q. How should the Commission proceed if there is no multi-year plan?**

10 A. First, the Commission should make it clear to the Company that pre-approval and
11 automatic recovery of non-eligible ISR costs relating to all the PST initiatives will not be
12 allowed. The Commission should establish the principle that recovery of the costs of
13 most PST initiatives should be addressed in rate cases that set forth an integrated, multi-
14 year plan. The Commission should leave room to make exceptions as it deems sensible.
15 But the initiatives should not be addressed in special rate reconciliation processes that
16 isolate those programs from the rest of the distribution business. This would not preclude
17 technical sessions related to major initiatives that would benefit from Commission review
18 and stakeholder participation, but such technical processes should not be a process for
19 obtaining rate recovery through special mechanisms. They should be an evaluation of the
20 details, benefits, and desirability of integrated initiatives.

21 Second, if not already authorized through Docket 4770, the Commission should
22 require the Company to move forward with the GIS Enhancements, the AMI Study, and

1 the System Data Portal. But a PST tracker should not be used to provide cost recovery.
2 Instead, the Company should be directed to file another rate case, if needed, to embed any
3 costs in base distribution rates in the normal course of business for any of these activities
4 occurring in the future.

5 Third, to the extent performance-based incentive mechanisms have not already
6 been authorized in Docket 4770, the Commission should establish a framework for new
7 performance based ratemaking incentives to be implemented in the next rate case filed by
8 the Company, in such a way that they work in tandem with the Company's return on
9 equity allowance.

10 Finally, the Company should be directed to develop a comprehensive, integrated
11 plan for Grid Modernization that builds upon the initiatives that are recommended by
12 witness Greg Booth for the rate year. This plan, in turn, should be filed with the
13 Commission as a part of a multi-year rate case that includes an integrated business plan
14 with three years of revenue requirement data that allows a complete and thorough review
15 of the costs forecasted for each year of the plan, including all of the costs of the
16 distribution business not otherwise governed by statutory requirements, such as the ISR.
17 As a component of the plan, new initiatives can be included that provide the opportunity
18 to the Company for recovery of the costs through base rates in each year of the plan. The
19 Commission should place a deadline on the Company for the filing of the multi-year plan
20 no later than the first half of 2020 for new rates to take effect no later than the first
21 quarter of 2021. This schedule will allow enough time for planning and continued
22 stakeholder input on the PST and Grid Modernization initiatives, including AMI.

1 Once the first multi-year rate plan is in place, the Company can be placed on a three-year
2 schedule going forward. During the interim, however, the Commission must be clear that
3 the company should be undertaking any projects it believes are prudent and cost-
4 effective, whether conventional or PST.

5 **Q. Does the Division believe the Commission has the authority to require a multi-year**
6 **rate plan by a specified date?**

7 Yes. While the Company traditionally has been left with the discretion to commence rate
8 cases on its own schedule, this has been by default or regulatory tradition. There are no
9 statutory provisions or other legal requirements of which we have been made aware that
10 create a limitation or requirement that precludes such an action. The Division believes
11 the Commission has broad supervisory authority over the rates of the utility that permits
12 it to investigate rates and require rate filings relating to the costs of the business.

13 **Q. How should the Commission address AMI?**

14 A. To the extent it has not already been authorized in Docket 4770, the Commission should
15 direct the Company to complete the AMI study and file it with the Commission for
16 review prior to implementation. As described elsewhere in the testimony, the costs of the
17 study should be addressed in the rate year of this rate case, as recommended by the
18 Division in the testimony of Mr. Ballaban in Docket 4770. If deployment is ultimately
19 approved by the Commission, the costs of deployment should be included in base rates as
20 a part of the multi-year rate plan filing made during the first half of 2020. But
21 implementation should not be delayed in order for the means of cost recovery to be
22 engraved in regulatory stone before the Company advances prudent programs. As the
23 Division's witness Ballaban testifies in Docket 4770, National Grid did not wait for all

1 regulatory cost approvals to be in place before launching the Gas Business Enablement
2 program that achieved higher proportional benefits to New York than Rhode Island. The
3 program was launched and the costs allocated to all jurisdictions. Likewise, it should not
4 wait for favorable cost recovery to be approved in all other jurisdictions to be in place
5 before beginning the process in Rhode Island, should the Commission find deployment of
6 AMI appropriate and prudent.

7 **Q. Are there any particular components that the Division considers important to**
8 **include in the AMI study?**

9 A. Yes. The Division has identified two distinct opportunities to significantly reduce the
10 potential cost of AMI deployment for ratepayers: alternative ownership models for meter
11 infrastructure and shared communications systems. While deployment of AMI without
12 either of these innovative approaches may still provide ratepayers greater benefits than
13 costs, the Division argues the AMI study should examine each of them. In addition, the
14 Division will request that it be involved in regular monthly meetings on the study
15 process.

16 **5. NATIONAL GRID'S PERFORMANCE INCENTIVE MECHANISM PROPOSAL**

17 **a. National Grid's Proposal**

18 **Q. Why has the Company proposed PIMs?**

19 A. National Grid notes that it has developed PIMs to advance Rhode Island's energy policy
20 goals, provide new benefits to customers, and reward utility performance in delivering

1 key programs.⁸ The Company claims that the current regulatory framework “is not
2 sufficient to drive innovative utility performance,” and that new compensation
3 mechanisms are needed to align utilities’ “financial interests with broader policy goals
4 and customer outcomes that expand beyond core performance obligations.”⁹

5 **Q. What type of PIMs has the Company proposed?**

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

8 **Q. What are the Company’s proposed PIMs based on?**

9 A. National Grid states that it considered the PIM recommendations in the Power Sector
10 Transformation Report. The Company views the PIMs proposed in this docket as a “first
11 step in a broader evolution of the regulatory framework,” suggesting that the proposed
12 PIMs could be modified or expanded over time.¹⁰

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

14 A. Yes. Since 1990 the Company has had a shareholder incentive mechanism for its energy
15 efficiency programs. The energy efficiency PIM was developed through negotiations
16 with the Company in the DSM Collaborative, and it has been modified several times in
17 the past. National Grid also has a set of PIMs related to its service quality plans. The
18 Company is also allowed to earn shareholder incentives for long-term renewable

⁸ PST Panel Direct Testimony, p. 81, lines 15-19.

⁹ PST Panel Direct Testimony, p. 83, lines 9-14.

¹⁰ PST Panel Direct Testimony, p. 84, lines 1-9.

1 contracts, distributed generation contracts, and the Renewable Energy Growth program,
2 as determined by legislation.

3 **Q. Does National Grid’s proposal for new PIMs include any penalties for**
4 **underperformance?**

5 A. No. All of the PIMs proposed by the Company include only rewards for performance
6 related to the relevant targets. National Grid notes that the reward-only PIMs are
7 appropriate because they are related to new customer benefits, and they “reflect new
8 areas of accountability for the Company that expand beyond its core obligations.”¹¹

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

10 A. The Company has proposed two capital efficiency PIMs:

- 11 • The Complex Capital Projects Capital Cost Incentive. The Company is proposing
12 to compare actual final capital costs to a baseline estimate of capital costs that
13 were used to review and approve the project. Any savings relative to the baseline
14 would be shared equally between customers and shareholders, and any costs
15 above the baseline would be borne by the Company’s shareholders.
- 16 • The Construction Costs per Mile Productivity Incentive. The Company has not
17 fully developed this metric. National Grid plans to develop a metric based on the
18 construction cost per mile for distribution projects. The Company notes that it will
19 propose a baseline and targets for this PIM in its FY 2020 Electric ISR Plan
20 filing.¹²

¹¹ PST Panel Direct Testimony, January 12, 2018, page 85, lines 4-9.

¹² PST Panel Direct Testimony, January 12, 2018, page 86, lines 10-14.

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

2 A. National Grid’s proposed System Efficiency PIMs are summarized in Table 1.¹³

3 **Table 1. 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

4

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

7 A. The purpose of the FCM Peak Demand Reduction PIM is to encourage the Company to
8 reduce the annual forward capacity market (FCM) peak demand to reduce Narragansett
9 Electric’s share of annual FCM costs. The metric for this PIM will be the weather-
10 normalized FCM peak demand. The baseline for this PIM is the actual weather-
11 normalized FCM peak demand of the previous year, beginning with 2018. The
12 Company’s proposed MW targets are presented in Table 2.¹⁴

13 **Table 2. 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

14

¹³ PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 15 (Bates 18)

¹⁴ PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 15 (Bates 18)

1 These annual FCM targets include the savings that the Company expects to achieve
2 through energy efficiency, distributed generation, volt-var optimization (VVO), and
3 storage.¹⁵ Consequently, the MW savings targets for the FCM PIM only represent
4 additional savings of 5 to 6 MW each year.

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

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

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

¹⁵ Attachment DIV 25-5.

1 Company's proposed MW savings targets in 2019 are relative to the transmission peak
2 values in 2018, while the savings achieved in 2020 are relative to the transmission peak
3 values in 2019. The Company's proposed MW targets and basis point incentives for this
4 PIM for 2019 are presented in Table 3.¹⁶

5 **Table 3. 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

6
7 **Q. Please summarize the DER PIMs proposed by National Grid.**

8 A. National Grid's proposed DER PIMs are summarized in Table 4**Error! Reference**
9 **source not found.**¹⁷

¹⁶ PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 15 (Bates 18)

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

1

Table 4. 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

2

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

4 A. National Grid’s proposed network support services PIMs are summarized in Table 5.¹⁸

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

1

Table 5. 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

2

3 **Q. Please summarize the total incentives that National Grid could potentially earn in**
4 **2019 from all its proposed PIMs.**

5 **A.** These are summarized in Table 6.

6 **Table 6. 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

7

1 **b. Critique of National Grid’s Proposal**

2 **Q. Please describe your concerns with National Grid’ proposed Capital Efficiency**
3 **PIMs.**

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

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

14 **Q. Please describe your concerns with National Grid’s proposed FCM Peak Demand**
15 **Reduction PIM.**

16 A. We have concerns regarding the baseline, targets, and incentives associated with National
17 Grid’s proposed FCM PIM. First, National Grid proposes to reduce peak demand on a
18 year-over-year basis. These targets were developed in relation to a baseline forecast of
19 peak demand, but converting them to year-over-year targets divorces them from the
20 baseline, rendering it meaningless.¹⁹ The use of a sound baseline in setting and measuring

¹⁹ 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

1 targets is critical, as it captures the effects of many other drivers of peak demand
2 reductions. If these other factors are not accounted for in setting and measuring PIM
3 targets, then the Company might be rewarded for peak demand reductions that are not a
4 result of its actions (or not rewarded despite utility actions that successfully reduce FCM
5 peak demand.)

6 Second, the Company did not propose targets that provide a sufficient degree of
7 certainty that they will be achieved due to Company effort, rather than other factors.
8 When a forecast is used as a baseline for a PIM, it is often appropriate to establish a
9 “deadband” around the forecast. A deadband is a region around the target within which
10 the Company would not earn a reward (or incur penalties). The concept of a deadband is
11 often used to account for uncertainty regarding the target or to allow for some deviation
12 from the target due to factors outside of utility control.²⁰ Setting PIM targets outside of a
13 deadband helps to ensure that the utility is not provided incentives for outcomes that it is
14 not responsible for. The Company’s proposal would result in PIM targets that fall within
15 a reasonable deadband and so have a reasonable likelihood of being achieved without any
16 additional effort by the Company.

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.

