COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, for Approval of its Grid Modernization Plan	)	D.P.U. 15-120

INITIAL BRIEF OF THE MASSACHUSETTS ATTORNEY GENERAL

MAURA HEALEY
ATTORNEY GENERAL

Donald W. Boecke
Elizabeth Mahony
Joseph F. Dorfler

Assistant Attorneys General
Office of Ratepayer Advocacy
One Ashburton Place, 18th Floor
Boston, Massachusetts 02108
617-727-2200

Dated: July 14, 2017

TABLE OF CONTENTS

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, for Approval of its Grid Modernization Plan	)	D.P.U. 15-120

INITIAL BRIEF OF THE
ATTORNEY GENERAL

I. INTRODUCTION

On August 19, 2015, Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid ("National Grid" or the "Company") filed with the Department of Public Utilities ("Department") National Grid's Grid Modernization Plan ("GMP" or "Plan") pursuant to *Modernization of the Electric Grid*, D.P.U. 12-76-B (2014); D.P.U, 12-76-C (2014). The Plan consists of National Grid's ten-year strategic investment plan of proposed capital additions and Operations and Maintenance ("O&M") expense outlays intended to bring about measureable progress on the Department's objectives for grid modernization: (1) to reduce the effects of service outages; (2) optimize demand, including reducing system and customer costs; (3) integrate distributed energy resources ("DER"); and (4) improve workforce and asset management. *Modernization of the Electric Grid*, D.P.U. 12-76-B, p. 9. The Company's GMP addresses both "grid-facing" and "customer-facing" investment initiatives[1] and proposes specific incremental

[1] The Department refers to "grid-facing" modernization investments as technologies that automate grid operations and allow distribution companies to monitor and control grid conditions in near real time. "Customer-facing" capital initiatives, by contrast, are technologies primarily associated with customer metering and related investments, such as two-way communications systems, internet-based information portals, wireless applications, direct load control technologies and smart appliances and electronics. *See Modernization of the Electric Grid*, D.P.U. 12-76-A at 2, footnote 4 (2013).

capital investment expenditures for the first five years of the Plan purportedly qualifying for targeted, expedited tariff cost recovery through a proposed short-term investment plan, or "STIP."

The Plan lays out National Grid's ten-year overall spending plan for grid modernization under four, alternative plan deployment scenarios: (1) the "Balanced Plan;" (2) an "AMI-Focused" plan; (3) a "Grid-Focused" option; and (4) the [AMI] "Opt-In" scenario (*see* Grid Modernization Plan (Updated) June 14, 2016 (hereinafter "GMP Updated"), p.9). Each of the four scenarios offers alternative investment combinations among "grid-facing" capital additions and "customer-facing" capital spending – primarily advanced metering infrastructure ("AMI") to support advanced metering functionality ("AMF"). Ten-year proposed investment budgets for the scenarios run from $1,275 million for the "Balanced Plan" to $524 million for the "Opt-in" scenario. Exh. GMP Updated at Table 1, p. 11.

All four of the scenarios the Company proposes contain varying levels of investment spending for AMI and for advanced distribution management systems ("ADMS"). The Company proposes 100 percent deployment of AMI within five years of the initiation of the GMP in both the Balanced Plan and the AMI-Focused plan. Exh. GMP Updated at Table 1, p. 11. The Grid-Focused scenario scales back the proposed spending and deployment commitment for AMI (targeting AMI deployment to 30 percent of the customer base within 10 years), while the "Opt-In" proposal includes AMI delivered principally over public cellular networks and only for customers voluntarily electing AMI meters and the proposed optional time varying rates ("TVR"). *Id.*

II. SUMMARY

As the Commonwealth's ratepayer advocate, the Office of the Attorney General ("AGO") strongly supports the Department's effort to modernize the electric distribution grid. A modern grid will benefit customers by enhancing the reliability and resiliency of electric service, enabling broad integration of distributed energy resources, mitigating price increases and volatility, empowering customers to adopt new and cleaner technologies, and allowing customers to better manage their use of electricity. D.P.U. 12-76-A, p. 3.

To achieve these benefits will require substantial investments—investments in a more reliable, cleaner, customer-focused energy future. As with any large investments, the Department seeks to ensure that the Company's proposed grid modernization investments will yield the desired benefits; the Department therefore required the Company to submit a business case analysis ("BCA") to demonstrate that the anticipated benefits of the Company's proposed capital investments justify the costs. D.P.U. 12-76-C.

In its GMP, the Company proposes various "grid facing" investments. The Company's BCA supports many of these investments and many of them are critical to grid modernization. Thus, as discussed further below, the AGO recommends that the Department pre-authorize certain of the Company's proposed grid-facing investments, consistent with the recommendations set forth by Mr. Booth.

With respect to "customer side" investments, the Department recognized the important role that AMF plays in modernizing the grid, finding that AMF is a "basic technology platform for grid modernization." D.P.U. 12-76-B, p. 13; *see also* D.P.U. 12-76-A, p. 12. There is no doubt that AMF has the potential to deliver benefits to customers as well as other stakeholders including electric distribution companies, competitive suppliers, demand response providers, distributed generation owners and third party vendors, under certain conditions. However, the Company's GMP, as currently presented and under the current regulatory structure, does not identify sufficient ratepayer benefits to justify the costs of AMF at this time. Therefore, the Department should not pre-authorize these investments nor allow the Company to utilize the special rate recovery mechanism outlined in D.P.U. 12-76-B for AMF deployment at this time.

The Company's GMP, along with its BCA, however, offers the Department and stakeholders key insights into the benefits that currently are available to customers and the actions that the Department and other stakeholders can take to unleash the full panoply of ratepayer benefits of AMF, at the lowest possible cost. D.P.U. 12-76-C, p. 3. The AGO recommends that the Department use the Company's thoughtful GMP as a foundation to make further progress on grid modernization by taking the following actions: (1) determine, with stakeholder input, the best way to maximize TVR-related benefits of AMF in a world where basic service participation is declining; (2) open proceedings or other stakeholder processes to develop state-wide data access protocols and to further develop the Commonwealth's TVR policies and implementation; and (3) require the Company to update its BCA and, particularly, to update its TVR study to ensure accurate estimates of the benefits of capacity and energy savings.

III. PROCEDURAL HISTORY

On August 19, 2015, National Grid filed its petition for approval of its Grid Modernization Plan. The Department docketed this matter as D.P.U. 15-121. On June 14, 2016 the Company filed updates to its GMP and related attachments, exhibits and testimony.

Pursuant to G.L. c. 12, § 11E (a), on August 13, 2015, the AGO filed a notice of its statutory right to intervene. On the same date, pursuant to G.L. c. 12, § 11E(b), the AGO determined that it was necessary and appropriate to retain one or more experts or consultants to assist in this proceeding and filed with the Department a Notice of Retention of Experts and Consultants. Neither the Company nor any other party filed comments on the AGO's Notices, which were allowed by the Department on September 2, 2015.

The following parties filed Petitions for full intervention status: Massachusetts Department of Energy Resources ("DOER"); the Low-Income Weatherization and Fuel Assistance Program Network (the "Low-Income Network"); Acadia Center; Cape Light Compact; Energy Freedom Coalition of America, LLC ("EFCA"); Conservation Law Foundation ("CLF"); Direct Energy; and the Retail Energy Supply Association. On April 14, 2016, the Department granted full intervention status to DOER; the Low-Income Network; CLF; and Acadia Center. The Cape Light Compact was denied full participant status, but granted limited participant status.

On May 26, 2016, the Hearing Officers denied as untimely the petitions of Direct Energy and Retail Energy Supply Association. This ruling was appealed to the Department on June 1, 2016 by Direct Energy, and the Department affirmed the Hearing Officers' ruling on March 3, 2017.

Also on May 26, 2016, the Hearing Officers denied full intervention status, but granted limited participant status to EFCA. This ruling was appealed to the Department on June 1, 2016 by EFCA, and then to the Supreme Judicial Court on February 8, 2017. The Department affirmed the Hearing Officers' May 26 ruling on March 3, 2107.

In addition, the Department granted the following Petitions for Limited Participant status: NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource"); NRG Energy, Inc.; Applied Materials, Inc.; Utilidata, Inc.; ChargePoint, Inc.; Northeast Clean Energy Council, Inc.; and Energy Consumers Alliance of New England d/b/a Mass Energy.

Over the course of the proceeding, the AGO, the Department and other parties issued hundreds of information requests. The Department conducted four days of evidentiary hearings between May 24 and May 31, 2017. During the evidentiary hearings, the Company presented nine witnesses: Peter T. Zschokke, Jeremy J. Newberger, Robert Sheridan, James R. Perkinson, William Jones, Mousami Bhakta, Mukund Ravipaty, Scott M. McCabe, and Amy S. Tabor. The AGO presented pre-filed direct testimony of three witnesses: Messrs. Gregory Booth, Peter Brown, and Paul Alvarez. Acadia Center presented one witness: Abigail Anthony. CLF presented three witnesses: Caroline Golin, Tim Woolf, and Ariel Horowitz.

IV. <u>STANDARD OF REVIEW</u>

The Department is charged by law with ensuring just and reasonable rates for the provision of electricity distribution services. G.L. c. 164, §94 ("Section 94"); *Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid*, D.P.U. 15-155, p. 301 (2016). Rates are set prospectively to provide an efficiently managed enterprise with sufficient revenues to recover reasonable expenses incurred in the provision of safe and reliable electricity service, including a fair investment return on, and of, prudently-invested shareholder capital [cite].

In establishing just and reasonable rates, the Department customarily relies on a regulated company's actual, historical test year revenues, expenditures and operating data, adjusted for known and measurable changes, as the most representative proxy of a company's prospective revenues, expenses and net capital additions (*i.e.*, "rate base"). Thus, Department ratemaking does not consider or allow customer rates to reflect or recover a company's *projected* levels of future capital plant additions not yet "in service." D.P.U. 12-76-B, pp. 20-22. Rather, such future capital expenditures are typically incorporated into rates *after* they are incurred, through a subsequent general rate case filed pursuant to Section 94. For the Department to incorporate historical capital plant additions into a Section 94 revenue requirement analysis a company must show the capital investment was prudent and necessary and that the resulting investment is used and/or useful in the provision of regulated service. *Western Massachusetts Electric Company*, D.P.U. 85-270, p. 20 (1986).