²⁰ Melissa Whited, Tim Woolf, and Alice Napoleon, “Utility Performance Incentive Mechanisms: A Handbook for Regulators” (Synapse Energy Economics, March 9, 2015), http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

1 **Q. Please describe your concerns with National Grid’s proposed Transmission Peak**
2 **Demand Reduction PIM.**

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

11 This is the same problem described above for the FCM PIM. However, unlike the
12 FCM peak demands, the Company does not have a forecast of monthly transmission peak
13 demands.²¹

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

19 As noted above, it is often appropriate to establish a “deadband” around the
20 forecast within which there would be no reward or penalties for performance. Deadbands

²¹ DIV 25-14

1 are useful for mitigating uncertainty regarding the target and to allow for some deviation
2 from the target due to factors outside of utility control.²² PIM targets should be designed
3 to fall outside of such a deadband, to ensure that the utility is not provided incentives for
4 outcomes that it is not responsible for. The Company’s proposal to use a historical year
5 for the baseline, instead of a reasonable forecast, has resulted in Transmission PIM
6 targets that might be so easy to meet that they will not provide any benefits to customers.

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

15 **Q. Please describe your concerns with National Grid’s proposed Off-Peak Charging**
16 **Rebate Pilot PIM.**

17 A. In general, we agree with the Company’s goal of encouraging customers to charge their
18 EVs during off-peak hours, and that this could be an important way to transition EV
19 customers to TVR in the future. However, we do not think that participation in Off-Peak
20 Charging Rebate Pilot is a very robust metric for this purpose. Customer participation in

²² Whited, Woolf, and Napoleon, “Utility Performance Incentive Mechanisms: A Handbook for Regulators.”

1 the rebate program does not necessarily mean that customers will change their charging
2 patterns.

3 In addition, we are not convinced that the Company's proposed pilot is the best
4 way to promote the cost-effective adoption of EVs. We prefer an EV metric that is more
5 closely tied with one of the primary objectives for promoting EVs: the reduction of
6 greenhouse gases.

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

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

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

1 implement programs in the most cost-effective way, and will protect customers in
2 the event that the demand response program net benefits are small or negative.

- 3 • Electric Heat Initiative. We prefer that the magnitude of this incentive be based on
4 a shared savings approach. This will encourage the Company to design and
5 implement programs in the most cost-effective way, and will protect customers in
6 the event that the initiative's net benefits are small or negative.
- 7 • Electric Vehicles. One of the primary policy goals for promoting EVs is to reduce
8 greenhouse gas emissions. Therefore, we prefer a metric that is more directly tied
9 to this policy goal.
- 10 • Behind-the Meter Storage. We are concerned that the Company's behind-the-
11 meter storage program is not sufficiently defined at this time. Also, for the many
12 customers that do not have time-varying rates, behind-the-meter storage is not
13 likely to be economical. Even for those customers with TVR, the Company has
14 not demonstrated that behind-the-meter storage will provide net benefits to
15 customers. We prefer that the magnitude of any incentive be based on a shared
16 savings approach; which will encourage the Company to design and implement a
17 program in the most cost-effective way, and will protect customers in the event
18 that the program net benefits are small or negative.
- 19 • Company-Owned Storage. We are concerned that the Company-Owned Storage
20 PIM is not justified on economic grounds. The Company's BCA indicates that
21 company-owned storage has a benefit-cost ratio of 0.45.²³ In addition, we prefer
22 that the magnitude of any incentive be based on a shared savings approach; which
23 will encourage the Company to design and implement a program that is cost-
24 effective, and will protect customers in the event that the program net benefits are
25 small or negative.

²³ Schedule PST-1, Chapter 7, Energy Storage, page 6 of 9.

1 **Q. Please describe your concerns with National Grid’s proposed Network Support**
2 **Services PIMs.**

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

- 6 • AMF Customer Engagement and Deployment. This PIM is premature, given that
7 the Commission has not yet approved system-wide deployment of AMF.
- 8 • VVO Pilot Delivery. The Company has clearly demonstrated that VVO will
9 improve the efficiency with which the electricity grid is operated and provide
10 significant net benefits to customers.²⁴ While VVO technologies might be
11 described as relatively new, they fall within the Company’s core performance
12 obligations, and thus do not warrant a PIM. In addition, VVO technologies are not
13 necessarily foundational to power sector transformation.
- 14 • Interconnection Support – Time to ISA. The Company already has a legislative
15 requirement and performance standards to complete certain aspects of the
16 interconnection process for distributed generation in a timely fashion.²⁵
- 17 • Interconnection Support – Estimate Versus Actual Cost. Interconnecting
18 distributed generation customers at a reasonable, low cost is already a part of the
19 Company’s core performance obligations, and thus does not warrant a PIM.

²⁴ As documented in Attachment DIV 3-20.

²⁵ 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.

1 **6. ELECTRIC TRANSPORTATION INITIATIVE**

2 **Q. Have you reviewed the Company’s proposed Electric Transportation Initiative?**

3 A. Yes. We have reviewed it and have comments on both program structure and budget.

4 **Q. How is the Company’s proposed Electric Transportation Initiative related to state**
5 **energy objectives?**

6 A. In Rhode Island, as in many northeastern states, greenhouse gas (GHG) emissions from
7 transportation represent a plurality of total emissions. Nearly 40 percent of total GHG
8 emissions come from transportation. To address these emissions, the Executive Climate
9 Change Coordinating Council (EC4) greenhouse gas emissions reduction scenario
10 identifies the electrification of 34% of on-road vehicle miles traveled by 2035 and 76%
11 by 2050. In a separate exercise, the Rhode Island Zero Emission Vehicle (ZEV) Draft
12 Plan calls for growing EV adoption more than 40-fold (from approximately 1,000 to
13 43,000) by 2025. As these initiatives indicate, electrification of personal and fleet
14 vehicles is a necessary step to achieving Rhode Island’s decarbonization goals.

15 **Q. What general observations do you offer in response to the company’s proposed**
16 **electric transportation initiative?**

17 A. We have four general observations:

- 18 • First, over the coming decade the adoption of electric vehicles will, if not correctly
19 managed, increase stress on the distribution system. Accordingly, the Company
20 should be required to use rigorous distribution system planning to ensure that the
21 location of electric vehicle charging infrastructure is optimally integrated into the
22 system’s existing constraints.

- 1 • Second, widespread adoption of electric vehicles will tend to increase the importance
2 of time-varying rates to encourage new vehicle load to be most economically
3 integrated into the existing distribution system at off-peak times.
- 4 • Third, the Company should tailor its proposal to leverage the forthcoming Mitigation
5 Plan to be issued by the Rhode Island Division of Environmental Management as a
6 part of the Volkswagen Environmental Mitigation Trust Agreement .
- 7 • Fourth, the Company should demonstrate in its proposals a clear strategic approach to
8 how the utility can best engage in an activity – transportation – well outside of its
9 traditional realm.

10 **Q. Do you have any additional strategic recommendations to offer on program design**
11 **for electric vehicle charging infrastructure?**

12 A. Yes. One approach that is not sufficiently emphasized in the Company's proposal is the
13 potential for public transit buses to lead near-term electric vehicle adoption, providing
14 significant greenhouse gas emission reductions from conversion of diesel buses to
15 electricity as well as significant local environmental and health benefits to neighborhoods
16 through which buses travel, which are often home to income-eligible customers. In
17 addition, Rhode Island Public Transit Authority (RIPTA) is a quasi public entity with a
18 clear public benefit purpose. It is uniquely suited to leverage any investment of funds
19 from ratepayers for societal benefit.

20 **Q. Please elaborate on why transit electrification is important.**

21 A. The Company has correctly identified fleet owners as an important potential source of
22 early electric vehicle adoption. Fleet owners can more centrally control procurement

1 decisions to purchase electric vehicles and can more systematically match charging needs
2 with the appropriate number of charging ports. In a presentation to the Executive Council
3 on Climate Change, Rhode Island Public Transit Authority described its general vision to
4 electrify its fleet of buses. Using a major fleet to lead electrification would remove diesel-
5 powered buses from the road; improve local air quality, which currently has a negative
6 impact on asthma rates; and improve the quality of life in income eligible neighborhoods.
7 Exhibits 5 and 6 show the routes of some of the most heavily travelled buses in
8 Providence and local asthma rates.

9 **Q. How should the Company's proposal be altered to incorporate public transit buses**
10 **as a priority?**

11 A. The Company has included \$175,000 in EVSE rebates and \$400,000 in capital for DCFC
12 dedicated to public transit buses. The use of these O&M and capital funds should be as
13 flexible as possible to meet the needs of any project RIPTA chooses to propose to its
14 Board and stakeholders.

15 **Q. Have you reviewed the major components of the Company's Electric**
16 **Transportation Initiative?**

17 A. Yes. We have reviewed each of the components the Company has proposed: Off Peak
18 Charging Rebate Pilot, Charging Station Demonstration Program, Discount Pilot for
19 Direct Fast Charging Station Accounts, Transportation Education and Outreach,
20 Company Fleet Expansion, and Initiative Evaluation.

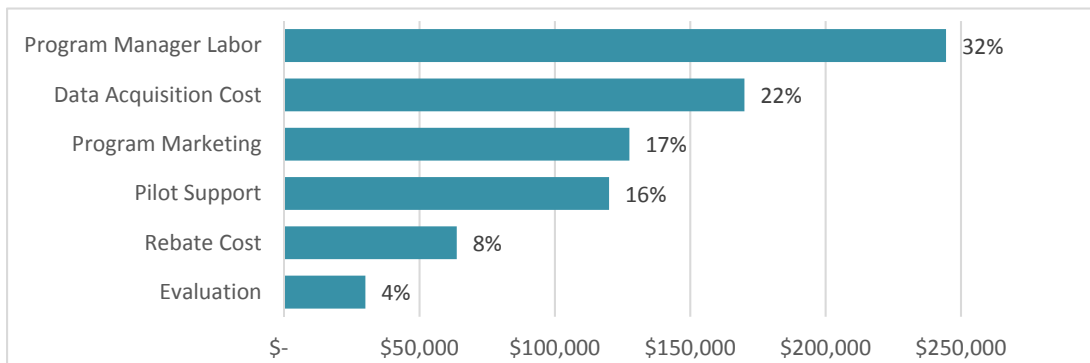
1 **a. Off-Peak Charging Rebate Pilot**

2 **Q. What are your findings with respect to the Off-Peak Charging Rebate Pilot?**

3 A. Although the Company seeks to achieve several important objectives through the Off-
4 Peak Charging Rebate Pilot – chief among them encouraging electric vehicle charging at
5 off-peak times -- there are three important areas in which the proposal could be
6 improved: cost, submetering technology, and rate structure.

7 **Q. What are your concerns regarding the cost of the Off-Peak Charging pilot?**

8 A. We are concerned that the costs of the program are weighted toward program
9 management, data acquisition, evaluation, and marketing. Of the proposal’s total cost of
10 \$755,000, only \$64,000 (8%) represents actual rebate payments to customers, as shown
11 in the graph below.²⁶



12

13 In essence, the Company is proposing a \$690,000 pilot program without significant
14 justification or detail. Some of these costs are highly questionable. For example, the
15 Company expects marketing costs to be a recurring cost of \$150 per customer, year after

²⁶ Attachment DIV 3-4-1

1 year, even for customers who have already enrolled in the pilot. As another example,
2 “pilot support” is \$40,000 per year and again includes marketing. Further, “pilot support”
3 includes call center capabilities that should be a part of the core enterprise.

4 **Q. Please describe your concerns regarding submetering technology.**

5 A. The second largest cost category is related to data acquisition, at an estimated cost of
6 \$200 per customer per year.²⁷ Although the technology to be used for measuring EV
7 charging has not yet been selected, the costs estimated by the Company are similar to
8 those associated with third-party devices (such as stand-alone submeters, submeters
9 integrated into Level 2 chargers, or devices that plug into the car’s on-board diagnostics.)

10 The need for additional submetering equipment (and ongoing data/communication costs)
11 is a key barrier to cost-effectiveness, both at the pilot stage and under a wider roll-out.
12 Another option exists, however, which could prove to be much more cost-effective and
13 avoid stranded costs of submetering technology.

14 **Q. What other options are available for separately measuring EV charging load?**

15 A. Load disaggregation technology can be applied to data collected by advanced meters to
16 identify EV charging load, particularly where Level 2 chargers are used. For example,
17 several municipal utilities in Massachusetts use Sagewell’s “Bring Your Own Charger®”
18 program, which relies on load disaggregation of AMI data.²⁸ The key benefit of using

²⁷ Attachment DIV 3-4-1. Note that in response to DIV 1-37 and DIV 10-27, the Company states that it has not yet determined what technology the Company will use to separately monitor the EV load of customers that participate in this pilot.

²⁸ See Belmont’s program website here: http://www.belmontlight.com/energy-solutions/Electric_Vehicles.php?id=69 and Braintree’s program website here: <http://www.braintreedriveselectric.com/>.

1 AMI meters is that the meters would be used and useful even after the pilot ends, and
2 data could be collected using the Company's current AMR technology, rather than
3 requiring additional communications technologies. Second, if the Commission approves
4 the Company's proposal to install AMF, then any advanced meters installed for the Off-
5 Peak Charging pilot represent fewer meters the Company would have to install when
6 implementing AMF.

7 **Q. Does the Company's AMF proposal include advanced meters capable of load**
8 **disaggregation?**

9 A. Yes. The Company states that its proposed deployment "will use the latest generation
10 meter technology, which includes new features such as load disaggregation and locational
11 awareness."²⁹ For these reasons, we recommend that instead of deploying special purpose
12 devices for this pilot, the Company should instead deploy AMI compatible meters which
13 could provide the necessary functionality to distinguish electric vehicle load and, in the
14 event the Commission approves it, would be compatible with statewide AMI
15 deployment.³⁰

16 **Q. Please describe your concerns regarding the structure of the off-peak rebate.**

17 A. The Company is offering a simple rebate (i.e., a discount from normal pricing) for the
18 pilot, rather than a time-of-use type of rate with both on-peak and off-peak prices. While
19 a pure rebate structure may be attractive to customers, it could be confusing and counter-
20 productive in the long-term if the Company intends to offer time-of-use rates once AMI

²⁹ PST-1, Chapter 4, page 19. Also see Response to Division 2-28 for the Company's explanation of the capabilities of load disaggregation.

³⁰ A variety of vendors such as Sagewell can apply load disaggregation algorithms to data collected by advanced meters to identify Level 2 charging behavior and provide customers with incentives to charge off-peak. These

1 is rolled out across the state. That is, it may be difficult to convince customers to switch
2 from a risk-less rebate structure to a time-of-use rate in the future.

3 In addition, a time-of-use rate (with both higher on-peak rates and lower off-peak
4 rates) provides a more efficient price signal than a rebate-only rate. Under a time-of-use
5 rate, customers would be penalized with a higher rate for charging on-peak and rewarded
6 with a lower rate for charging off-peak. Such a price signal is more closely aligned with
7 actual costs on the system. Therefore, for consistency, simplicity, and efficiency, we
8 recommend that the Company implement a time-of-use rate that is likely to be similar to
9 that offered to customers in the future.

10 **Q. Do you have specific adjustments to make to the Company's proposal?**

11 A. Yes. In addition to potentially reducing the costs for data acquisition by using AMI (as
12 discussed above), we recommend that the Company's proposal to include \$127,500 for
13 marketing (\$255 per customer)³¹ be reduced to \$25 per customer. Rather than conducting
14 conventional marketing campaigns to reach 500 electric vehicle owners, the Company
15 should work with the Division to develop a structured approach to identify electric
16 vehicle purchases.

17 **Q. Is that your only adjustment?**

18 A. No. In addition, the proposal includes \$120,000 in "Pilot Support". This includes call
19 center capabilities, marketing, and customer support. These functions should be a part of

31

1 the core enterprise and leverage the capabilities of the Company, not require an additional
2 expense.

3 **b. Charging Station Demonstration Program**

4 **Q. What are your findings with respect to the Charging Station Demonstration**
5 **Program?**

6 A. The Charging Station Demonstration Program begins from an assumption that remains
7 unproven: that a lack of charging stations is the most salient barrier affecting Rhode
8 Island electric vehicle adoption. The Company claims on page 103 of PST Book 1 that
9 “lack of accessible charging stations is a major barrier to consumer consideration of
10 EVs.” However, the Company offers no evidence to support that this assertion is
11 affecting Rhode Island electric vehicle adoption rates. There are other possible
12 explanations. For example, the cost of electric vehicles could be an obstacle for some
13 drivers. Similarly, barriers within the car dealer distribution chain may influence car-
14 purchasers to opt for conventional internal-combustion engine vehicles rather than
15 electric vehicles.

16 **Q. How many electric vehicle charging ports are needed in Rhode Island to meet policy**
17 **goals?**

18 A. Although there is no accepted number of charging ports necessary to spur EV adoption,
19 some measures of the necessary ratio of EVs to charging ports do exist. For example, the
20 Company cites a report by NREL that suggests Rhode Island would need 2,100 ports in
21 public locations and workplaces to support 43,000 EVs and meet Rhode Island’s ZEV
22 target. That translates to approximately 20 electric vehicles for every one port. Currently

1 the state of California, a recognized leader in electric vehicle adoption, has 22 EVs per
2 Level 2 port and 169 EVs per DC Fast Charging port (DCFC).

3 **Q. How does Rhode Island compare to these ratios?**

4 A. According to data provided by the Company, Rhode Island currently exceeds the ratio of
5 charging ports to electric vehicles identified by NREL, as well as that obtained by
6 California. Rhode Island has 4.6 EVs per Level 2 charging port and 40 EVs per DC fast
7 charger (DCFC).³² This suggests that Rhode Island already has a large number of ports
8 for each electric vehicle, and that the number of electric vehicles in Rhode Island could
9 more than triple to 3,500-4,000 before the ratio of EVs to charging stations would reach
10 the ratio currently observed in California. Based on this comparison, simply installing
11 more charging ports appears to be a capital-intensive approach to achieving statewide
12 electric transportation.

13 **Q. How well utilized are the existing charging ports owned by National Grid?**

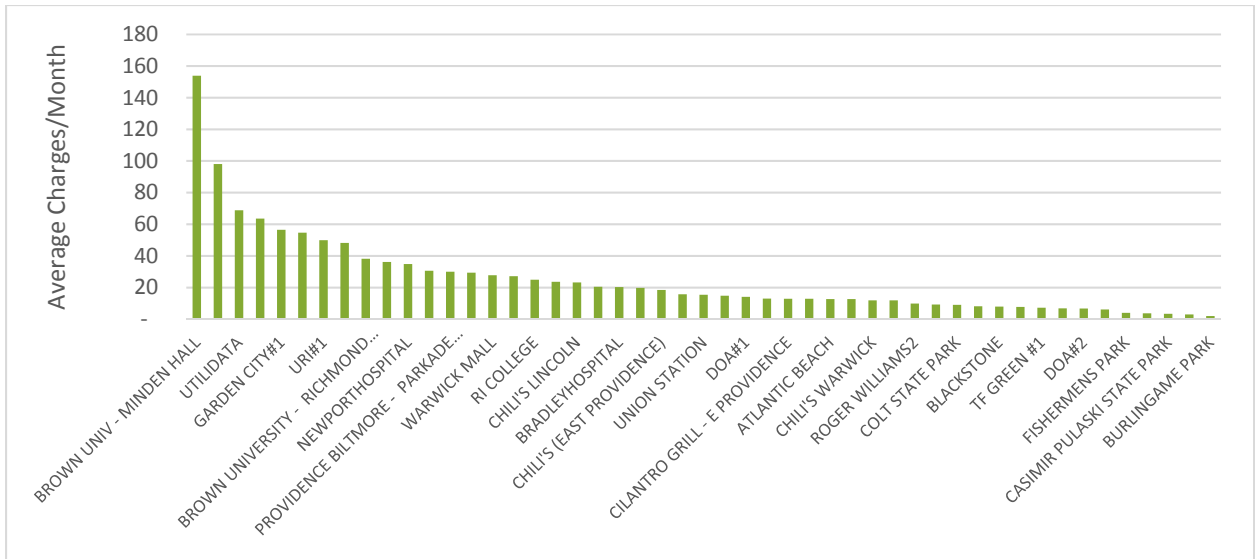
14 A. National Grid currently owns 49 charging stations (with 102 ports) across the state.³³ The
15 Company reports that 47 of these 49 stations provide drivers with charging service at no
16 cost.³⁴ Despite offering free charging, many of the ports are currently underutilized. On
17 average, in 2017, these charging stations saw less than one charge per day. Because most
18 of these stations have two ports, this implies that each charging port was used less than
19 once every two days.³⁵ This is shown in the graph below.

³² Attachment DIV-3-2-1

³³ PST Book 1, Bates, p. 101

³⁴ Division 1-21 (c)

³⁵ Based on analysis of data provided in Attachment DIV 10-41-2



1

2

3 **Q. Are you suggesting that Rhode Island does not need additional charging stations?**

4 A. No. In many respects, the question before the Commission is not whether more stations
 5 will one day be needed, as they certainly will be one day, but whether over the next three
 6 years limited funding is best spent on charging stations as a means to advance electric
 7 transportation. Where additional charging stations are installed, they should be installed
 8 strategically to provide the most benefit at the lowest cost to customers.

9 **Q. In what manner could the electric transportation proposal be more strategic?**

10 A. There are several ways that the electric transportation initiative could be designed to be
 11 more strategic. First, EV charging station site selection should be coordinated with the
 12 Heat Map capability to be deployed later in 2018 in order to ensure that new charging
 13 stations locations minimize the impact on the distribution system. Second, the number
 14 and type of charging stations should be optimized with the forthcoming investment from
 15 the Volkswagen Settlement funding. Third, the Company proposes to own and operate 4

1 DCFC stations. These may not be needed based on developments in the private and
2 public sector among other vendors moving to develop these resources, particularly given
3 that the Company proposes to temporarily eliminate the demand charge for these
4 customers, which can be a key barrier to the profitability of these charging stations.

5 **Q. Do you have any adjustments to make to the proposal budget in the Charging**
6 **Station Demonstration program?**

7 A. Yes. We recommend an adjustment for \$252,000 in O&M expenses over the three years
8 to eliminate the duplicative marketing function with the exception of a dedicated website
9 that would provide customers with information on rates and rebates available for EV
10 customers.³⁶ In addition, we recommend elimination of \$1,226,000 in capital costs
11 pertaining to the utility-owned DCFC network.

12 **c. Discount Pilot for DC Fast Charging Accounts**

13 **Q. Have you reviewed the Company's proposed discount pilot for DC Fast Charging?**

14 A. Yes. The Company proposes to implement a time-limited discount on electric bills for
15 dedicated DC fast charging station accounts established during the initial period of EV
16 market development. This discount would be reflected in a per-kW monthly bill credit
17 that would offset the customer's distribution demand charge.³⁷ The discount would be

³⁶ See, for example, Southern California Edison's EV Rate Assistant website here:
<https://www.sce.com/wps/portal/home/residential/electric-cars/rates-charging-options/EV-Rate-Assistant/> and
the utility's overall EV information portal here: <https://www.sce.com/wps/portal/home/residential/electric-cars/charging-and-installation/EV-Rate-Assistant/>

³⁷ PST Panel Book 1, Bates Number 108.

1 applied for three years from the start of service, after which the Company would evaluate
2 the impact of the discount program.³⁸

3 **Q. What is your assessment of the Company's proposal?**

4 A. In general we support this proposal, as demand charges can be a significant barrier to the
5 profitability of DC Fast Charging stations. However, we do have some concerns that the
6 sudden cessation of the credit after three years will produce dramatic changes to these
7 customers' bills. Therefore we recommend that the Company phase out the demand
8 charge credit over time to allow customers to adjust and prevent rate shock. In addition,
9 we recommend that the Company include a clearly itemized credit value on each
10 customer's bill,³⁹ together with information explaining the phase-out timeline and
11 eventual expiration of the credit.