The Department, in a series of orders in both D.P.U. 12-76 and in its associated investigation in D.P.U. 14-04 into TVR, described its vision for a modern electric system thoughtfully planned to be "cleaner, more efficient and reliable, and [able to] empower customers to manage and reduce their energy costs." D.P.U. 12-76-B, p. 1. In setting forth its modernization vision, however, the Department also opined that modifications to conventional regulatory treatment of grid modernization capital expenditures may be warranted "to remove what may be impediments to some grid modernization investments" under traditional, customary ratemaking practices governing incremental capital investments. D.P.U. 12-76-B, p. 4; p. 19; p. 22.

Accordingly, in D.P.U. 12-76-B, the Department established a targeted capital cost recovery mechanism—STIP—to allow for periodic interim adjustments in rates for qualifying, incremental grid modernization capital spending without the need for a full Section 94 revenue requirement determination. The STIP allows for rate adjustments only in limited circumstances.

First, STIP-eligible investments must advance measureable company progress towards the Department's four grid modernization objectives and the individual projects must be proposed and incurred within the first five years of a company's GMP (D.P.U. 12-76-B, pp. 22-23). Although the Department's initial STIP proposal would have limited eligible STIP investments *solely to* capital additions to deploy advanced metering functionality ("AMF"),[2] the Department in D.P.U. 12-76-B subsequently allowed recovery for other grid modernization investments provided the GMP includes a plan to achieve advanced metering functionality within five years of Department approval of the GMP, or an alternative proposal to achieve advanced metering functionality across a longer timeframe. *Id.*, p. 17. "In other words," the Department determined, "targeted cost recovery will not be available for other [non-AMF] capital investments if the company is not also investing in advanced metering functionality." *Id.*, p. 20.

Second, the Department restricted qualifying STIP investments to capital expenditures only. Thus, a company may not recover projected O&M expense increases through the STIP. D.P.U. 12-76-B at pp. 16; 19.

---

[2] The Department took care to define "advanced metering functionality" (or "AMF"), as opposed to pre-determining specific characteristics of advanced metering infrastructure (or "AMI"). The Department defines AMF as:

> (1) the collection of customers' interval data, in near real time, usable for settlement in the ISO-NE [wholesale] energy and ancillary services markets; (2) automated outage and restoration notification; (3) two-way communication between customers and the electric distribution company; and (4) with a customer's permission, communications with and control of appliances.

D.P.U. 12-76-B at 15.

Third, a company may recover only *incremental* grid modernization capital spending through the STIP. The Department explained that the "incremental" prerequisite means either proposed capital investment in new system technologies, or an incremental level of proposed capital spending relative to a company's current capital expense program. D.P.U. 12-76-B at pp. 19-20. The Department cautioned, however, that the incremental limitation in the STIP means the proposed STIP spending "must be incremental to those [capital expenditures] recovered in base rates to be recovered in a capital tracker" and that "[c]ompanies will be required to demonstrate that such [proposed STIP] costs are not already included in rates." D.P.U. 12-76-B at 23.

Fourth, STIP-eligible investments must be prudently incurred. The Department explained that its review of the GMP and approval of proposed capital spending within the STIP would effectively serve as "pre-authorization" of STIP-eligible investments, foreclosing subsequent ratemaking challenges regarding whether the company should have proceeded, as a matter of necessity, with the STIP investments. D.P.U. 12-76-B at 19. But pre-authorization of STIP investments, the Department cautioned, would <u>not</u> foreclose subsequent inquiry and determination whether a company's spending in furtherance of the investment was prudent. *Id.*, p. 24. "[T]he company will bear the burden of demonstrating that all of the costs it seeks to recover through its [STIP] tracker were undertaken in a prudent manner." *Id.* In addition, Department pre-authorization through the STIP does not negate the ratemaking prerequisite that investments included in rates must be "used and useful," with one limited exception. STIP investments incurred towards company deployment of advanced metering functionality, but not used or useful in the year in which recovery is sought, may nonetheless merit targeted rate recognition provided the investment qualifies as construction work in progress. *Id.*, pp. 24-25.

The Department also stated that its consideration and pre-authorization of a company's STIP-eligible investments must be supported with a comprehensive business case analysis. D.P.U. 12-76-B at 17. The specific provisions and parameters of the required business case analysis are described at length in a subsequent Department order, D.P.U. 12-76-C. The Department underscored the importance of the business case analysis by stating that it "intends to look to the business case analysis as the primary lens for deciding whether to accept, reject, or require modifications to the STIP." D.P.U. 12-76-B, p. 17. It is through the business case analysis that a company demonstrates that the benefits of its STIP investments justify the costs. D.P.U. 12-76-C, pp. 3, 8, 12.

Finally, the Department determined that targeted, exceptional capital cost recovery via STIP-related rate surcharges would proceed annually, but terminate with the five-year STIP. D.P.U. 12-76-B, p. 25, n. 24. With the elimination of STIP rate increases in Year Five, STIP investments may be eligible for inclusion in rate base in a company's next general distribution base rate case, under traditional ratemaking conventions. *Id.*

V. <u>EVALUATION OF GRID-FACING MODERNIZATION INVESTMENTS</u>

A. Background

The AGO separately evaluated National Grid's proposed "grid-facing" (or "grid-focused") investments and planned investments for "customer-facing" modernization programs. In this Section, the AGO sets forth its recommendations regarding the Company's grid-facing planned capital additions undertaken to automate grid operations and allow electric distribution companies to more pro-actively monitor and control grid field conditions in near real time. Section V, *infra*, includes the AGO's recommendations regarding the Company's proposed customer-facing grid modernization expenditures.

The AGO retained the consulting services of Mr. Gregory Booth, of PowerServices, Inc., to evaluate National Grid's proposed grid-facing modernization planning. Mr. Booth has over forty years' experience evaluating, engineering, designing and building electric utility distribution infrastructure across the nation. Exh. AG-GLB-1, pp. 3-4. Mr. Booth has worked with both investor-owned utilities as well as extensively with municipally-owned power systems. On behalf of utility clients, large and small, Mr. Booth and his firm have extensive experience in grid modernization initiatives, including projects to design and manage the construction and integration of distributed generation facilities, both solar PV and wind. *Id.*, p. 6. He also has developed and delivered to utility clients grid modernization plans involving advanced meter reading/advanced metering infrastructure; SCADA systems; advanced relay technology; self-healing architecture; Volt/VAr optimization; and the development of time varying rates. *Id.*

Mr. Booth focused his review of the Company's proposed grid-facing capital budgets through the lens of prior experience reviewing grid modernization progress across the country. Exh. AG-GLB-1 at p. 9. Mr. Booth enunciated four threshold or elemental considerations for any successful grid modernization initiative:

(1) First and foremost, the proposed capital spending should advance the four grid modernization goals identified by the Department in D.P.U. 12-76-B (*i.e.*, reduce the effect of outages; optimize demand; integrate DER; and improve workforce and asset management);

(2) To warrant exceptional, expedited cost recovery via a capital tracker (*i.e.*, the STIP), the modernization investments must be "incremental," in the sense that the proposed capital projects are not the same ones the Company would choose to meet current "business as usual" capital spending obligations for the grid;

(3) The projects should present the opportunity for benefit, to the system and the customer; and

(4) Past experiences, good or bad, other utilities gained through undertaking similar investments should guide implementation in Massachusetts.

Exh. AG-GLB-1 at pp. 9. These four threshold considerations enabled the AGO to properly evaluate and prioritize the Company's grid modernization investment proposals; specifically, the AGO undertook to evaluate whether the Department should (1) accept and approve the investment proposals as eligible for STIP cost recovery; (2) approve them as pre-authorized for STIP recovery, but with qualifying conditions; or (3) exclude them from the Plan and the STIP because no added investment incentive or exceptional cost recovery assurance mechanism is necessary—the utility would make such investments in its own self-interest, in the ordinary course of business, and the costs are already included in base distribution rates. *Id.*, pp. 12-13.

During the evidentiary hearings, there was further exploration regarding this latter category of proposed STIP investments – excluded from the GMP as ordinary "business as usual" capital spending. Tr. Vol. J-2, pp. 139-140. Mr. Booth took care to underscore that the business as usual investments he identified and properly excluded as not undertaken for modernization were <u>not</u> being challenged as unnecessary or imprudent. *Id.*, p. 155; Exh. AG-GLB-1, p. 13. Nor was Mr. Booth challenging whether the investment might relate to the Department's grid modernization goals. Tr. Vol. J-2, p. 154. He also did not claim that the Company should be precluded from recovering such investments through distribution rates. Rather, Mr. Booth's testimony sought to demonstrate that certain aspects of system "modernization" occur automatically, as the technology and grid capabilities evolve naturally. Id., p. 146. As a consequence, a base level of "modernization" is achieved by the Company with little applied effort through on-going, "business as usual" capital spending to meet present business obligations, and such spending is already supported in base distribution rates.

The threshold distinction Mr. Booth drew between grid modernization progress achieved through "business as usual" investments and modernization advancement the Department should incent through the STIP is an important one, discussed with specific examples below. The Department designed the STIP to accelerate "incremental" modernization investments, meaning those investments representing a new, more advanced technology than the utility would otherwise deploy, or capital spending at a pace or level higher than that underlying base distribution rates. D.P.U. 12-76-B, p. 19. The STIP was designed to "eliminate barriers to grid modernization." D.P.U. 12-76-B, p. 22. If, however, the investment represents what the Company would purchase in any event in the ordinary course of capital acquisition planning, plainly no such "barrier" exists. Additionally, the Department emphasized that expedited cost recovery through the STIP must "be incremental to costs recovered in base rates." *Id.*, p. 23. A Company's ordinary capital construction program and spending levels is already "built into" base distribution rates (via a ratemaking allowance for both depreciation expense, taxes and a return on net investment).[3]

[3] National Grid explained that its base level of planned capital expenditures, over a five-year planning horizon, for both meeting its franchise service obligations and discretionary capital projects, averages $272 million. Exh. GMP Updated, Table 4, p. 24.