12 **d. Company Fleet Expansion**

13 **Q. Have you reviewed the Company's Fleet Expansion proposal?**

14 A. Yes. The Company is proposing to add 12 new plug-in hybrid heavy-duty trucks⁴⁰ to its
15 Rhode Island fleet for use in electric and gas operations at a cost of \$584,000. The
16 Company states that such an investment would enable it to be "a more effective advocate
17 and advisor for customers considering electric vehicle options because of what the
18 Company will learn from owning and operating these vehicles."⁴¹

³⁸ PST Panel Book 1, Bates Number 109.

³⁹ This recommendation is similar to a "shadow bill" concept.

⁴⁰ Response to DIV 10-34 (c)

⁴¹ Response to DIV 10-34 (e)

1 **Q. What are your observations regarding the Company’s Fleet Expansion proposal?**

2 A. The Company’s Fleet Expansion proposal is not justified for several reasons. First, the
3 Company has already begun electrifying its own fleet, and yet “has not found these
4 vehicles to be competitive, on a cost or performance basis, with the Company’s standard
5 diesel-powered vehicles.”⁴² The Company has not explained why it would be in
6 ratepayers’ interests to add additional electric trucks to its fleet if they are not competitive
7 on a cost or performance basis relative to diesel trucks. Second, given that the Company
8 already has some electric trucks in its fleet, it is not clear what lessons would be learned
9 from adding additional electric trucks to the fleet.

10 Finally, the Company has failed to adequately examine alternatives. Specifically, the
11 Company states that it “has not investigated whether electrifying vehicles in customers’
12 fleets would provide greater benefits than electrifying vehicles in its own fleet.”⁴³

13 **Q. What do you recommend?**

14 A. We recommend that the Company’s proposal be deferred in favor of projects with a
15 greater impact and benefit for ratepayers. Therefore, we recommend an adjustment to
16 eliminate \$384,000 in cumulative expenses and \$200,000 capital costs.

⁴² Response to DIV 10-9.

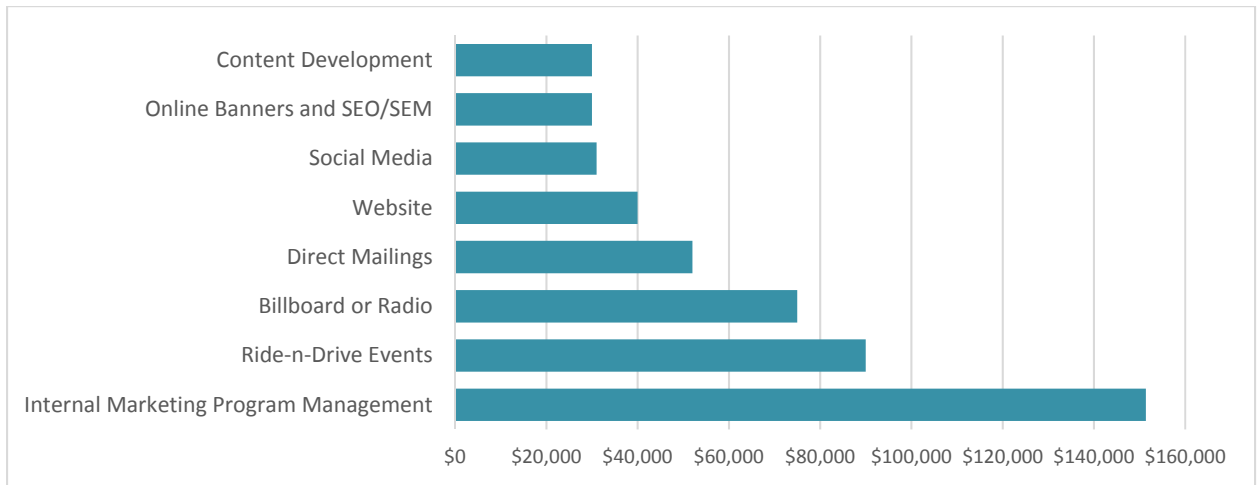
⁴³ Response to DIV 10-34 (e)

1 e. **Education and Outreach**

2 **Q. Do you have any findings on the Company’s Education and Outreach proposal?**

3 A. Yes. The Company has proposed to spend \$499,397 over three years. This effort is
4 primarily dedicated to mass market media: social media, billboards, radio, mailers.⁴⁴
5 None of these media are focused on people on the cusp of car purchase.

6 **Figure 1. Three-Year Cost of Education and Outreach⁴⁵**



7
8 **Q. What do you propose as an alternative marketing strategy?**

9 A. Instead of the Company’s scatter-shot approach, we recommend creation of a \$600,000
10 Strategic Electrification Education and Outreach Fund. This would be funded with the
11 \$499,000 from the EV program and the \$100,000 in gas and oil outreach from the
12 Electric Heat Initiative. The Company would consult with DPUC to develop and file a
13 Plan with PUC for comment by stakeholders. The funding would be contingent on
14 approval of a coherent strategy, rather than isolated “marketing” expenses. That strategy

⁴⁴ Attachment DIV 3-4-1

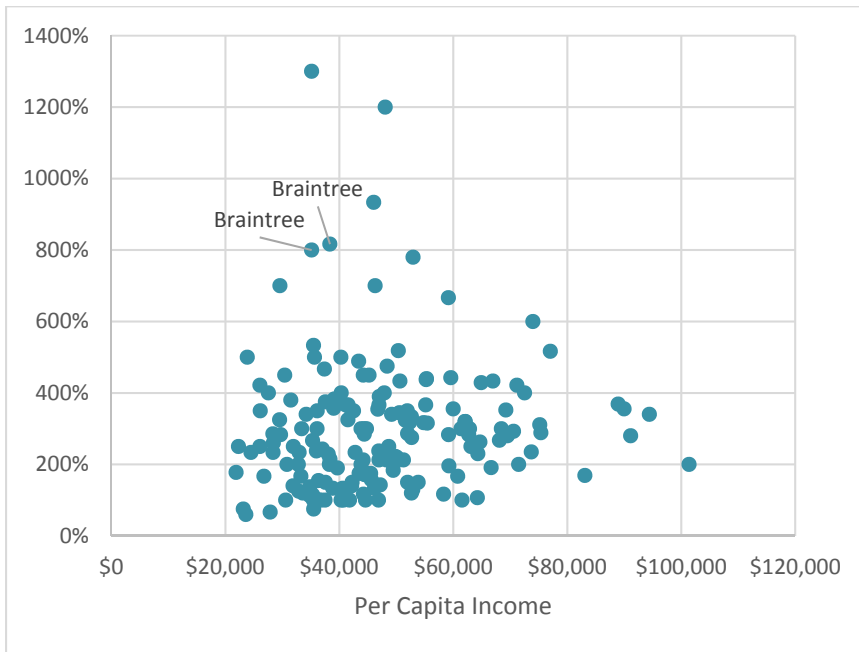
⁴⁵ Attachment DIV 3-4-1

1 should focus on building long-term distribution channels rather than short-term
2 conventional marketing. In addition, we recommend that the Company consider enlisting
3 third parties who specialize in turnkey marketing and community outreach efforts. For
4 example, Braintree Electric and Light Department in Massachusetts has significantly
5 increased adoption of EVs since hiring an energy services firm that specializes in EV
6 customer acquisition in 2016.⁴⁶ In addition to targeted outreach and marketing, the firm
7 also negotiates discounts for customers at auto dealerships. The chart below shows the
8 percentage increase in EVs in Massachusetts by zip code from 2015 to 2018 with
9 Braintree zip codes highlighted.⁴⁷

⁴⁶ Braintree Electric and Light Department hired the firm Sagewell for this effort. See: Daniel Libon, “Braintree Group Encouraging Residents to Switch to Electric Vehicles,” *Patch*, August 30, 2016, <https://patch.com/massachusetts/braintree/braintree-group-encouraging-residents-switch-electric-vehicles>.

⁴⁷ Analysis using American Community Survey income and population data, and Center for Sustainable Energy (2018). Massachusetts Department of Energy Resources Massachusetts Offers Rebates for Electric Vehicles, Rebate Statistics through March 31, 2018, <https://mor-ev.org/program-statistics>

1 **Figure 2. Percentage Increase in EVs 2015 to 2018**



2

3 **Q. Are there models for marketing and outreach that differ from what the Company**
4 **has proposed?**

5 A. Yes. In addition to targeted customer outreach campaigns described above, another
6 approach is to address education and incentive barriers at the point of sale. Lack of
7 familiarity with electric vehicles can lead sales representatives to shy away from selling
8 EVs, or even to actively discourage purchase of EVs. . For example, Consumer Reports
9 found that “When asked how much it would cost to charge an EV, only about 19 percent
10 of salespeople gave reasonably accurate answers. Some responses were bizarre – one
11 dealer said that it would cost “ten times as much to charge at 120 volts as at 240.”⁴⁸ Even
12 more troubling, Green Car Reports wrote that “hundreds of cases have been reported of

⁴⁸ Charles Morris, “Are Auto Dealers the EV’s Worst Enemy?,” *Charged Electric Vehicles*, September 9, 2014, <https://chargedevs.com/features/are-auto-dealers-the-evs-worst-enemy/>.

1 customers walking into a Nissan or Chevy dealer to buy a LEAF or Volt, then being
2 aggressively steered toward a Sentra or Cruze.”⁴⁹ Although one might expect some
3 learning curve for dealerships in the initial years, these problems appear to be persistent,
4 even today in the most mature EV markets, as found by the market research firm Ipsos
5 RDA in its fall 2017 study.⁵⁰

6 **Q. Are you aware of any state initiatives to address this structural marketing barrier?**

7 A. Yes, several different approaches have been taken. In California, a dealership training
8 curriculum was developed and is conducted by a collaboration of organizations. In
9 Connecticut, monetary incentives are provided to dealerships in return for each purchase
10 of an electric vehicle. The Connecticut Hydrogen and Electric Automobile Purchase
11 Rebate (CHEAPR) program provides a dealer incentive for each rebated vehicle.
12 According to the evaluation report, the dealership incentive program “has significantly
13 changed dealer perceptions of selling EVs, with 74 percent of respondents saying that the
14 rebate has made them and their sales staff more open to EVs as a real alternative to
15 conventional vehicles.”⁵¹

⁴⁹ John Voelcker, “Many Car Dealers Don’t Want To Sell Electric Cars: Here’s Why,” *Green Car Reports*, February 14, 2014, https://www.greencarreports.com/news/1090281_many-car-dealers-dont-want-to-sell-electric-cars-heres-why.

⁵⁰

⁵¹ Clair Johnson et al., “Evaluating the Connecticut Dealer Incentive for Electric Vehicle Sales” (Center for Sustainable Energy, June 2017), 6, <https://energycenter.org/sites/default/files/docs/nav/research/CT-Dealer-IncentiveEvaluation-CSE-2017.pdf>.

1 **7. ELECTRIC HEAT INITIATIVE**

2 **Q. Please explain the role of electric heat in achieving Rhode Island's energy policy**
3 **goals.**

4 A. Efficient electric heat will play a critical role in meeting Rhode Island's greenhouse gas
5 emissions goals. Efficient heat pumps offer one of the few cost-effective means for
6 offsetting emissions from fossil fuels consumed in customer homes and buildings for
7 space and water heating purposes.

8 **Q. Do you have findings with respect to the proposed incentives for heating**
9 **conversions?**

10 A. Yes. In general, we support the Company's proposal to issue rebates to customers to
11 defray the up-front cost of converting from fossil fuel heating sources to air-source or
12 ground-source heat pumps. The concept of providing up-front incentives for energy-
13 saving improvements in customers' homes is a proven strategy with demonstrated
14 success in the state's energy efficiency programs.