Accordingly, incorporating the same "business as usual" capital projects into a STIP would over-compensate the Company and force customers to unreasonably pay twice for the same investment. Exh. AG-GLB-1, p. 14.

Mr. Booth observed that, despite the differences in investment options across the four Company-proposed GMP scenarios, most investment for three of the four scenarios was associated with the deployment of AMF and the evolution towards ADMS. Exh. AG-GLB-1, p. 11. Both AMF and ADMS rely on various devices placed in the field, but also require substantial communications infrastructure to support and operate effectively. Given the AGO's recommendation in this proceeding to delay implementation of AMF (discussed further under Section VI, *infra*), Mr. Booth described the Company's "Grid-Focused" scenario, but with curtailed spending towards AMI, as the best means of moving forward on grid-facing modernization deployment. *Id.*, p. 12. By scaling back the deployment timeframe for AMI, Mr. Booth observed, the Company could scale back significant planned investments on its proposed RF mesh communications infrastructure (termed the Field Area Network, or "FAN"). Instead, the Company could utilize existing public cellular network services for the communications infrastructure to support its ADMS. Exh. AG-GLB-1, p. 12.

Because National Grid's GMP complies with the Department's requirements in D.P.U. 12-76-B by including plans for full AMF deployment (even though the AGO does not support moving forward with AMF at this time), all of the grid-facing investment that Mr. Booth determined properly belongs in a GMP is eligible for inclusion in the STIP. Accordingly, for the grid-facing investments, the Department should pre-authorize the STIP investments and the Company should be permitted to proceed, subject to the conditions and qualifications Mr. Booth recommends, as discussed further below.

Mr. Booth explained that the Company's proposed grid-facing investments were clustered in three principal categories: Field Deployment; Enabling Infrastructure; and Other Required Components. Exh. AG-GLB-1, pp. 21-22. Mr. Booth credits the Company's presentation of planned investment costs as based on solid foundational planning with its vendors, through both requests for information ("RFIs") and requests for proposals ("RFPs"). *Id.,* p. 23. National Grid then selected the vendor with the highest cost submission (as a sort of "worst-case" procurement outcome). Thus the Company commendably presents the Department with what Mr. Booth termed a realistic and "conservative" estimate of proposed capital budgets. *Id*.

B. Field Deployment Investments Are Generally Appropriate

The grid-facing elements in the Company's proposed Field Deployment investment plans include planned enhancements to: Conservation Voltage Reduction/Volt-VAr Optimizaion ("CVR/VVO"); Advanced Distribution Automation ("ADA"); and Feeder Monitors modernization investments. While there are variations in spending levels across the four alternative GMP scenarios proposed by National Grid, Mr. Booth estimated that funding for all "Field Deployment" initiatives (*i.e.*, CVR/VVO, ADA and Feeder Monitors) should approximate $66.38 million over the initial five year STIP and $245.27 million proposed over the full ten-year modernization planning cycle. Exh. AG-GLB-1, p. 25.

With limited qualifications discussed below, Mr. Booth recommends that the Department adopt National Grid's planned five-year STIP spending on Field Deployment.

1. <u>CVR/VVO</u>

Modulating distribution voltage levels as a means of conserving energy is not a new concept. Mr. Booth explained, however, that existing grid configurations offer only limited ability to manipulate both energy voltage (Volts) and reactive power (VAr) due to limited stand-alone system metering and telemetry and mostly manual switching controls. Exh. AG-GLB-1, p. 25. Operators today can generally achieve acceptable voltage control, under fixed service conditions, but only in the vicinity of the controllers. However, modern proposed enhancements through VVO and communications-capable field devices, added line voltage sensing, a robust communications network and an integrated Volt-VAr system controller offer the capability of far-reaching modulation in voltage and reactive power along the entire feeder, and under dynamic field conditions. *Id.*, pp. 27-28. Mr. Booth explained that the Company planned an initial deployment of VVO over 46 circuits in the first five years of the STIP, and then to add an additional 24 circuits annually in years six through ten of the GMP. *Id.*, p. 29. The targeted circuits were all individually reviewed, analyzed and selected by the Company as "high-value" candidates for VVO. *Id.*

Mr. Booth fully supported the Company's planned CVR/VVO deployment. In fact, Mr. Booth noted, the delay in Company-proposed investing in AMF recommended by the AGO would offer the opportunity to accelerate planned investing for VVO. Exh. AG-GLB-1, p. 31. Although a delay in planned investments in AMF would also postpone planned Company investments in the FAN communications infrastructure, National Grid can proceed nonetheless with communications infrastructure for CVR/VVO through greater reliance on public cellular communications. *Id.*[4]

[4] Mr. Booth observed that the Company's planned communications infrastructure investments include both private communications network (*e.g.*, RF-based FAN, microwave and fiber optic facilities) and public cellular investments (Exh. AG-GLB-1, p. 19). It is not always clear in the Company's communications planning which type of investment (private or public network) is being contemplated (*id.*).

Moreover, because the projected benefits National Grid ascribes to CVR/VVO are among the largest in the Company's business case analysis (Exh. AG-GLB-1, p. 31), deployment in this area should proceed as quickly as possible.

2. Advanced Distribution Automation (ADA)

ADA is the enabling investment for Fault Location Isolation and Service Restoration ("FLISR"), sometimes referred to as "self-healing" circuits. ADA brings field communications and automated controls and supervision to formerly stand-alone circuit devices. Exh. AG-GLB-1, pp. 31-32. The Company proposed deploying FLISR/ADA on 46 feeder circuits within the five-year STIP window, with an additional 24 feeders added annually in years six through ten of the GMP. *Id.*, pp. 33-34. The Company substantiated the case for ADA deployment with a claimed 25 percent estimated reduction in customer minutes of interruption made possible through ADA deployment. *Id.*, p. 35. Mr. Booth noted that the Company appeared to link its planned feeder deployment of ADA with its planned feeder deployment for CVR/VVO. *Id.*, pp. 34- 35.

Mr. Booth could not give unqualified support, however, for the Company's ADA deployment. Instead he found the Company should proceed with ADA, but with a less aggressive pace of deployment than for CVR/VVO. Exh. AG-GLB-1, p. 35-36. Mr. Booth urged that the Company's ADA deployment the first five years be limited to only 12 circuits (not the 46 feeders initially contemplated by National Grid) and that such investment be treated by the Company as a "pilot" to confirm technology capabilities, need, performance and cost. *Id*. That way, the pilot could be used to determine whether the equipment works as contemplated and, more importantly, whether a need can be confirmed.

3. Field Monitors

Field monitor investments describe the deployment of advanced sensing technology for distribution systems, capable of monitoring the conditions (voltage, current, etc.) and quality of energy along a feeder route and, through remote telemetry, bringing the accumulated data back for analysis and system coordination in near real time. Exh. AG-GLB-1, p. 36. Like many of the promised efficiencies of the modern grid, such sensing telemetry is largely dependent upon supporting investment in communications infrastructure. *Id.* National Grid plans in its five-year spending plan to roll out field monitors to 469 overhead and 137 underground distribution circuits. *Id*. Initially the Company would install the devices on the substation ends of the feeder, and the circuits selected for these devices would be different from the ones selected for the proposed CVR/VVO or FLISR deployment programs. *Id.*, p. 38.

Mr. Booth was generally supportive of National Grid's planned deployment of field monitor devices. But because the deferral of AMF recommended by the AGO would likely impact the Company's communications infrastructure roll-out, Mr. Booth cautioned that the deployment of field monitors would require additional communications planning. Exh. AG-GLB-1, p. 39. He therefore recommended the Company undertake a detailed assessment of the 469 targeted overhead circuits and additional system study work for the targeted underground circuits, including coordination of 13.8kV/4kV step down transformers where voltage conversion is an option. *Id.*, p. 39.

C. Proposed Spending on Enabling Infrastructure Includes Many Customary "Business-as Usual" Investments

The Company's planned investments for the field deployment portion of the GMP all require specific supporting investments in "enabling infrastructure." *See generally* Exh. GMP

Updated, Section 5, p. 60 *et seq*. Enabling infrastructure investments proposed by National Grid fall into four broad categories: Telecommunications/Operational Technology; DSCADA; ADMS; and Workforce Training and Asset Management ("WTAM"). Exh. AG-GLB-1, p. 41. The Company describes eleven separate investment components to its Enabling Infrastructure plans. However, four of the planned eleven components are no more than the customary evolutionary investments in existing processes that the Company would make as part of its "business-as-usual" base level of planned capital improvements and do not merit consideration for targeted, exceptional cost recovery through the STIP. *Id.*, pp. 41-42. In addition, Mr. Booth observed, the deferral of AMF deployment recommended by the AGO (and the associated spending on enabling communications infrastructure related to AMI) occasions a re-examination of the Company's enabling investment plans. *Id.*

First and foremost, Mr. Booth recommended the Company undertake a comprehensive communications study that would incorporate a delayed deployment of AMF and present the results to the Department for review. Exh. AG-GLB-1, pp. 42-43. The plan should emphasize investments in the Company's core private communications backbone, extending to all substations, whether by fiber, microwave and/or public cellular technologies. *Id*.