15 **Q. Do you have any concerns regarding the electric heat initiative and similar efforts**
16 **being undertaken in the EE programs?**

17 A. Yes. It is very important that the Company's electric heat initiative be coordinated with
18 the related programs that it offers through its energy efficiency programs. Ideally, the
19 Company would offer a single program to customers so that all customers and trade allies
20 would be provided with the same marketing materials, technical, support, and financial
21 incentives. Otherwise, program implementation could be inefficient, customers and trade

1 allies could be confused or frustrated, and the Company could earn inconsistent
2 shareholder incentives.

3 **Q. Do you have any comments regarding the GSHP component?**

4 A. Yes. We recommend against cost recovery for this program at this time. The Division
5 questions the value of utility ownership of a customer’s heating equipment as proposed
6 by the Company.

7 **Q. Do you have any comments regarding the community-based program?**

8 A. Yes. We recommend against cost recovery for this program at this time. While the
9 potential for a community-based outreach program for clean heating systems exists, (e.g.,
10 a “Solarize” campaign for heat pumps), the Division questions whether administration of
11 such an initiative is the appropriate role for the Company.

12 **Q. Do you have recommendations regarding the proposed Gas and Propane Dealers
13 program?**

14 A. Engagement with oil and propane heating companies is an important component of a
15 successful heat electrification strategy. The Company’s proposed training programs,
16 however, do not appear to have been vetted with delivered fuels industry stakeholders,
17 nor do they appear to respond to the applicable barriers those workers face in entering the
18 heat pump sector. The Division remains open to a redesign of such a program to meet the
19 needs of the delivered fuels industry.

20 We propose to take the proposed \$180,000 and combine it with the \$499,000 of
21 marketing funds proposed for electric vehicles and create a single “Strategic
22 Electrification Outreach and Marketing Fund” for the Company to use to develop

1 strategic distribution channels to advance electrification through partnerships with deals,
2 distributors and other key stakeholders. This targeted approach to both sectors may create
3 far more cost-effective outreach than a mass-media approach. The Company should be
4 required to submit a Plan for PUC approval with DPUC consultation and comment prior
5 to use of the funds.

6 **Q. Do you have any additional recommendations regarding the electric heat initiative?**

7 A. Yes. As the Company increases its implementation of efficient electric heat over time, it
8 should also reduce its support through the energy efficiency programs for conversion
9 from inefficient oil heat to efficient gas heat systems. Encouraging the installation of gas
10 heating systems – even efficient ones – will lock in the use of fossil fuels longer than
11 necessary thereby making it more difficult to meet the states greenhouse gas emission
12 goals.

13 **8. ELECTRIC STORAGE INITIATIVE**

14 **Q. Have you reviewed the Company's proposed storage initiative?**

15 A. Yes, and we do not support the Company's initiative as proposed.

16 **Q. Please explain your concerns regarding the Company's proposed storage
17 investments.**

18 A. First, as presented, the Company's proposal has a benefit to cost ratio significantly less
19 than 1.0 (0.45). The Company's proposal to compensate for the low BCA by siting the
20 storage at children's educational institutions for community and educational benefit is not
21 compelling. Instead, the Company should use its distribution system planning capabilities
22 to identify locations at which energy storage would provide value to the distribution

1 system or provide meaningful reliability or resilience benefits, such as public facilities or
2 emergency operations.

3 **9. INCOME ELIGIBLE SOLAR INITIATIVE**

4 **Q. Have you reviewed the Company’s proposed income eligible solar initiative?**

5 A. Yes, and we do not support the Company’s initiative as proposed.

6 **Q. Please explain your concerns regarding the Company’s proposed income eligible
7 solar investments.**

8 A. It is not clear that the benefits of this program would outweigh the costs, even
9 considering the unquantified benefits to income eligible customers. We expect that there
10 are more effective and less costly ways to provide benefits to income eligible customers,
11 for example by increasing income-eligible customer participation in other DER
12 initiatives.

13 In addition, the proposal would site the solar development within certain income-
14 eligible neighborhoods, increasing the existing problem of industrial infrastructure being
15 concentrated in areas in which income eligible populations reside.

16 **10. ADVANCED METERING FUNCTIONALITY**

17 **a. National Grid’s Proposal**

18 **Q. Please describe the Company’s proposed AMF study.**

19 A. The Company has requested approval to perform additional design work during FY 2019
20 in order to “provide the necessary groundwork for implementation of its future AMF

1 investments” that it will submit for further review and approval by December 1, 2018.⁵²

2 The cost of this design work was very roughly estimated by the Company to be

3 \$2,000,000, and would impact the revenue requirements at issue in the instant docket.⁵³

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

5 A. Yes. In order for Rhode Island to achieve the outcomes recommended by stakeholders in

6 Docket 4600, AMF investments will be necessary. For example, AMF enables the

7 following outcomes: “outage protection, faster outage restoration, access to various

8 pricing options that can save [customers] money, access to energy efficiency and

9 renewable services tailored to [customers’] usage, and more efficient use of the

10 distribution system that creates consumer savings.”⁵⁴

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

12 A. The Company has developed preliminary cost estimates associated with full deployment

13 of advanced metering functionality in Rhode Island, and expects that the deployment will

14 result in significant benefits to customers and system savings. These benefits include

15 enhanced energy management capability, enablement of third party programs and

16 offerings, enhanced volt-var optimization, avoided O&M costs, and storm outage

17 management system improvements.⁵⁵

⁵² *Id.*, page 37

⁵³ Direct Testimony of the Power Sector Transformation Panel, January 12, 2018, page 4 and response to Attachment DIV 19-8-3 (Docket 4770).

⁵⁴ *Ibid.*, page 32.

⁵⁵ *Id.*, page 38

1 The Company's initial benefit-cost analysis shows that the investment is expected
 2 to be cost-effective under six of eight scenarios. These scenarios are shown in the table
 3 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

4
 5 **Q. Is it appropriate to conduct additional analysis prior to submitting an application**
 6 **for a full roll-out of AMF?**

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

12 Second, the technology and business models associated with AMF are evolving
 13 quickly. To fully capture the potential benefits associated with AMF, the Company
 14 should study new and emerging approaches to AMF – approaches that would reduce
 15 costs, avoid technology obsolescence, and reduce the risk of stranded costs. In other
 16 words, we believe that additional study could enable the Company to employ innovative

1 practices for AMF implementation beyond what is typically done in the industry,
2 potentially providing much greater net benefits to customers and serving as a model
3 nationally.

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

5 A. As discussed in the Rhode Island Power Sector Transformation report,⁵⁶ the Company
6 should study the potential for shared communication infrastructure and enabling access to
7 third party providers. In addition, we recommend that the Company investigate
8 procurement of AMF as a service, rather than through a capital investment.

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

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

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

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

⁵⁶ Rhode Island Power Sector Transformation report, November 8, 2017, page 42.

1 In addition, new services are emerging that disaggregate customer usage data to provide
2 services such as predictive analytics and preventative maintenance (e.g., informing
3 customers that their furnace is working harder than normal, so it may be time to replace
4 the filter), or informing customers about happenings in their home (for example, that their
5 kids are home or that their attic light is on).⁵⁷

6 **Q. Please explain what you mean by the procurement of “AMF as a service.”**

7 A. In many industries, equipment manufacturers now provide equipment-as-a-service, rather
8 than requiring customers to purchase the equipment through a large capital investment. A
9 similar concept is being applied to the smart grid through “smart-grid-as-a-service”⁵⁸ or
10 “metering-as-a-service” where a third party provider owns the equipment, fully manages
11 the project, and provides operational support to utilities through a subscription service.⁵⁹
12 This approach is already common for software, but is becoming more common for
13 hardware as well. For example, Leidos has provided this service to several municipalities
14 and cooperatives nationwide.⁶⁰ A presentation by the Company includes the following

⁵⁷ Examples of such companies currently providing these services are Powerley and Whisker Labs.

⁵⁸ 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.

⁵⁹ MeterSys, “Metering as a Service® (MaaS),” MeterSys Advanced Metering Solutions, 2018, <https://metersys.com/metering-as-a-services-maas/>.

⁶⁰ 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>.

1 comparison of utility AMI deployment strategies:⁶¹

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	\$\$\$\$+	\$\$ + \$\$	\$\$\$

2

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

4 A. The Company states that the study will be used “to undertake the next phase of design,
5 including further exploration of partnerships, stakeholder input, and other innovative
6 program elements, and to undertake a procurement exercise.”⁶² In particular, the
7 Company states that it has “commenced an effort to explore the value of a state-wide
8 communications system,” and has issued a Request for Information to identify qualified
9 suppliers to receive an end-to-end “Request for Solution” and to gather market

⁶¹ Steven Root, “Best Practices on AMI Implementation and Operations for Improving Efficiency,” November 5, 2015, http://www.publicpower.com/pdf/ecc15/Steven_Root.pdf.

⁶² *Id.*, Page 3 of 31.

1 intelligence. In addition, the Company proposes to explore additional functionalities
2 including load disaggregation and gas demand response.⁶³

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

4 A. The Company has not provided a detailed description for the study. Instead, the Company
5 developed a very general estimate of the costs at the departmental function level for its
6 New York affiliate⁶⁴ that lacked detail. From this New York estimate, the Company
7 extrapolated a study cost that would apply to a combined New York/Rhode Island study.

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

9 A. The decision of whether and how to pursue AMF should not be taken lightly. It is a very
10 large investment with potentially large benefits. For this reason, the Company should
11 explore deployment scenarios, technologies, and other options very carefully. However,
12 the Company has not provided sufficient detail to justify spending \$2 million on such a
13 study in Rhode Island, particularly when it states that such a study would be similar to
14 that undertaken by its New York affiliate.⁶⁵ Division witness Michael Ballaban addresses
15 the cost of the study in his testimony, including what should be allowed in the revenue
16 requirement.

⁶³ Response to DIV 32-19.

⁶⁴ Response to DIV 23-5

⁶⁵ Response to DIV 23-5

1 **b. Recommendations**

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

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

14 **11. BENEFIT-COST ANALYSES**

15 **a. The Role of Benefit-Cost Analyses**

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

17 A. Benefit-cost analyses are a critical element in designing PIMs, because they can help
18 shed light on the potential net benefits of PIM activities, and thereby inform decisions
19 regarding the magnitude of PIM incentives. Ideally, PIM incentives should be set at a
20 level that will result in net benefits to customers.

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

3 A. The role of cost-effectiveness (and thus BCAs) was recently addressed in Docket 4600.
4 In April 2017, the Docket 4600 stakeholder working group submitted a report to the
5 Commission providing recommendations for a new cost-effectiveness test, among other
6 things.⁶⁶ The proposed Rhode Island Benefit-Cost Framework built off the cost-
7 effectiveness test that has been used historically for energy efficiency resources, and
8 included a broader range of costs and benefits to better reflect power sector
9 transformation and state energy policy goals.

10 In October 2017, the Commission issued a Guidance Document that provided
11 direction on how to address the issues raised in Docket 4600, and accepted the proposed
12 RI Benefit-Cost Framework as the appropriate cost-effectiveness methodology.⁶⁷

13 **Q. What does the Commission’s Guidance Document say about the role of BCAs?**

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

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

⁶⁶ Docket 4600 Stakeholder Working Group, Report to the Rhode Island Public Utilities Commission, April 5, 2017.

⁶⁷ Rhode Island Public Utilities Commission, Docket 4600, *Guidance on Goals, Principles, and Values for Matters Involving the Narragansett Electric Company*, October 27, 2017.

1 in its cost of service for the primary purpose of complying with State policy or to
2 expand a current program.⁶⁸

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

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

7 Where the costs and benefits can be quantified, the proponent should provide
8 such information and the basis for the conclusion reached. Where quantification
9 is not possible or not practical, the proponent should so explain. Regardless of
10 whether the quantification can be fully completed, a qualitative analysis should
11 be included.⁶⁹

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

14 A. No. The Guidance Document states that:

15 the Benefit-Cost Framework will not be the exclusive measure of whether a
16 specific proposal should be approved. For example, there may be outside factors
17 that need to be considered by the PUC regardless of whether a specific proposal
18 is determined to be cost-effective or not. This may include statutory mandates or
19 other qualitative considerations.⁷⁰

⁶⁸ Guidance Document, p. 6.