By contrast, however, the Company's proposed spending to enhance an Integrated Network Operating Center ("INOC") and system changes to Customer Service Systems, Meter Inventory Tracking Systems, Global Information Systems, and a new Data Lake and Analytics capability do not merit inclusion in the GMP. Mr. Booth explained that investments of this nature are required as part of an electric distribution utility's present and on-going service obligations and are not properly "triggered" by grid modernization spending. Exh. AG-GLB-1, pp. 42-44. Thus, properly considered, not all of National Grid's enabling projects satisfy the threshold consideration for grid modernization that the proposed investment represents new technology or incremental planned spending because investments of this nature would be made by the Company even if grid modernization were not formally adopted, in the ordinary course of safely and reliably managing its present system obligations.

Mr. Booth did not oppose the enabling investments National Grid proposes for DSCADA. His only cautionary counsel was that DSCADA investments in Year One of the GMP be coordinated closely with the recommended communications infrastructure study that should also transpire in Year One. Exh. AG-GLB-1, pp. 44-45.

Likewise, Mr. Booth found the Company's proposed investments in ADMS technologies sound, scalable, and properly linked to DSCADA deployment. Exh. AG-GLB-1, p. 45. He pointed out, however, that equipment for ADMS and DSCADA need not be selected from the same vendor, as the Company seemingly concluded, *provided* the vendor devices can be coordinated with each other, as was accomplished by a National Rural Electric Coop Association initiative called "Multi-Speak." *Id.*

In the area of Company-proposed spending on Workforce Training and Asset Management ("WTAM"), Mr. Booth recommended excluding from the STIP all of the proposed investments but one—advanced technology training. Exh. AG-GLB-1, p. 46. Proposed spending in all other areas of WTAM, Mr. Booth determined, is duplicative of the routine, business-as-usual investments the Company would make even in the absence of grid modernization initiatives:

> [Investments in] "Map Access and Feedback" and mobile tools such as truck laptops has been deployed by utilities and service companies as normal business technology deployment for many years. This is not a grid modernization component; it is only automating an existing paper or

> manual process. The "Electronic as Built Data Collection" falls into this exact same category. For years, utilities have migrated their paper maps to a digital GPS location system. Again, this is using well-established hardware and software to advance past paper and manual systems to the next generation of system maps, data, and personnel access to the data. This is inappropriate, and does not constitute a true GMP program. The time entry upgrade interfacing with its SAP time entry to, as the Company states in Mr. Perkinson's testimony on pages 56-57, reduce reliance on paper based processes but has no place in a GMP. This is only automating an antiquated paper process. "Electr[onic] Standards and EOPs" is, once again, only making a paper document electronically accessible. Utilities long ago proceeded to this point. The "Full Electronic Asset Inspection" is an area which should be a GMP technology, however, National Grid is only taking manual paper processes and automating or transitioning to electronic format. This, again, fails to fall into the GMP model.

Exh. AG-GLB-1, pp. 46-47.

It bears repeating that Mr. Booth did <u>not</u> challenge such investments as imprudent or unnecessary. His point is that spending of this nature is – or properly should be – already a part of a company's base level capital spending, undertaken to support present day service obligations and system requirements.[5] Exh. AG-GLB-1, pp. 46-47. Thus, customers have already "paid" in base distribution rates to support such investments, and including them separately for exceptional cost recovery via the STIP would over-compensate electric distribution companies for the same investments.

D. Other Required Components – Distributed Generation

National Grid also proposed certain targeted system upgrades associated with its initiative to support growing levels of distributed generation ("DG"). These investments include ground fault detection ("3VO") and Point to Multi-Point Power Line Carrier Permissive Direct Transfer

---

[5] Mr. Booth testified that certain WTAM initiatives proposed by National Grid were "easily a decade behind the point they should have been implemented" (Exh. AG-GLB-1, p. 47). "Just because National Grid has certain customary business functions still being performed in an antiquated manner does not mean advancing [now] to at least the [early] 21st century constitutes a grid modernization technology" (*id.*).

Trip protection ("P2MP PLCP DTT"). GMP Updated, p. 128. The Company noted, however, such investments are not included in its proposed GMP budget requests, as the Company anticipates recovery of such investments separately through its interconnection tariffs. *Id.*

Mr. Booth reviewed the Company's proposal and divided the Company's planned DG spending into three primary categories: 3VO protective relay; P2MP DTT relay scheme; and analytical tools, data storage and communications. Exh. AG-GLB-1, p. 49. Mr. Booth acknowledged that the 3VO and DTT systems result in a protection scheme that assures IEEE Standard 1547 compliance. *Id.*, p. 50. He also agreed such costs should properly be recovered from the interconnecting DG resource, not the Company's base distribution customers. *Id.*

Although Mr. Booth fully supported the proposed technologies, he could not unreservedly approve the Company's planned DG investments. Mr. Booth was troubled by the prospect that the Company intended to deploy these investments on a speculative basis in advance of any established interconnection need. Exh. AG-GLB-1, p. 50. Instead, he cautioned such investments should only be undertaken by the Company once there is a confirmed need for the protection and that deployment at a specific individual site will directly support an immediate increase in hosting capacity. *Id.*

Finally, Mr. Booth endorsed the Company's proposed spending on interconnection tools and screen applications. Exh. AG-GLB-1, pp. 50-51.

E. AGO Proposed Budgets

National Grid's planning budget for grid-facing investments varies with each of its four proposed alternative investment scenarios. While Mr. Booth found the Company's cost estimates mostly sound and supported by both RFIs and RFPs, the interdependency of the many components, across the four alternative scenarios complicates the task to fix and recommend a specific grid-facing budget. Exh. AG-GLB-1, p. 52-53. As a point of departure for an AGO-recommended budget for the grid facing investments, Mr. Booth relied on the ten-year capital spending levels of $521.3 million presented in National Grid's "Opt-in" scenario. *Id.*, p. 53. The Company would need to propose separate line-by-line adjustments to this starting budget in order for the Company to accommodate the AGO's recommendations to individual components (such as the exclusion of "business as usual" investments and the recommended deferral of AMF-related investments). But Mr. Booth deduced that the resulting ten-year GMP budget levels likely would be far closer to the $500 million in the "Opt-in" scenario than the $1.3 billion proposed in the "Balanced Plan." *Id.*, p. 53. Upon Department confirmation of the appropriate planning scenario, the Department should direct, before pre-authorizing grid-facing investments, that the Company prepare revised budgets and associated business case analysis reflecting the revised budget levels. *Id.*

VI. <u>EVALUATION OF CUSTOMER-FACING MODERNIZATION INVESTMENTS</u>

In D.P.U. 12-76-B, the Department identified AMF as a key component to meeting the Department's four grid modernization objectives D.P.U. 12-76-B., p. 14. Accordingly, the Company includes some level of AMF in each of its proposed GMP scenarios. Further, depending on the GMP scenario, the Company would offer the following rates to basic service customers with an installed advanced meter (*i.e.*, AMI) as either an Opt-out or Opt-in rate structure: a time-of-use rate ("TOU") with a Critical Peak Price ("CPP") component; and (2) an option to opt-out of the default rate and choose a flat rate with a Peak-Time Rebate ("PTR"). The Company's rate offering under the GMP would be similar to its rate offerings in its Worcester Smart Energy Systems ("SES") pilot.

The circumstances under which the Company will install AMI meters differs in each scenario. Under the Balanced Scenario and AMI-Focused Scenario, within five years, the Company would install AMI meters at every customer's premises that does not opt-out. Under the Grid Focused Scenario and "Opt-in" Scenario, the Company would install AMI meters only for customers that ask for one. The Company prefers the Balanced Scenario.

A. AMF Has the Potential to Provide Significant Ratepayer Benefits Under the Correct Regulatory Construct

In D.P.U. 12-76-B, the Department recognized the important role that AMF plays in modernizing the grid. The Department found that AMF is a "basic technology platform for grid modernization" that will further all four of the Department's grid modernization objectives. D.P.U. 12-76-B, p. 13; see also D.P.U. 12-76-A, p. 12. The Department recognized AMF's potential to deliver quantifiable and unquantifiable benefits to customers. There is no doubt that AMF has the potential to deliver benefits to a wide array of stakeholders including, customers, electric companies, competitive suppliers, demand response providers, distributed generation owners and third party vendors.

For example, a major feature of AMF is the recording of customer energy usage by date and time of day. Access to this data can further customer choice and control, lower overall electricity costs and improve grid operations. AMF can enable the aggregation of customers' actions reducing peak energy use, which can lower electric company operations and maintenance costs and provide long-infrastructure savings. *See* Exh. AG-PA-1, p. 13. AMF can facilitate our clean energy future, helping integrate distributed generation, electric vehicles, and energy storage.

AMF also can have positive impacts on the economy and the Commonwealth's greenhouse gas emission requirements. *See* St. 2008, ch. 298.

Despite the Department's recognition of AMF's potential to deliver customer benefits, the Department did not find in D.P.U. 12-76-B that Companies should implement AMF at any cost. Rather, the Department required that STIP capital investments be supported by a comprehensive business case analysis. *Id.* p. 3. The purpose of the business case analysis is to allow the Department and other parties to "evaluate whether the benefits, both quantified and unquantified, justify the costs of the proposed STIP investments." D.P.U. 12-76-C, p. 3. The Department also required each company to present an overall assessment of whether its business case justifies the proposed investment. D.P.U. 12-76-C, p. 4.

AMF deployment at any level will facilitate ratepayer benefits. The question is (1) whether the Company's GMP captures enough ratepayer benefits to justify the high cost of AMF, which include the actual meters, communications capabilities and other back-office-type system; and if not (2) what actions do the Company, the Department, and Stakeholders need to take to unleash the full panoply of ratepayer benefits of AMF at the lowest possible cost.

As discussed further below, the Company's GMP, as currently presented and under the current regulatory structure, does not provide enough ratepayer benefits to justify the costs. Therefore, the Department should not allow the Company to utilize the special rate recovery mechanism outlined in D.P.U. 12-76-B (the STIP) for AMF deployment at this time. The Company's GMP, does however, provide insight into actions that Department and other stakeholders can take to maximize the benefits that customers receive from AMF and to minimum the costs. These actions are discussed further below in Section IV.E.