⁶⁹ Guidance Document, p. 6.

⁷⁰ Guidance Document, p. 7.

1 **b. National Grid's Benefit-Cost Analyses**

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

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

8 **Q. Please describe the best-fit/least-cost methodology used by the Company for DER-**
9 **enabling⁷¹ investments.**

10 A. The Company refers to a recent US Department of Energy "Decision Guide" (DOE
11 Report) as the source of that methodology. That report presents many different
12 considerations for the best way to implement advanced distribution system technologies,
13 including DERs.⁷² With regard to cost-effectiveness considerations, the DOE Report
14 describes advanced distribution system technologies as belonging to four categories:
15 (a) traditional utility infrastructure investments; (b) DER-enabling investments; (c) DER-
16 integration investments; and (d) self-support or direct-charge investments (i.e., those paid
17 for by customers or third-parties). The DOE Report recommends that traditional and
18 DER-enabling investments be subject to a best-fit/least-cost analysis or a traditional

⁷¹ We do not like 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.

⁷² The US Department of Energy, Modern Distribution Guide, Volume III, June 2017, Section 3.4.1.

1 utility benefit-cost analysis, and that DER-integration investments be subject to a societal
2 benefit-cost analysis.⁷³

3 In this Docket, the Company notes that it used the best-fit/least cost method “to
4 evaluate proposed grid-side investments to enable DER using a conceptual cost estimate
5 and an expectation that it will utilize a competitive procurement process as part of the
6 deployment.”⁷⁴

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

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

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

16 We note that the DOE Report is clear that it may be appropriate to apply benefit-
17 cost analyses to DER-enabling projects. It states that utilities could use best-fit/least-cost
18 methodologies or traditional utility cost-benefit analyses.⁷⁵ National Grid has chosen not
19 to use a traditional utility BCA. Further, there is nothing in the DOE Report to suggest
20 that the Company cannot or should not use a different type of BCA, such as the RI

⁷³ The US Department of Energy, Modern Distribution Guide, Volume III, June 2017, Section 3.4.1.

⁷⁴ PST Panel Direct Testimony, p. 25, lines 14-17.

⁷⁵ DOE Report, p. 39 and p. 40.

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

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

5 A. Yes. The DER-enabling projects that the Company proposes in this docket include a total
6 of \$17.3 million over the three-year period from FY2018 – FY2020.⁷⁶ This is
7 significantly larger than any other PST initiative in this docket (with the exception of the
8 AMF proposal that the Company is not asking for approval of in this docket) and thus
9 warrants more justification than the narrative that National Grid has provided.

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

13 A. Yes. The Company is essentially asking the Commission for pre-approval of its PST
14 investments.⁷⁷ As a general matter, any request for pre-approval of a project should be
15 supported with a comprehensive justification for the project, including a demonstration
16 that the project is cost-effective and will result in net benefits to customers. In the
17 absence of such a justification, the Commission should not pre-approve a project. The
18 Company has not provided such a justification for the DER-enabling projects in this
19 docket.

⁷⁶ DPUC 19-8-3

⁷⁷ PST Panel Direct Testimony, p. 96, lines 1-4. Schedule PST- 1, Chapter 10, page 1.

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

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

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

16 In addition, the Company's proposal means that traditional projects, DER-
17 enabling projects, DER-integration projects are subject to different standards of review.
18 Traditional projects would be subject to the standard of review applied in the existing rate
19 case and ISR processes, while DER-enabling projects are subject to a best-fit/least cost
20 standard, and DER-integration projects are subject to a standard based on the RI Benefit-
21 Cost Framework. This could result in some projects being inappropriately accepted or
22 rejected simply because they are subject to inconsistent standards. This would clearly be

1 inconsistent with the Commission's directives in Docket 4600 and state energy policy
2 goals in general.

3 National Grid should be seeking ways to better integrate the planning of all types
4 of resources, including EE, SRP, ISR, DER-enabling, and DER-integrating resources.
5 The Company's proposal to treat DER-enabling and DER-integrating resources different
6 goes directly against this key goal.

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

9 A. The Company's cost-effectiveness methodology was designed to reflect the RI Benefit-
10 Cost Framework approved by the Commission in its Guidance Document. Some of the
11 costs and benefits are not yet sufficiently developed to be used in a quantitative fashion,
12 so the Company simply addressed them qualitatively. The Company also vetted some of
13 the inputs and value drivers with comparable exercises that it has undertaking for its
14 Massachusetts and New York affiliates. The Company used assumptions and
15 methodologies that are used to evaluate the EE programs, including all applicable
16 avoided costs from the 2015 New England Avoided Energy Supply Costs report.⁷⁸

17 **c. Critique of National Grid's Benefit-Cost Analysis**

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

19 A. For those projects where it applied a BCA, the Company used the RI Benefit-Cost
20 Framework approved by the Commission in the 4600 Guidance Document. This is

⁷⁸ PST Panel Direct Testimony, pp.25-26.

1 clearly the appropriate framework to use in this context. In addition, the Company
2 appropriately included a discussion of the qualitative benefits for each project, as
3 required in the 4600 Guidance Document.

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

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

12 A. In all of its BCAs, National Grid assumes that there will be no avoided distribution
13 system costs. This is presumably because the Company did not have estimates of avoided
14 distribution costs that it deemed sufficiently robust.⁷⁹ In addition, avoided distribution
15 costs can vary significantly by geographic location, creating another challenge in
16 identifying reasonable assumptions for a BCA.

17 We are sympathetic to the limitations of current estimates of avoided distribution
18 costs. However, assuming that DERs will provide no value in the form of avoided
19 distribution costs is overly conservative. Distribution system benefits can be significant,
20 particularly for some types of DERs, such as demand response or storage, which could be

⁷⁹ [Did the Company explain this in any of its discovery responses? If so, cite.]

1 specifically designed to defer or avoid distribution projects. This assumption by National
2 Grid will result in understating the benefits of the projects analyzed in the BCAs.

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

5 A. It is not clear what source National Grid used to determine avoided FCM capacity costs.
6 In some instances, the Company refers to the 2015 AESC Report as the source of avoided
7 cost assumptions for its BCAs.⁸⁰ In other instances, the Company refers to the AESC
8 2015 Update,⁸¹ which was performed to reflect significant changes that had occurred in
9 the New England wholesale electricity markets after the original report was conducted.⁸²
10 The distinction is very important because the avoided costs in the AESC 2015 Update are
11 significantly lower than in the 2015 AESC Report.

12 Our review of the Company's assumptions suggests that the values used were
13 those from the 2015 AESC Report. The Company's avoided FCM assumptions⁸³ are
14 considerably higher than those included in the AESC 2015 Update.⁸⁴ If it is true that
15 National Grid used the original 2015 AESC values, then its BCAs will overstate the
16 benefits of the projects analyzed in the BCAs.

⁸⁰ Schedule PST – 1, Chapter 2, p. 5, footnote 5.

⁸¹ Docket 4770 Response to Division 25-6, Attachment DIV 25-6, p. 1.

⁸² Tabors, Caramanis, Rudkevich, *AESC 2015 Update Results and Assumptions*, memo to the AESC Update Client Group, December 2016.

⁸³ As reported in Docket 4770 Response to Division 25-6, Attachment DIV 25-6, p. 1.

⁸⁴ As reported in the AESC 2015 Update, Appendix B, p 1 of 2.

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

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

8 In addition, the Commission’s Guidance Document in 4600 emphasizes the
9 importance of long-term objectives and policy goals. The Guidance Document begins
10 with a list of stated electric industry goals that were approved by the Commission. The
11 first goal is to provide “reliable, safe, clean, and affordable energy to Rhode Island
12 customers over the *long term*” (emphasis added).⁸⁵ The next two goals refer to addressing
13 climate change and other environmental challenges, and promoting jobs and economic
14 development; which also suggest a preference for long-term objectives and policy goals.
15 As noted below, a societal discount rate places greater emphasis on long-term impacts,
16 relative to a discount rate based on a utility WACC.

17 Further, using a utility WACC for a discount rate is not consistent with the goals
18 of the Company’s benefit-cost analysis in general.⁸⁶ A utility WACC represents the time
19 preference of utility investors, primarily based on the cost of capital and the risks to those
20 investors. A utility WACC would be appropriate for the purposes of maximizing value to

⁸⁵ Rhode Island Public Utilities Commission, Docket 4600 Guidance Document, page 3.

⁸⁶ For additional discussion of this point, see: National Efficiency Screening Project, *the National Standard Practice Manual*, Chapter 9, May 2017.

1 utility investors, but this is not the purpose of the BCA. The purpose of the BCA is to
2 identify the optimal mix of resources that will lead to “reliable, safe, clean, and
3 affordable energy to Rhode Island customers over the long-term.”⁸⁷ A societal discount
4 rate is much more consistent with this purpose.

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

10 **Q. How does a societal discount rate compare with a utility’s WACC?**

11 A. A societal discount rate is typically much lower than a utility’s WACC. There is a range
12 of views on what a societal discount rate should be, and the specific value of a societal
13 discount rate should depend upon the impacts and the analysis it is applied to. Some
14 analysts argue that a societal discount rate for valuing environmental impacts should be
15 negative (in real terms). Others use societal discount rates on the order of one, two, or
16 three percent (in real terms).⁸⁸ This entire range of societal discount rates is lower than
17 the Company’s WACC which is 7.5 percent in nominal terms, and 4.8 percent in real
18 terms.

⁸⁷ Rhode Island Public Utilities Commission, Docket 4600 Guidance Document, page 3.

⁸⁸ National Standard Practice Manual, page 75.

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

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

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

11 A. As one example, we used different discount rates for the Company's BCA for advanced
12 metering infrastructure, in the case where the AMF costs are shared with New York, and
13 in the Opt-Out Low Participation Scenario. Using the discount rate equal to the
14 Company's WACC (4.8 percent in real terms) results in a benefit-cost ratio is 1.19; using
15 a societal discount rate of two percent (in real terms), results in a benefit-cost ratio of
16 1.34; and using the current energy efficiency BCA discount rate of roughly 0.3 percent
17 (in real terms) results in a benefit-cost ratio of 1.44.

18 **d. Recommendations**

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

21 A. We recommend that the Commission reject the Company's proposal to evaluate any PST
22 related projects, or any projects for which it is seeking pre-approval, with the best-

1 fit/least cost methodology. This methodology is inconsistent with the Docket 4600
2 Guidance Document; is inconsistent with the overall goal of integrating the planning,
3 review, and approval of all types of distribution system investment; and does not provide
4 sufficient justification for the Commission to pre-approve projects.

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

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

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

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

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

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

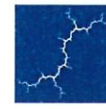
6 **Q. You have identified several significant problems with the Company's BCAs, two of**
7 **which understate benefits, and one of which overstates benefits. Are you concerned**
8 **that these problems will lead to the Commission approving uneconomic outcomes in**
9 **this docket?**

10 A. According to National Grid's proposal, all the PST initiatives that National Grid is
11 proposing in this docket will be subject to further review by the Commission prior to
12 them being undertaken by the Company. These PST initiatives will be included in the
13 annual PST Plans that will be filed with the Commission. The first Plan will be filed by
14 December 1, 2018, to investigate the potential PST initiatives for FY 2020.⁸⁹ At that time,
15 the Company should file updated BCAs for each PST initiative that it seeks approval for,
16 with improved methodologies and inputs using the Commission directives from this
17 docket. Consequently, the BCA results presented in this docket will not be the final BCA
18 results used to make decisions on future PST initiatives.