B. The Company's GMP, as currently presented under the current regulatory structure, does not provide sufficient ratepayer benefits to justify the costs of AMF

As the Department required, the Company's GMP includes a business case analysis in which its assessed the benefit-cost ratio for each of its proposed scenarios:

Scenario	Company's Calculated Benefit-Cost Ratio
AMI-Focused	1.08
Balanced	.94
Grid Focused and "Opt-In"	.57

Exh. GMP Updated, p. 133, Table 20. Thus, under the Company's analysis, only the AMI-focused scenario results in a positive benefit-cost ratio. However, as noted by the Department and the Company, a negative cost benefit ratio does not automatically result in a denial of the proposal by the Department. Rather, it is important to look at all elements of the Company's proposal, quantifiable and unquantifiable, to determine whether the benefits justify the costs. In this case, after careful review, the AGO has concluded that existing conditions, which hinder the Company's ability to capture sufficient benefits of AMF, challenge the Company's business case assumptions.

For an AMF component of a GMP to be justified, the Company must maximize all potential benefits associated with the high costs of purchasing and installing new meters, and building out the associated communications, back-office, and other technical systems. Around the country, AMF deployment typically delivers the greatest benefit to ratepayers by reducing or replacing the expense of employing the manual meter readers needed for traditional meters. Exh. AG-PA-1, pp. 6-7. In Massachusetts, due to the previous deployment of AMR, this workforce is already minimal. Consequently, the Company cannot rely on the primary savings typically identified by their counterparts in other areas of the country to justify a business case analysis. Instead, the Company must turn to other benefits to fill the gap.

Here, the Company turns to the second largest savings mechanism typically initiated by AMF deployment, TVR and demand side management. Exh. AG-PA-1, p. 12. More than thirty-seven percent of the total quantifiable benefits in the Company's Balanced Scenario BCA ($356,002,511 out of $956,451,776) and more than 44 percent of the benefits in the AMI-Focused Scenario ($356,002,511 out of $801,163,215) are the result of TVR and demand side management. Exh. National Grid GMP, Attachments 10a and 10b. TVR benefits are the Company's forecast of the benefits that will flow from customers' use of time-varying rate. Here, the Company estimates that TVR will deliver more than 93 percent of the combined demand side management and TVR benefit of $356,002,511 in the Company's Balanced and AMI-focused scenarios. *Id*. Thus, to make up for the lack of meter reader replacement benefits, it is vital that the Company takes full advantage of these "demand response benefits" and in particular, the TVR benefits.

Maximizing TVR savings depends three primary determinants: (1) the number of customers that are using TVR rates, (2) how much these customers are reducing their demand (the average size of demand response); and (3) the value per unit of the demand reduced. As these determinants grow in size, so do the benefits. *Id*. at p. 13.

TVR Benefit Size = Number of Participating Customers × Average Size of Demand Response × Value Per Unit of Demand Reduced

Current conditions in Massachusetts effect each of these variables and the Company's use of them in its GMP. First, with the rapid migration to both competitive supply and municipal aggregation in recent years, the number of the Company's basic service customers (*i.e.*, the participating customers) is decreasing. This in turn, affects the savings available from default TVR for basic service customers. Second, the Company's assumptions regarding the size of the demand reduction it will achieve from TVR is overly optimistic. Third, the Department cannot rely on the value per unit of demand reduced employed by the Company in its TVR benefits calculations because it is based on old data and is inconsistent with the facts on the ground today.

1. <u>The accelerated migration of residential customers to competitive supply and municipal aggregation dilutes the potential for TVR savings.</u>

TVR savings are directly impacted by the Company's shrinking basic service customer base, driven largely by the adoption of municipal aggregation plans. While under its Balanced and AMI-Focused Scenarios the Company proposes to install AMF for all customers who do not opt-out, the Company only offers TVR to basic service customers. GMP Updated, pp. 19, 21, 48. Similarly, the scaled back Grid-Focused and "Opt-in" Scenarios limit TVR to basic service customers who Opt-in to both AMF and TVR. GMP Updated, p. 22-23. In its BCA, the Company assumes between 66 percent and 71 percent of its customers will participate in rates with demand response features. Exh. AG-3-31, Att. AG-3-31(b), Tab 13.DSM, line 233. Yet, if all pending municipal aggregation plans identified in the Company's service territory are approved, only 48 percent of the Company's distribution customers will be served by basic service. Exh. DPU 5-11(a). Indeed, four of the identified municipalities, the Towns of Bellingham, Foxboro, Grafton and Nantucket, are now active aggregations. Thus, at a minimum, the assumptions the Company made in its BCA about customer participation are out of date. With fewer participating customers on basic service, the Company will draw smaller TVR benefits from the same amount of investment. To achieve the savings numbers assumed in the BCA, either competitive supply and/or municipal aggregation customers would need to return to the Company's basic service rate or a very large percentage of these customers would need to participate in TVR through their current provider.

2. The Company's Demand Reduction Assumptions Are Inconsistent with Real World Results.

In its BCA, the Company assumes that its basic service customers' use of TVR will result in an 8.4 percent demand reduction based on a review by Concentric Energy Advisors of 14 TVR studies completed by utilities across the nation. Exh. National Grid GMP, Attachment 13. Several factors indicate that this number may be too optimistic. First, in its SES Pilot in the City of Worcester, the Company reports achieving a 5.4 percent summer residential demand reduction over a two-year period, using a weighted average of customers utilizing a variety of enabling technologies, such as in-home displays and programmable, communicating thermostats. Exh. NG Panel-Rebuttal-2, p. 7.[6] The Company's TVR plan for its GMP was modelled on the SES. Exh.

[6] In the SES, of the 15,000 customers offered an AMI meter, nearly 11,000 enrolled. In addition to the meters, the Company provided customer-facing technologies and TOU/CPP/PTR rates. The Company identified a subset of those enrolled as "active customers," or customers who either opted-in to free home technologies or who logged into the Pilot web portal at least once. Exh. NG-Panel-Rebuttal-2, p. 31. These active customers represent less than 25 percent of all enrolled participants, but represent the majority of the achieved capacity savings during a Conservation Day Peak Event. Id. at p. 133.

NG-Panel-Rebuttal-1, p.18. Between the Concentric Energy Advisors review (8.4% reduction) and the SES pilot results (5.4% reduction), the SES pilot results are more relevant and should be used to estimate TVR benefits in the Company's BCA. The review by Concentric Energy Advisors is less reliable, as the 14 studies reviewed were conducted in a number of climates much different from the Company's. Exh. National Grid GMP, Attachment 13. Climate affects demand reductions significantly, as the prevalence and usage of air conditioning is very different from climate to climate. The geographies and various climates represented in the 14 studies include 9 studies conducted in California, Oklahoma, and several mid-Atlantic states with much higher air conditioning loads than in Massachusetts. *Id*. It is very likely that higher air conditioning loads lead to higher demand reduction opportunities and results. Yet the Company's BCA uses the demand reductions from the Concentric Energy Advisors review rather than the results of its own SES pilot with its own customers in its own climate.

Second, in the SES, the Company offered SES participants free enabling technologies (*e.g.*, in-home displays and programmable, communicating thermostats) to encourage demand reductions. Exh. NG Panel-Rebuttal-2, p. 7. The Company does not propose to offer this free technology to GMP TVR participants through the GMP, but rather, the Company will make the technology available through its energy efficiency plan. Exh. GMP Updated, p. 63. Thus, the SES participants had more favorable conditions for demand reduction than the GMP TRV customers will. This fact further challenges the assumption that the Company will achieve more savings in the GMP TVR plan than it did in the SES.

3. The Department cannot rely on the Company's estimated TVR benefits because they are based on old data and are inconsistent with the facts on the ground today.

The largest function in the Company's BCA for the Balanced and AMI-Focused scenarios is $333 million of claimed benefits the Company forecasts customers will receive by the avoided energy and capacity costs from TVR. Exh. National Grid GMP, Attachment 10a and 10b, Tab 5, "Summary—Benefits and Costs." Of the $333 million, $286 million is attributable to avoided capacity costs, while $47 million is attributable to electricity supply costs savings.[7] Exh. National Grid GMP, Attachment 10a and 10b, Tab 5, "Summary—Benefits and Costs." The Company derived these estimates from an April 30, 2015 study the electric distribution companies commissioned, "Electricity Market Price Forecasts for Massachusetts," prepared by Tabors, Caramanis and Rudkevich (the "TCR Study"). Exh. NG GMP, Attachment 11. The TCR Study is based upon the assumptions, and uses the same methodology to value capacity and energy, as the Avoided Energy Supply Costs in New England (2015 AESC) study used in connection with the Commonwealth's statewide Three-Year Energy Efficiency planning. Exh. NG GMP, Attachment 11, p. 4.[8]

The TCR Study relies on data available in 2014 and early 2015, data over two years old. In the last two years, substantial changes have occurred in the regional electricity market and with

[7] In its updated GMP, the Company's estimate of capacity and energy benefits are slightly higher than $333 million, but in the same ball park. To avoid questions about confidentiality, the Attorney General uses the original publicly available numbers.

[8] The Company seems to argue that because the TCR Study utilizes standard modelling methods that have been used in the state's energy efficiency programs, the Study's assumptions or methods cannot be questioned. Yet, the Department has found that a "company's use of data or forecasts, as well as any underlying assumptions, from other proceedings will not preclude parties to the GMP proceedings from fully investigating those inputs within the GMP proceedings." D.P.U. 12-76-C at 16.

federal taxation rules that will significantly impact both energy and capacity prices. These changes challenge the assumptions and conclusions of the TCR Study. In particular, TCR's estimate of future capacity and energy costs, are based, in part, on assumptions about new generating facilities and renewable energy tax incentives. In the TCR Study, these assumptions were based on the state of the law and markets in 2014-15.

Yet, since the TCR Study was prepared in 2014-2015, the laws and regulations for renewable energy in Massachusetts have dramatically changed. First, subsequently enacted legislation requires very large additions of renewable energy into the Massachusetts power market. Massachusetts law now requires that the Massachusetts distribution utilities solicit for 9.45 million megawatt hours of new clean energy. This equates to the addition of approximately 1,200 megawatts of clean energy capacity by 2022. G.L. ch. 188, Sec. 12. Likewise, Massachusetts law requires that the Massachusetts distribution utilities solicit for 1,600 megawatts of offshore wind by the year 2027. *Id.* The law requires the distribution companies to solicit for no less than 400 megawatts of offshore wind capacity every other year over the next eight years so that they are contracting for a total 1,600 megawatts by 2027. *Id.* Further, the Massachusetts Department of Energy Resources recently issued emergency regulations for the Solar Massachusetts Renewable Target (SMART) Program, creating a solar incentive program pursuant to Chapter 75 of the Acts of 2016. *See* 225 CMR 20.05. The regulations, issued this year, provide financial incentives for the addition of 1,600 MW of new solar photovoltaic (PV) capacity in Massachusetts with expectations that it will be built in the next several years. The addition of these large increments of solar, clean energy, and offshore wind capacity could result in market price suppression, both individually and collectively,[9] or have impacts on peak demand. The TCR Study does not reflect these new additions in its price forecasts. Thus, the price effects have not been reflected in the Company's estimate of projected TVR costs or benefits.

Second, the TCR Study assumes that the federal Production Tax Credit for wind energy would end on December 31, 2016, and that the Investment Tax Credit for solar energy projects would be eliminated, resulting in large increases in prices for wind and solar energy. In fact, Congress extended both the Production Tax Credit for wind energy and the Investment Tax Credit for solar projects. The TCR Study does not reflect how extending these tax credits will impact its assumptions regarding capacity.

Third, real world results from the Forward Capacity Auctions that occurred in 2016 (setting capacity prices for 2019-2020) and 2017 (setting capacity prices for 2020-2021) lead to further questions about the soundness of the Company's assumptions about avoided capacity costs. For instance, the TCR Study assumes that wholesale Forward Capacity Market Prices for years 2020 and 2021 will be $138 /kW-year and $136 /kW-year, respectively. *See* GMP, Attachment 11, p. 42, Exhibit 2-3. The Company's avoided capacity value assumption for Massachusetts utilities during this same time period is almost $200 /kW-year. Attachment 12, Appendix B pp. 308-315, column f. Yet, when the Independent System Operator of New England ("ISO-NE") held its

---

[9] The addition of such large increments of renewable energy that is sold into the energy market is similar to that provided by the Cape Wind offshore wind contract, where the Department recognized the very significant impact of planned renewable capacity additions on the capacity and energy market through price suppression. *See e.g. Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid,* D.P.U. 10-54, pp. 104-108 and pp. 120-132 (2010) ["In conclusion, the Department expects that price suppression effects on National Grid customers from 234 MW of PPA-1 will be in the range of $87 to $124 million, in present value dollars."]

auction to determine the contract (*i.e.*, actual) capacity market prices for 2019-2020 and 2020-2021, the actual price was significantly lower -- $84 and $63 /kW-year, respectively.

While the Company argues that a complicated model cannot be expected to track any particular year's actual price, the large disparity for those years when FCM prices reflect an excess of generation between auction prices and the TCR Study's predictions, coupled with the changes that have occurred in the Massachusetts and federal regulatory landscape over the last two years that can be expected to add to existing generation supply, raises sufficient doubts about the value of demand and energy reductions from TVR in the Company's BCA. Because the estimated capacity and energy benefits from TVR is such a large component of the Company's BCA, the Department should require the Company to update its study on the benefits of TVR. This study should include the new developments discussed above and, as discussed in Section IV.E.4 below, an analysis of the benefits of selling peak reductions from TVR into the forward capacity market.

C. The Company Fails to Include All Relevant Costs in its BCA Cost Estimates

Because the Company leaves out many cost elements typically required in a regulatory analysis of a utility investment, the BCA benefit cost ratios are overstated. In particular, the BCA fails to include in its cost estimates: contingency factors for capital projects (typically ten percent); the federal and state income taxes on the return on common equity; municipal property taxes; and, the cost of removal for plant in service charged through depreciation expense.[10]

Typically, significant plant addition cost estimates include a ten percent contingency cost adder, while information technology additions include a twenty percent contingency cost adder.

[10] While the BCA fails to include these costs, the Company recognizes them as part of its revenue requirement for the STIP. Ex. PTZ-1 Updated, p. 21; Exh. CRP-1, pp. 16, 26-29; Tr. p.370.

The Company is familiar with the importance of planning for such contingencies, yet added neither of these contingency factor costs in its BCA. Indeed, its SES Pilot suffered from costs overages of more than 30 percent over budget.[11] *See National Grid Recovery of 2015 Smart Grid Pilot Program Costs*, D.P.U. 16-28, Exh. AG DMB-1 (Redacted), p. 10-12 and Exh. AG-1-13.

The Company, when preparing its project cost estimates in this case, also failed to include many capital-related costs that it will charge to customers. Such costs include the federal and state income taxes on the return on common equity and municipal property taxes that will be charged to customers. *See* Department Order in D.P.U. 15-155, pp. 527, 526. Further, the Company failed to include the cost of removal for the plant in service that will charge through the depreciation expense.

The Company's failure to include in its cost estimates contingency factors for capital projects and its omission of income taxes, property taxes, and the cost of removal in the cost estimates means that its capital project cost estimates are grossly understated. This also means that all of the associated benefit-cost ratios are overstated. The Department cannot determine if the benefits of the BCA justify the costs when the costs estimates are not accurate.

D. The Company Fails to Demonstrate that the Benefits of its Opt-in Scenarios Justifies the Costs.

The failure of National Grid's Grid-Focused and Opt-in Scenarios to deliver a positive benefit-cost ratio is not surprising because partial deployment or Opt-in constructs do not result in enough customers participating in TVR to capture the full benefit potential of advanced metering

[11] The Company's USFP SAP project implementation went more than 200 percent over budget. National Grid, D.P.U. 15-155, pp. 294-295.

deployment. *See* D.P.U. 12-76-B., p. 48 (an Opt-in plan, particularly one which charges customers for installation, fails to maximize customer participation and therefore diminishes its benefits). Indeed, both the Grid-Focused and "Opt-in" Scenarios are predicted to only produce a .57 benefit-cost ratio. GMP Updated, p. 16, Table 1. The benefits do not justify the costs. In order to reach maximum customer participation and therefore benefits, AMF deployment requires widespread deployment on an "opt-out" basis, coupled with a default basic service product that includes a TVR. D.P.U. 14-04-B, p. 8.[12] As discussed below, the Department has better options to make progress on AMF than Opt-in deployment. Opt-in AMF deployment is simply not a cost-effective plan for ratepayers.

E. The Company's GMP provides insight into, and foundational steps for, achieving beneficial AMF deployment

To fully realize the benefits of AMF, Massachusetts needs a regulatory construct that allows the many complimentary pieces of the grid modernization puzzle to fit together. As noted above, a key benefit of AMF is that it allows customers to reduce their use during peak times. In Massachusetts, demand side management, and particularly, peak demand reductions through TVR, offers the greatest portion of potential benefits from AMF. For customers to realize the full benefits from demand side management, thereby maximizing the largest category of benefits to justify a business case analysis, each of the puzzle pieces must fit together. To achieve this will require (1) maximizing participation in demand reductions from TVR by all distribution

[12] The Company is not alone in attempting to address some of the Department's objectives by proposing an Opt-in arrangement. In fact, each of the distribution companies presented an Opt-in AMF deployment scenario and each scenario resulted in negative benefit-cost ratios for customers. Eversource estimates its Opt-in deployment scenario will provide $0.27 in benefits for every $1.00 spent while Unitil's estimate is $0.49 for every $1 spent. *See* Eversource, D.P.U. 15-122, Exh. Eversource-IGMP (2017), p. 63, Table 12 (Opt-in Approach 5% Participation); Unitil, D.P.U. 15-121, Exh. Unitil GMP BCA Model STIP Totals – STIP v2 7_8_15-Programs.

customers, regardless of supplier; (2) maximizing demand response per TVR participant by requiring standardized data access protocols state-wide data access protocols; (3) the further development of TVR policies which drive TVR-related benefits; and (4) updating the TVR study to better understand the benefits and drivers of the benefits of capacity and energy savings.

1. <u>To maximize ratepayer savings and system benefits, all customers, regardless of generation supplier, should have access to TVR.</u>

In order to maximize the ratepayer benefits from TVR and provide justification for the cost of deploying AFM, TVR must be offered to all distribution customers, regardless of supplier. The Company argues that this can be achieved by the Company working with municipal aggregations and even competitive suppliers to establish a TVR for the suppliers to offer their customers. Tr., pp. 160-161. The Company reports that the Cities of Worcester and Lowell have expressed interest in offering TVR to their residents that are receiving supply from municipal aggregations. Exh. NG-Panel-Rebuttal-1, p.13. Exh. AG-9-3. Tr., pp. 51-53, 157-161. While this willingness is encouraging, the Company provided little information about how such an offering would be designed, who would guarantee the supply rates, and if there are suppliers interested in serving a city's load in this way.

Similarly, *maybe* municipal aggregators "…would actually propose a time-varying rate on their own going forward," and competitive suppliers "…hopefully …[will] promote time-varying rates themselves," but there is simply no guarantee that municipal aggregations or competitive suppliers will have the information, willingness, or inclination to offer TVR.[13] In addition, as

[13] The Company points to Texas as the standard for incorporating time-varying rates and the competitive supply market. Exh. NG Panel-Rebuttal-1, p. 12. Massachusetts is not Texas. First, Texas distribution companies are prohibited from offering basic service, so all customers are on some sort of competitive supply. Tr., p. 54. Second, the independent system operator in Texas, the Electricity Reliability Council of Texas, levies capacity charges on competitive suppliers according to customer use during system peak, rather than energy sales volume, as is done in

indicated by AGO Witness Paul Alvarez and the Department in D.P.U. 14-04-C, simply offering TVR as an option is insufficient to deliver the participation levels available from default application of TVR. Without further regulations or incentives, leaving it up to the third-party supply market to offer time-varying rates, even with vague utility assistance, does not provide adequate assurance regarding the realization of benefits to justify large AMF costs.