19 **Q. Does this conclude your direct testimony?**

20 A. Yes, it does.

⁸⁹ PST Panel Direct Testimony, p. 5, lines 4-7.

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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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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 Regroupement 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.

Woolf, 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.

Woolf, 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.

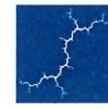
Woolf, T. 2000. "Comments of the Citizens Action Coalition of Indiana." Presentation at Workshop on Alternatives to Traditional Generation Resources, June 2000.

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

Fisher, J., M. Whited, T. Woolf, D. Goldberg. 2018. *Utility Investments for Market Transformation: How Utilities Can Help Achieve Energy Policy Goals*. Prepared by Synapse Energy Economics for Energy Foundation.

Whited, M., T. Woolf. 2018. *Electricity Prices in the Tennessee Valley: Are customers being treated fairly?* Prepared by Synapse Energy Economics for the Southern Alliance for Clean Energy.

Woolf, T., A. Hopkins, M. Whited, K. Takahashi, A. Napoleon. 2018. *Review of New Brunswick Power's 2018/2019 Rate Case Application*. In the Matter of the New Brunswick Power Corporation and Section 103(1) of the Electricity Act Matter No. 375. Prepared by Synapse Energy Economics for the New Brunswick Energy and Utilities Board Staff.

Whited, M., T. Vitolo. 2017. Reply comments in District of Columbia Public Service Commission Formal Case No. 1130: *Reply Comments of the Office of the People's Counsel for the District of Columbia Regarding Pepco's Comments on the Office of the People's Counsel's Value of Solar Study*. Prepared by Synapse Energy Economics. July 24, 2017.

Whited, M., A. Horowitz, T. Vitolo, W. Ong, T. Woolf. 2017. *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting*. Synapse Energy Economics for the Office of the People's Counsel for the District of Columbia.

Whited, M., E. Malone, T. Vitolo. 2016. *Rate Impacts on Customers of Maryland's Electric Cooperatives: Impacts on SMECO and Choptank Customers*. Synapse Energy Economics for Maryland Public Service Commission.

Woolf, T., M. Whited, P. Knight, T. Vitolo, K. Takahashi. 2016. *Show Me the Numbers: A Framework for Balanced Distributed Solar Policies*. Synapse Energy Economics for Consumers Union.

Whited, M., T. Woolf, J. Daniel. 2016. *Caught in a Fix: The Problem with Fixed Charges for Electricity*. Synapse Energy Economics for Consumers Union.

Lowry, M. N., T. Woolf, M. Whited, M. Makos. 2016. *Performance-Based Regulation in a High Distributed Energy Resources Future*. Pacific Economics Group Research and Synapse Energy Economics for Lawrence Berkley National Laboratory.

Woolf, T., M. Whited, A. Napoleon. 2015-2016. *Comments and Reply Comments in the New York Public Service Commission Case 14-M-0101: Reforming the Energy Vision*. Comments related to Staff's (a) a benefit-costs analysis framework white paper, (b) ratemaking and utility business models white paper, and (c) Distributed System Implementation Plan guide. Prepared by Synapse Energy Economics on behalf of Natural Resources Defense Council and Pace Energy and Climate Center.

Luckow, P., B. Fagan, S. Fields, M. Whited. 2015. *Technical and Institutional Barriers to the Expansion of Wind and Solar Energy*. Synapse Energy Economics for Citizens' Climate Lobby.

Wilson, R., M. Whited, S. Jackson, B. Biewald, E. A. Stanton. 2015. *Best Practices in Planning for Clean Power Plan Compliance*. Synapse Energy Economics for the National Association of State Utility Consumer Advocates.

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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.

Virginia State Corporation Commission (Case No. PUR-2017-00044): Direct testimony of Melissa Whited regarding Rappahannock Electric Cooperative's proposed increases to fixed charges for residential customers and small business customers. On behalf of Sierra Club. September 19, 2017.

California Public Utilities Commission (Application 17-01-020, 17-01-021, and 17-01-022): Joint opening testimony with Max Baumhefner and Katherine Stainken on fast charging infrastructure and rates; joint opening testimony with Max Baumhefner and Joel Espino on medium and heavy-duty and fleet charging infrastructure and commercial EV rates; joint opening testimony with Max Baumhefner and Chris King on residential charging infrastructure and rates. Rebuttal testimony on public fast charging rate design, commercial EV rate design, and residential EV rate design. On behalf of Natural Resources Defense Council, the Greenlining Institute, Plug In America, the Coalition of California Utility Employees, Sierra Club, and the Environmental Defense Fund. July 25, August 1, August 7, and September 5, 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 testimony of Melissa Whited regarding PacifiCorp's proposed rates for customers with distributed generation. On behalf of Utah Clean Energy. June 8, 2017.

Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449): Cross-rebuttal testimony evaluating Southwestern Electric Power Company's proposed revisions to its Distributed Renewable Generation tariff. On behalf of Sierra Club and Dr. Lawrence Brough. May 19, 2017.

Massachusetts Department of Public Utilities (Docket No. 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.

Public Utilities Commission of Hawaii (Docket No. 2015-0170): Direct testimony regarding Hawaiian Electric Light Company's proposed performance incentive mechanisms. On behalf of the Division of Consumer Advocacy. April 28, 2017.

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Federal Energy Regulatory Commission (Docket No. EC13-93-000): Affidavit regarding potential market power resulting from the acquisition of Ameren generation by Dynegy. On behalf of Sierra Club. August 16, 2013.

Wisconsin Senate Committee on Clean Energy: Joint testimony with M. Grabow regarding the importance of clean transportation to Wisconsin's public health and economy. February 2010.

TESTIMONY ASSISTANCE

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

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.

Wisconsin Public Service Commission (Docket No. 05-UR-107): Direct and surrebuttal testimony of Rick Hornby regarding Wisconsin Electric Power Company rate case. On behalf of The Alliance for Solar Choice. August 28, 2014 and September 22, 2014.

Maine Public Utilities Commission (Docket No. 2013-00519): Direct testimony of Richard Hornby and Martin R. Cohen on GridSolar's smart grid coordinator petition. On behalf of the Maine Office of the Public Advocate. August 28, 2014.

Maine Public Utilities Commission (Docket No. 2013-00168): Direct and surrebuttal testimony of Tim Woolf regarding Central Maine Power's request for an alternative rate plan. December 12, 2013 and March 21, 2014.

Massachusetts Department of Public Utilities (Docket No. 14-04): Comments of Massachusetts Department of Energy Resources on investigation into time varying rates. On behalf of the Massachusetts Department of Energy Resources. March 10, 2014.

State of Nevada, Public Utilities Commission of Nevada (Docket No. 13-07021): Direct testimony of Frank Ackerman regarding the proposed merger of NV Energy, Inc. and MidAmerican Energy Holdings Company. On behalf of the Sierra Club. October 24, 2013.

PRESENTATIONS

Whited, M. 2016. "Energy Policy for the Future: Trends and Overview." Presentation to the National Conference of State Legislators' Capitol Forum, Washington, DC, December 8.

Whited, M. 2016. "Ratemaking for the Future: Trends and Considerations." Presentation to the Midwest Governors' Association, St. Paul, MN, July 14.

Whited, M. 2016. "Performance Based Regulation." Presentation to the NARUC Rate Design Subcommittee. September 12.

Whited, M. 2016. "Demand Charges: Impacts and Alternatives (A Skeptic's View)." EUCI 2nd Annual Residential Demand Charges Summit, Phoenix, AZ, June 7.

Whited, M. 2016. "Performance Incentive Mechanisms." Presentation to the National Governors Association, Wisconsin Workshop, Madison WI, March 29.

Whited, M., T. Woolf. 2016. "Caught in a Fix: The Problem with Fixed Charges for Electricity." Webinar presentation sponsored by Consumers Union, February.

Whited, M. 2015. "Performance Incentive Mechanisms." Presentation to the National Governors Association, Learning Lab on New Utility Business Models & the Electricity Market Structures of the Future, Boston, MA, July 28.

Whited, M. 2015. "Rate Design: Options for Addressing NEM Impacts." Presentation to the Utah Net Energy Metering Workgroup, Workshop 4, Salt Lake City, UT, July 8.

Whited, M. 2015. "Performance Incentive Mechanisms." Presentation to the e21 Initiative, St. Paul, MN, May 29.

Whited, M., F. Ackerman. 2013. "Water Constraints on Energy Production: Altering our Current Collision Course." Webinar presentation sponsored by Civil Society Institute, September 12.

Whited, M., G. Brown, K. Charipar. 2011. "Electricity Demand Response Programs and Potential in Wisconsin." Presentation to the Wisconsin Public Service Commission, April.

Whited, M. 2010. "Economic Impact of Irrigation Water Transfers in Uvalde County, Texas." Presentation at the Mid-Continent Regional Science Association's 41st Annual Conference/IMPLAN National User's 8th Biennial Conference in St. Louis, MO, June

Whited, M., M. Grabow, M. Hahn. 2009. "Valuing Bicycling's Economic and Health Impacts in Wisconsin." Presentation before the Governor's Coordinating Council on Bicycling, December.

Whited, M., D. Sheard. 2009. "Water Conservation Initiatives in Wisconsin." Presentation before the Waukesha County Water Conservation Coalition Municipal Water Conservation Subgroup, July.

Resume dated March 2018

DIVISION EXHIBIT 3
 Electric Transport Initiative -- Cost Summary: Proposed, Adjustments and Net

	COMPANY PROPOSED				DIVISION ADJUSTMENTS				NET PROGRAM FUNDING			
	Year 1	Year 2	Year 3	Total	Year 1	Year 2	Year 3	Total	Year 1	Year 2	Year 3	Total
Charging Rebate Pilot												
O&M	\$ 178,745	\$ 244,420	\$ 332,567	\$ 755,731	\$ (90,000)	\$ (90,000)	\$ (90,000)	\$ (270,000)	\$ 88,745	\$ 154,420	\$ 242,567	\$ 485,732
Capital	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Charging Station Demonstration												
O&M	\$ 388,843	\$ 540,362	\$ 1,006,320	\$ 1,937,525	\$ (88,000)	\$ (88,000)	\$ (106,000)	\$ (282,000)	\$ 300,843	\$ 452,362	\$ 902,320	\$ 1,655,525
Capital	\$ 988,470	\$ 1,828,501	\$ 4,326,511	\$ 7,143,482	\$ (122,633)	\$ (306,583)	\$ (797,116)	\$ (1,226,332)	\$ 865,837	\$ 1,521,918	\$ 3,529,395	\$ 5,917,150
Discount Pilot for Direct Current Fast Charging												
O&M	\$ 103,622	\$ 170,650	\$ 264,488	\$ 538,760	\$ -	\$ -	\$ -	\$ -	\$ 103,622	\$ 170,650	\$ 264,488	\$ 538,760
Capital	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Outreach and Education												
O&M	\$ 113,970	\$ 164,959	\$ 220,468	\$ 499,397	\$ -	\$ -	\$ -	\$ -	\$ 113,970	\$ 164,959	\$ 220,468	\$ 499,397
Capital	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Company Fleet expansion												
O&M	\$ 64,000	\$ 128,000	\$ 192,000	\$ 384,000	\$ (64,000)	\$ (128,000)	\$ (192,000)	\$ (384,000)	\$ -	\$ -	\$ -	\$ -
Capital	\$ 200,000	\$ -	\$ -	\$ 200,000	\$ (200,000)	\$ -	\$ -	\$ (200,000)	\$ -	\$ -	\$ -	\$ -
Evaluation												
O&M	\$ 30,000	\$ 30,000	\$ 30,000	\$ 90,000	\$ -	\$ -	\$ -	\$ -	\$ 30,000	\$ 30,000	\$ 30,000	\$ 90,000
Capital	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
TOTAL COST												
TOTAL O&M	\$ 879,179	\$ 1,278,391	\$ 2,047,843	\$ 4,205,413	\$ (242,000)	\$ (306,583)	\$ (388,000)	\$ (956,000)	\$ 657,180	\$ 972,391	\$ 1,655,843	\$ 3,269,414
TOTAL CAPITAL	\$ 1,188,470	\$ 1,828,501	\$ 4,326,511	\$ 7,343,482	\$ (322,633)	\$ (306,583)	\$ (797,116)	\$ (1,426,332)	\$ 865,837	\$ 1,521,918	\$ 3,529,395	\$ 5,917,150