In order to maximize the ratepayer benefits from TVR and provide justification for the cost of deploying AFM, TVR participation must be maximized for all distribution customers, regardless of supplier. The Attorney General recommends that, with stakeholder input, the Department determine the best way to maximize TVR participation in a world where basic service participation is declining. Options to consider include expanding distribution company administered PTR to all customers regardless of supplier (an approach pioneered by the Maryland Public Service Commission)[14] or advocating to ISO-NE that capacity costs should be directly charged, on a per customer basis, to municipal aggregators and competitive suppliers (the approach utilized by the Electric Reliability Council of Texas[15]).

2. Establish Data Access Protocols to Maximize Demand Response per TVR Participant

As the Department noted, AMF can provide customers with the "ability to make informed decisions about energy use and adopt cost-saving technologies and services." D.P.U. 12-76-B, p.

ISO-NE. Tr. Vol J-2, p.193-194. Thus, Texas customers must take competitive supply and competitive suppliers have an incentive to reduce customer load during a peak event in order to reduce their capacity charges. Even with these economic incentives, adoption of true TVR in Texas (rather than free Saturdays and the like) is likely less ten per cent of residential customers. Tr. Vol. J-2, p. 232.

[14] In Maryland, a state with retail choice and full AMF deployment, the electric utilities calculate and pay PTR for all distribution customers, regardless of electric supplier. Exh. AG-PA-1, pp. 16-17, Tr. Vol. J-2, pp. 196-197

[15] *See* Tr. J-2, pp. 191-199.

14. Simply installing AMF or employing default TVR, however, will not easily nor automatically change customer behavior. The easier it is for customers to reduce demand during a peak period event, through the use of enabling technologies and services, the larger the associated demand reductions will be. Both the Company and third parties have the potential to maximize customer response during peak periods by reducing the effort required from the customer during the event. Absent clarifications around competitive curtailment service offerings and data access, only the Company currently has the clear ability to provide customer assistance. A vibrant third party market for energy management services could serve to maximize the associated ratepayer benefits of AMF deployment and minimize the customer cost and inconvenience of managing TVR.

Establishing a platform to enable this market requires defined regulatory oversight to protect consumers and facilitate the convenient exchange of information between third party vendors and the Company. Properly defining and overseeing the security of, access to, timing of, and uses of energy usage data, as the Department indicated it would in D.P.U. 12-76-A, will allow the Company to make definitive conclusions about the benefits promised. Doing so will also encourage the development of a vibrant energy management services market, to the advantage of individual customers and to the Company's program benefit assumptions. Critical to enabling these benefits is a standardized approach to access energy usage to the data collected by AMI meters. As an example, the Green Button "Connect My Data" is a nationwide standard developed to allow a customer to authorize a service provider for ongoing access to that customers' energy usage data. Exh. AG-PA-1, p. 21. "Connect My Data" allows automated, secure information exchange via the automated delivery of data. Contrast that to the "Download My Data" portal, which is a good idea but which does not provide the more appropriate level of access to data for customers working with a third party service provider, and ultimately, to maximize demand reduction benefits from AMF. Use of a national standard like Connect My Data will ensure Massachusetts consumers have access to energy management services and software available now or in development for consumers throughout the nation. Failure to embrace such a national standard will require services and software providers to develop individual approaches to individual utilities, severely constraining the availability of such services and software to Massachusetts consumers.

Perhaps in recognition of the potential for increased benefits from appropriate data access, the Company pledges to make "Connect My Data" available to its customers. Tr., pp. 57-59. The Department should ensure that the Company follows through with this pledge and make this standard of interval data access a requirement of any AMF deployment authorized. Notwithstanding this forward-thinking pledge by the Company, the AGO also requests that the Department open a generic proceeding to establish the standard protocols for data access and curtailment services for all distribution companies, in an effort to standardize the treatment of data and maximize its potential benefits. To that end, the proceeding should examine: (1) the protection of customer data privacy; (2) access to data by customers and authorized third parties; (3) timing and availability of data; and (4) uses of aggregated interval data (including who can and should use it) as the Department indicated it would do in D.P.U. 12-76-A.

3. The Department Should Establish Statewide Parameters for Implementing TVR to Maximize the Benefits and Protect Ratepayers

As noted above, the Department has established a standard for grid modernization that includes widespread AMF deployment to all customers (unless a customer affirmatively "optedout" of receiving advanced meters), coupled with TVR as the default basic service rate. D.P.U. 12-76-B, p. 48; D.P.U. 14-04-B, pp 5-10; D.P.U. 14-04-C, p. 21. The Department further adopted a basic framework for the elements of a TVR mechanism. D.P.U. 12-76-C, p 20; D.P.U. 14-04-C, pp. 21. Mainly, this framework requires companies to include a *default* basic service offering of a TOU rate, with a CPP, though customers may opt-out in favor of a flat rate with PTR. D.P.U. 12-76-C, pp. 20-22; D.P.U. 14-04-C, p. 21.

As the Department recognized in D.P.U. 14-04-C, 20, there are a number of other issues that need to be resolved before TVR is implemented in Massachusetts. Among the issues listed by the Department in D.P.U. 14-04-C were: rate design considerations, low income protections, administrative changes, any necessary modifications to the basic service procurement process, and protocols for the treatment of customers who opt out of advanced metering technologies. *Id.* During this proceeding, parties raised these and others issues that need further attention by the Department.[16]

For example, in addition to the issues raised by the Department in D.P.U. 14-04-C, the Department should consider and establish statewide parameters for peak demand events. These parameters would address questions such as: who is most appropriate to call the peak demand event day – the individual distribution company, the Department, ISO-NE, or some other third party decision maker? Will consecutive peak days be called, and if so, how many can be called in a row? How will peak demand periods be defined? In the SES Pilot, the Company defined a CPP

[16] In its May 26, 2016 Interlocutory Order on Scope of Proceeding, the Department declined to review the Company's specific rate design for TVR as part of the Department's review of the GMP. National Grid GMP, D.P.U. 15-120, Interlocutory Order on Scope of Proceeding, p. 5. However, the Department indicated that it would address in this case the appropriate methods to consider TVR rate design in a future proceeding. *Id*.

event the day before by designating specific event hours. Exh. NG-Panel-Rebuttal-2, pp. 4, 13. Will maximum benefits come from replicating the flexibility of event-designated hours according to peak load predictions, or to set a fixed peak demand period for a season or year in order to simplify the process for customers? Related, should different peak demand periods be defined for the summer and winter seasons? And if so, should seasonal peak periods be tied to a seasonal capacity product, if one is designed by ISO-NE?

The Department also should consider the parameters for PTR. This would include answering questions such as: how will PTR behavior changes be calculated? How will the baseline be established? How often will rewards be distributed? Finally, the Department should consider whether changes that have occurred since 2014 raise any additional issues that should be considered before TVR is implemented in Massachusetts.

By mandating TOU with CPP as the default basic service rate, the Department has taken the first steps to deliver AMF benefits to customers. Now, the Department should provide additional guidance regarding how this rate design will be implemented across the state. Establishing consistent requirements for TOU, CPP and PTR for all distribution companies will maximum benefits by increasing the potential for aggregated and more meaningful, peak demand benefit reductions. The Department should open a new proceeding to establish directives, statewide for the implementation of TVR.[17]

[17] In D.P.U. 14-04-C, the Department indicated that it would be addressing implementation issues through a stakeholder process. Whether through a stakeholder process or a more formal Department proceeding, the Department should ensure that all interested parties have the opportunity to participate.

4. The Company's Updated Study Should Include an Analysis of the Customer Benefits of Selling Capacity into the Forward Capacity Market

TVR, particularly a TVR that includes a CPP feature, can result in significant demand reductions. *See* Exh. AG-PA-1, p 10 (citing Connecticut study delivering a 16 percent reduction in peak period demand). However, to monetize these demand reductions, they must be recognized and realized in the ISO-NE wholesale markets. There are two possible ways for customers to obtain value from TVR in the ISO-NE Forward Capacity Market. First, if customers' participation in TVR lowers peak demand, this lower demand over time could reduce the amount of capacity (what ISO-NE terms the Installed Capacity Requirement, or "ICR") that needs to be acquired in the Forward Capacity Auction ("FCA") (Option One). Second, if allowed by market rules, a distribution company or a third party could aggregate and bid into the FCA customers' peak load reduction, as is currently allowed for demand response and energy efficiency programs ("Option Two").

The Company states that its BCA benefit analysis is based solely on Option One. NG Panel-Rebuttal-1 at 14. The AESC study, focusing on potential cost savings for the distribution company, values Option One higher than Option Two. *See* GMP, Attachment 12, Appendix B (compare "kw sold in FCA" with "kw purchased from the FCA"). While both Option One and Option Two would receive the same forward capacity market price from the wholesale market, the AESC study uses a higher multiplier for Option One (1.377 for line loss, reserve requirements, and wholesale risk) than for Option Two (1.08 for line loss). Exh. DPU 5-20 citing AG-3-31-(a) (CONFIDENTIAL), Att. Tab/sheet 54, cells H9, H10 and H11. According to the AESC study, these multipliers are "additional" costs on top of the wholesale market price that a company avoids when it does not have to purchase as much capacity. However, the AESC study also recognizes that the total amount of avoided capacity cost is lower for Option One vs. Option Two because benefits accrue to customers in Option Two faster (three years) than for Option One (four years).[18]

As recognized by Mr. Alvarez, Option Two is not currently possible under ISO-NE capacity market rules. This is because TVR results in peak demand reductions in the summer, but ISO-NE defines capacity as a year-round product. Exh. AG-PA-1, p. 18-19. Because TVR capacity and energy savings benefits are such a large component of the benefits from AMF, it is important to ensure that any plan by the Company maximizes all TVR-related benefits. Thus, the Department should require the Company in its updated TVR benefits study to determine the difference in customer benefits, if any, between Option One and Option Two, and how a utility may optimize the value from its investments facilitated through the ISO-NE markets. The study should consider, among other issues, (1) the value of both options to customers; (2) the length of the time lag and the impact that it has on value; (3) the appropriate use of multipliers; and (4) other factors that may make one option better for customers than the other. To ensure that all options are available, the Company and other stakeholders should work with ISO-NE to establish a seasonal capacity market that would allow utilities or third parties to bid aggregated demand reductions into the FCM (*i.e.*, Option 2).

---

[18] "The total amount of avoided capacity costs is lower [for Option One] because of the time lag-up to four years-between the year in the kW reduction first causes a lower actual peak demand and the year in which ISO-NE translates that KW reduction into a reduction in the total ICR demand for which capacity has to be acquired in an FCA. Since the load reduction in one year will affect the allocation of capacity responsibility in the next year, the . . .customers experience a one-year delay in realized savings that are not bid into the auctions at all." See Company filing, Attachment 12, p. 19 n. 6.

The Company's proposed AMF scenarios provide key insights into what benefits are available to ratepayers and achievable with the right regulatory construct. The AGO recommends that (1) the Department deny the Company's request for pre-authorization and special cost recovery for its AMF investments at this time; and (2) adopt the AGO's recommendations to help establish a regulatory framework that will allow customers to realize the benefits of AMF.

VII. THE COMPANY SHOULD CONDUCT REGULAR CYBERSECURITY VULNERABILITY ASSESSMENTS

As the grid modernizes and becomes more integrated across multiple technologies, the ever present threat that cyberattacks pose on energy security and customer privacy must be kept at the forefront of the Company's grid modernization planning. To this end, the Department required the Company to continually assess and upgrade defenses against cyberattacks, and to draw up plans on how it will prevent unauthorized access to control systems, operations, and data. D.P.U. 12-76-B, p. 34-35. The Company must also ensure that burgeoning volumes of customer information available through a modernized, digital grid remains private and that their data cannot be shared without customer approval. D.P.U. 12-76-B, p. 34-36. While the Company provides sufficient detail on certain defenses to cyberattacks and protecting customer aggregate data and their personal information, the Department should order regular assessments to confirm its effectiveness. Exh. AG-GLB/PB-1, p. 8-12.

While the Company provided a method to validate the implementation and operation of a cybersecurity plan, conducting regular Cyber Vulnerability Assessments (CVA) would enhance the Company's security controls. Exh. AG-GLB/PB-1, p. 13-14. A CVA is a technical audit of the cybersecurity measure that should be conducted both annually and with the implementation of a new technology to the cybersecurity program. Exh. AG-GLB/PB-1, p. 14. In its rebuttal testimony, the Company states that it already conducts risk evaluations of its cybersecurity assets and CVAs would be unnecessary. Exh. MR-Rebuttal-1, p. 5. However, regular, recurring CVAs are consistent with the industry standard as defined by the National Institute of Standards and Technology and would enhance the Company's commitment to protecting its GMP investments. Exh. AG-GLB/PB-1, p. 13.

VIII. AT THIS TIME, THE DEPARTMENT SHOULD NOT APPROVE ANY CUSTOMER EDUCATION AND OUTREACH SPENDING BEYOND THE COMPANY'S TRADITIONAL METHODS

As the Department has stated, "marketing, education, and outreach are vital to ensuring that customers are well informed about and engaged in: (1) their options for managing their energy consumption; (2) the tools and technologies that will assist them; and (3) the benefits associated with reductions in consumption and/or shifting consumption away from high-cost times." D.P.U. 12-76-B, p. 26. When capturing maximum grid modernization benefits is dependent on robust customer participation, as is the case here, a well-designed customer outreach and education plan is crucial. D.P.U. 12-76-B, p. 26.

In the short term, absent the benefits associated with meter reading, the reductions in customer bills from off-peak pricing, critical peak pricing and peak time rebates constitute the majority of direct customer benefits. Exh. AG-PA-1, p. 40-41. This customer usage strategy to save money by shifting the hours of energy consumption would mark a "fundamental change [] in the relationship between the companies and their customers." D.P.U. 12-76-B, p. 26. Thus, a GMP customer education and outreach plan should focus on informing customers how critical peak pricing and peak time rebates work, and how customers can leverage these rate features to reap the greatest savings. Exh. AG-PA-1, p. 40-41.

Here, because the AGO recommends that the Department not approve AMF investment at this time, there is no need for the Company to spend millions of dollars on an extensive, advanced customer education and outreach plan. Without AMF, the Company cannot fully implement its rate design proposal. Thus, it is simply too early for a successful campaign to educate all Company customers on how to best utilize time-of-use rates, critical peak pricing or peak time rebates.

The Company should, of course, communicate with its customers regarding other grid modernization components approved by the Department. However, these components do not require active customer participation to realize their benefits. As such, the Company does not need a more rigorous customer education and outreach plan at this time beyond its traditional manner of communication. Exh. AG-PA-1, p. 40-41. [19]

IX. THE COMPANY NEEDS TO DEVELOP ACTUAL PERFORMANCE METRICS

Evaluating the Company's subsequent execution of its approved GMP is necessary to confirm the Company's progress towards the Department's four grid modernization objectives. D.P.U. 12-76-B, p. 30. To this end, the Department directed the Company to establish two types of metrics: "(1) infrastructure metrics that track the implementation of grid modernization technologies and systems; and (2) performance metrics that measure progress towards the objectives of grid modernization." D.P.U. 12-76-B, p. 30. The Department ordered that these

[19] Should the Department approve the Company's deployment of AMF and TVR with critical peak pricing and/or peak time rebates, the Department should require the Company to utilize third parties to assist in educating customers. Third parties can play a critical role in helping to ensure customer participation. Exh. AG-PA-1, p. 40.

proposed metrics should include measurements of outcomes that may not be within the Company's complete control, and metrics that are not easily quantified. D.P.U. 12-76-B, p. 33. While the Company listed certain *infrastructure* metrics that would count the Company's progress on plan *inputs*, the Company falls short of optimally measuring successful *performance* of its GMP investment *outcomes*. The Company's proposed metrics measure the Company's activities themselves, and not the beneficial effects those activities are intended to produce on the grid and for customers.

Development of effective and accurate performance metrics follow a four step process: select and establish the appropriate metric; measure the baseline; set the target; and report the outcome. Exh. AG-PA-1, p. 34. Establishing the metric requires close consideration of a particular modernization goal for the investment and a clearly-defined method of measurement. Tr. Vol. J-2, p. 208-09; Exh. AG-PA-1, p. 34. Here, the Department has provided the Company with four over-arching goals of grid modernization to measure: reducing the effects of outages; optimizing demand; integrating distributed resources; and improving workforce and asset management. D.P.U. 12-76-B, p. 31-32. The Company's metrics, however, do not focus on its performance towards achieving these goals beyond infrastructure investment. Exh. AG-PA-1, p. 34. For example, to measure the reduction in the effects of outages, the Company proposes to measure the extent of its automation deployment and how many customers are served through new devices. Exh. National Grid GMP, p. 170, Table 24 – Statewide Performance Metrics. Such a proposed metric plainly does not measure the benefits of any grid automation towards improving reliability measures like SAIDI. Exh. AG-PA-1, p. 34. In contrast, Mr. Alvarez, provided numerous examples of performance-based metrics that the Company can implement. Attachment DPU-AG-

1-4. Accordingly, the Department should require the Company to establish true performance-based metrics that measure achievement towards securing the Department's four goals of grid modernization.

The next step in the metric development process, measuring the Company's pre-deployment baseline, verifies the current status of the grid and provides a reference point once deployment begins. Tr. Vol. J-2, p. 208-09; Exh. AG-PA-1, p. 34. Once baseline data is acquired and settled, optimistic, yet attainable targets should be created for the Company, with timeframes proposed that are in line with the Company's benefits projections. Exh. AG-PA-1, p. 34. Finally, as deployment of the GMP is underway, the Company should measure and timely report progress on its performance to the Department at least annually. Exh. AG-PA-1, p. 34.

The Company's current metrics measure its infrastructure build-out progress, but do not adequately measure the performance of this infrastructure. Following this four-step process described above to create proper performance metrics will provide invaluable data to both measure and confirm the GMP's customer benefits that can be used in assessing the Company's progress towards achieving the Department's four goals of grid modernization.

X. <u>CONCLUSION</u>

Consistent with the recommendations detailed herein, the Office of the Attorney General respectfully requests that the Department: (1) pre-authorize certain of the Company's proposed grid-facing investments; (2) deny pre-authorization of AMF investment; (3) utilize the information gained from the Company's GMP to open additional proceedings in the furtherance of grid modernization; and (4) require the Company to update its BCA.

Respectfully submitted,

/s/ Donald W. Boecke

Donald W. Boecke
Elizabeth Mahony
Joseph F. Dorfler
Assistant Attorneys General

Massachusetts Attorney General Maura Healey
Office of Ratepayer Advocacy
One Ashburton Place
Boston, MA 02108
617-963-2408

Dated: July 14, 2017

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, for Approval of its Grid Modernization Plan	)	D.P.U. 15-120

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in this proceeding in accordance with the requirements of 220 C.M.R. 1.05(1) (Department's Rules of Practice and Procedure). Dated at Boston, Massachusetts this 14th day of July, 2017.

/s/ Donald W. Boecke

Donald W. Boecke
Assistant Attorney General

Massachusetts Attorney General Martha Coakley
Office of Ratepayer Advocacy
One Ashburton Place
Boston, MA 02108
617-963-2408
donald.boecke@state.ma.us

cc: Service List