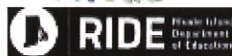
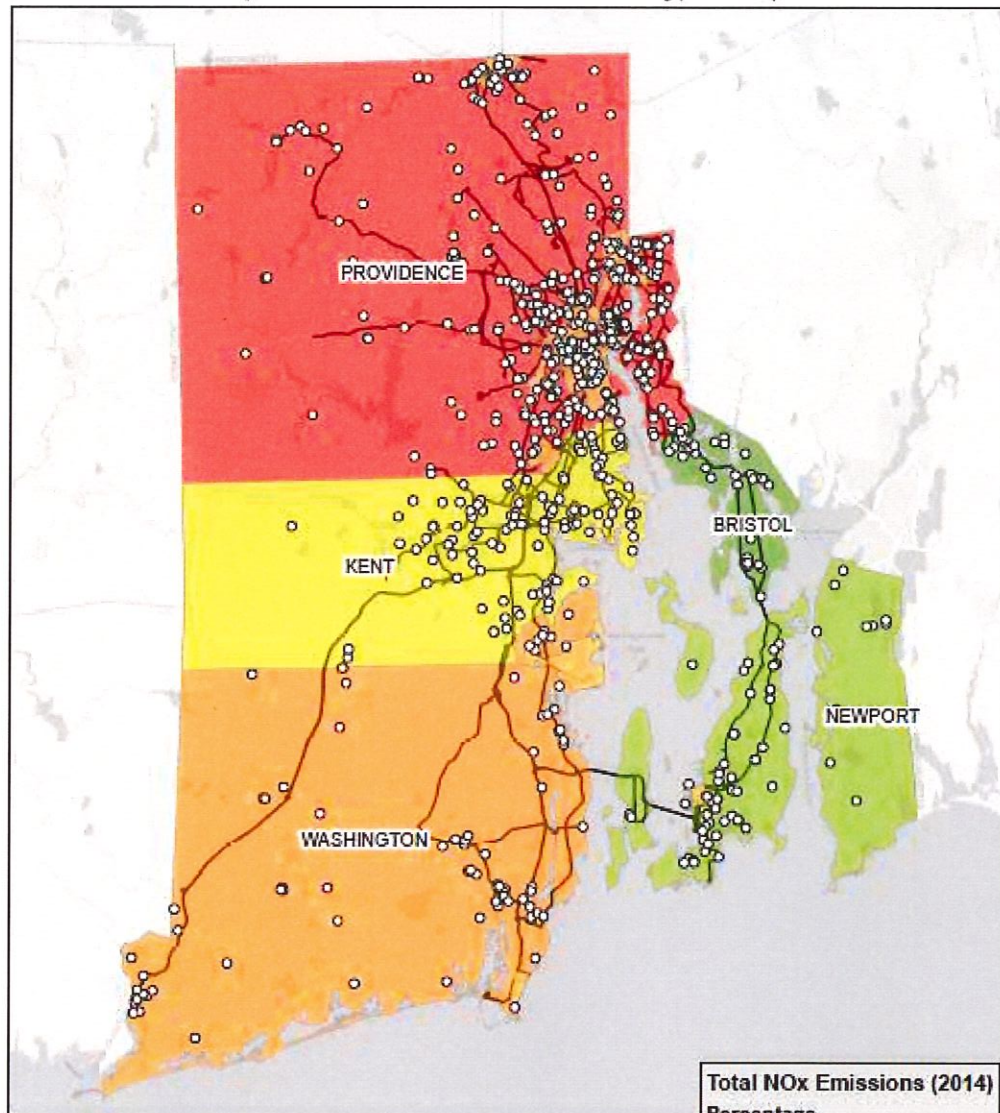
DIVISION EXHIBIT 4
 Electric Heat Initiative -- Cost Summary: Proposed, Adjustments and Net

	COMPANY PROPOSED			DIVISION ADJUSTMENTS			NET PROGRAM FUNDING			
	Year 1	Year 2	Year 3	Year 1	Year 2	Year 3	Year 1	Year 2	Year 3	Total
GSHP										
O&M	\$ -	\$ 95,000	\$ -	\$ (95,000)	\$ -	\$ -	\$ 252,140	\$ 280,890	\$ 309,640	\$ 842,670
Capital	\$ -	\$ 500,000	\$ -	\$ (500,000)	\$ -	\$ -	\$ 252,140	\$ 280,890	\$ 309,640	\$ 842,670
Equipment Incentives										
O&M	\$ 252,140	\$ 280,890	\$ 309,640	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Capital	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Community Based Outreach										
O&M	\$ 95,500	\$ 95,500	\$ 95,500	\$ (95,500)	\$ (95,500)	\$ (95,500)	\$ -	\$ -	\$ -	\$ -
Capital	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Oil Dealer Training and Support										
O&M	\$ 61,000	\$ 61,000	\$ 61,000	\$ -	\$ -	\$ -	\$ 61,000	\$ 61,000	\$ 61,000	\$ 183,000
Capital	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
TOTAL COST										
TOTAL O&M	\$ 408,640	\$ 437,390	\$ 466,140	\$ (95,500)	\$ (690,500)	\$ (95,500)	\$ (95,500)	\$ (61,000)	\$ (61,000)	\$ 1,025,670
TOTAL CAPITAL	\$ -	\$ 500,000	\$ -	\$ (95,500)	\$ (500,000)	\$ (500,000)	\$ -	\$ -	\$ -	\$ -
TOTAL										
	\$ 1,907,170	\$ 1,907,170	\$ 1,907,170	\$ (95,500)	\$ (690,500)	\$ (95,500)	\$ (95,500)	\$ (61,000)	\$ (61,000)	\$ 1,025,670
	\$ 1,407,170	\$ 1,407,170	\$ 1,407,170	\$ (95,500)	\$ (500,000)	\$ (500,000)	\$ -	\$ -	\$ -	\$ 1,025,670
	\$ 500,000	\$ 500,000	\$ 500,000	\$ (500,000)	\$ (500,000)	\$ (500,000)	\$ -	\$ -	\$ -	\$ -

Explanation
 Eliminate program
 Eliminate program
 Include in Strategic Electrification Marketing Fund

DIVISION EXHIBIT 5: RIPTA Bus Routes Relative to Environmental Justice Areas, RI Schools, and Total NOx Emissions Percentages by County

Mapping RIPTA Bus Routes Relative to Environmental Justice Areas, RI Schools, and Total NOx Emissions Percentages by County (National Emissions Inventory, 2014)



0 4 8 16 Miles

Draft Map Produced for RIDEM Internal Use
Office of Customer and Technical Assistance
Date: 02/27/2018

Data Sources: RIDEM, RIGIS, RIDE

Total NOx Emissions (2014)

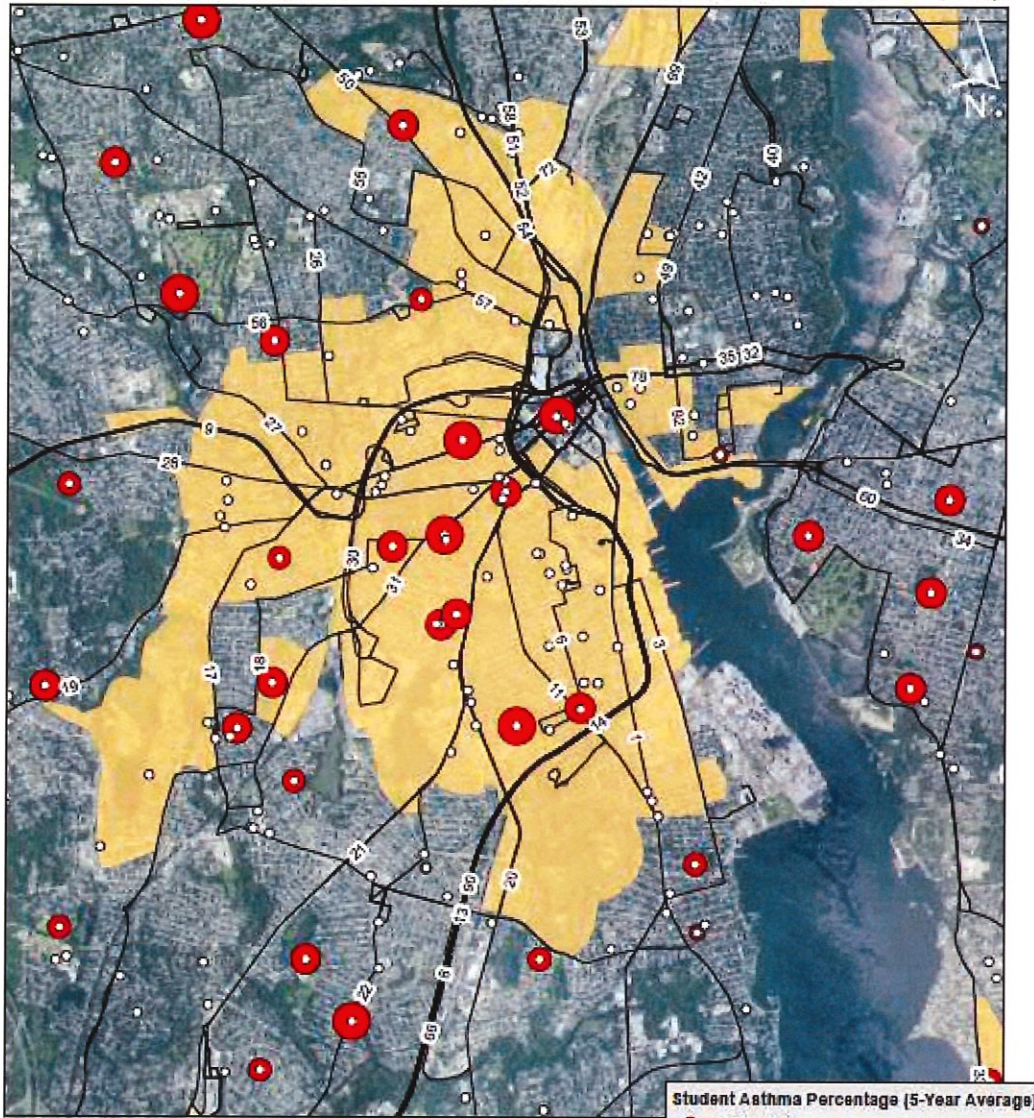
Percentage

- 2.74
- 10.61
- 15.96
- 26.71
- 43.96

Refer to Legend Key for additional map symbols

DIVISION EXHIBIT 6 Providence, RI - RIPTA Bus Routes Relative to RI Schools, Student Asthma Percentages, and Environmental Justice Areas (Five-Year Average Student Asthma Percentage)

Mapping RIPTA Bus Routes Relative to RI Schools, Student Asthma Percentages, and Environmental Justice Areas (Five-Year Average Student Asthma Percentage, Providence, RI)



Student Asthma Percentage (5-Year Average)

- 14.85 - 17.36
- 17.36 - 20.11
- 20.11 - 22.65
- 22.65 - 25.28
- 25.28 - 29.02

Refer to Legend Key for additional map symbology.

DEM
RISDOL ISLAND

RIGIS

RIDE
RISDOL ISLAND
Department of Education

0 0.5 1 2 Miles

Draft Map Produced for RIDE Internal Use
Office of Customer and Technical Assistance
Date: 02/27/2018
Data Sources: RIDE, RIGIS, RIDE