DPU 12-76
Massachusetts Electric Grid Modernization Stakeholder Working Group Process:

Report to the Department of Public Utilities from the Steering Committee

Facilitation/Consulting Team:
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Final Draft

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PREAMBLE

The Massachusetts Department of Public Utilities ("Department") opened this proceeding in order to solicit input from stakeholders on how to ensure that the Department's policies facilitate adoption of grid modernization technologies and practices by the electric distribution companies over the short, medium, and long term.[1] In this spirit, the Stakeholder Working Group developed this this Report in an open, collaborative process, through the participation of a number of stakeholders having key interest in the Grid Modernization investigation. Consequently, the substantive information and principles and recommendations contained in this Report come from a variety of perspectives. The information contained herein should prove useful to the Department when considering the scope and the issues that will need to be resolved in future proceedings.

Consistent with the Department's Notice of Investigation, the Working Group has made a good faith effort to discuss the recommendations and regulatory policies that may facilitate the modernization of the electric distribution system in Massachusetts for consideration by the Department. The Working Group has also made a good faith effort "to reach as much consensus as possible, presenting alternatives where consensus is not reached" within the relatively condensed time period allotted for this proceeding. Certainly all stakeholders agree that the distribution companies should continue to modernize the electric distribution system at some level. The recommendations in this Report made in Chapters 5 through 8 represent a consensus of all of the Steering Committee Members unless otherwise noted. Where a consensus was not reached by all of the Steering Committee members, options are presented with a description of which Members support each option.[2] These commonalities and differences help bear out key considerations for the Department as it moves forward.

The Report also reflects a good faith effort of the Stakeholder Working Group to gather information from published reports and presentations made to the Stakeholder Working Group during the course of the stakeholder process. To assist and inform the Department in evaluating the recommendations made within Chapters 5 through 8 of the Report, the Report provides a good deal of background and additional information. However, the facts, assumptions, and analyses contained primarily but not exclusively within Chapters 3 and 4 and the appendices of this Report were not evaluated by the Stakeholder Working Group or the Department in an adjudicatory process pursuant to G.L. c. 30A. For example, the preliminary cost information and other information and analysis reflected in this Report do not constitute substantive evidence required to justify any specific grid modernization investment or the related recovery of utility costs from customers. Implementation of any specific and significant grid modernization investment will require further evaluation and process in an adjudicatory proceeding.

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[1] NOI, p. 1.

[2] Furthermore, consistent with the Working Group groundrules, Steering Committee members organizations (and any other organization that adds its name to the Final Report—i.e., a signatory organization) can provide supporting information and supplemental comments to the DPU within the timeframe and format (e.g., page limit) specified by the DPU and consistent with State Administrative Procedure law (G.L. c. 30A), as long as such information and comments are not inconsistent with the positions taken by that signatory organization within the Final Report. Furthermore, nothing in this Report should be interpreted as a waiver of any rights or position that any Working Group member may take in any other proceeding before the Department, any court of law or equity, or any other adjudicatory body.

1. INTRODUCTION, PROCESS, AND REPORT OVERVIEW

This chapter briefly describes the three main components of the Massachusetts Department of Public Utilities (Department or DPU) electric grid modernization process leading up to this report: 1) the Department's Notice of Investigation; 2) Kick-Off Workshop; and 3) Stakeholder Working Group Process. The chapter ends with a brief introduction to the rest of this report.

1.1. Notice of Investigation

On October 2, 2012, the Department issued a notice of investigation "Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid" (D.P.U. 12-76)". The Department's stated purpose for the NOI was:

> The Department of Public Utilities ("Department") opens this inquiry to investigate policies that will enable Massachusetts electric distribution companies and their customers to take advantage of grid modernization opportunities. Specifically we will examine our policies to ensure that electric distribution companies adopt grid modernization technologies and practices in order to enhance the reliability of electricity service, reduce electricity costs, and empower customers to adopt new electricity technologies and better manage their use of electricity. The purpose of this investigation will be to solicit input from stakeholders that will guide the Department's approach to grid modernization over the short, medium, and long term. (NOI, page 1)

The NOI goes on to list eight separate opportunities that the Department expects grid modernization to offer (See Chapter 2 for listing of those opportunities), and then lays out the following 8 "areas of inquiry:"

- Current Status of Electric Grid Infrastructure as it Relates to Grid Modernization
- Grid-Facing Technologies
- Customer-Facing Technologies
- Time-Varying Rate Design
- Costs and Benefits of Grid Modernization
- Grid Modernization Policies
- The Pace of Grid Modernization Implementation; and
- Health, Interoperability, Cyber-security, and Privacy

Under each of these areas of inquiry, the Department posed two or three questions for stakeholders to consider (See Appendix 1). The Department also established a Grid Modernization Stakeholder Working Group to discuss "both grid-facing and customer-facing issues, including the questions posed in the NOI, and to develop recommendations to the Department." The Department hired the facilitation and consulting team of Raab Associates, Ltd. and Synapse Energy Economics to assist the DPU and run the stakeholder working group process.

1.2. Kick-Off Workshop

On November 14, 2012 the Department hosted its Electric Grid Modernization Working Group Kick-Off Workshop at the Federal Reserve Bank in Boston. The Workshop was attended by over 125 stakeholders, and included the following six distinct parts:

- MA DPU Electric Grid Modernization Vision and Key Questions (by the DPU Commissioners)
- MA Distribution Company Grid Modernization Grid- and Customer-Facing Activities & Plans (by NSTAR Electric Company, Western Massachusetts Electric Company, Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, and Fitchburg Gas and Electric Light Company d/b/a Unitil (collectively the "Distribution Companies")
- Status of Grid Modernization Efforts in U.S. (by GE Digital Energy & Brattle Group)
- Participant/Stakeholder Discussion: Grid Modernization Vision & Key Challenges (small group facilitated discussions with report back)
- Working Group Goals, Structure and Process (by Facilitation/Consulting Team)
- Closing Remarks (by the DPU Commissioners)

During the small group facilitated discussion on grid modernization vision & key challenges, the three most mentioned opportunities/benefits from grid modernization across the twelve groups were:

1) Enhanced reliability
2) Increased opportunity for distributed generation and other new technology to enable greater customer control of their electricity
3) Develop a better regulatory framework to foster grid modernization planning and investment

The three most mentioned concerns/barriers across the 12 groups were:

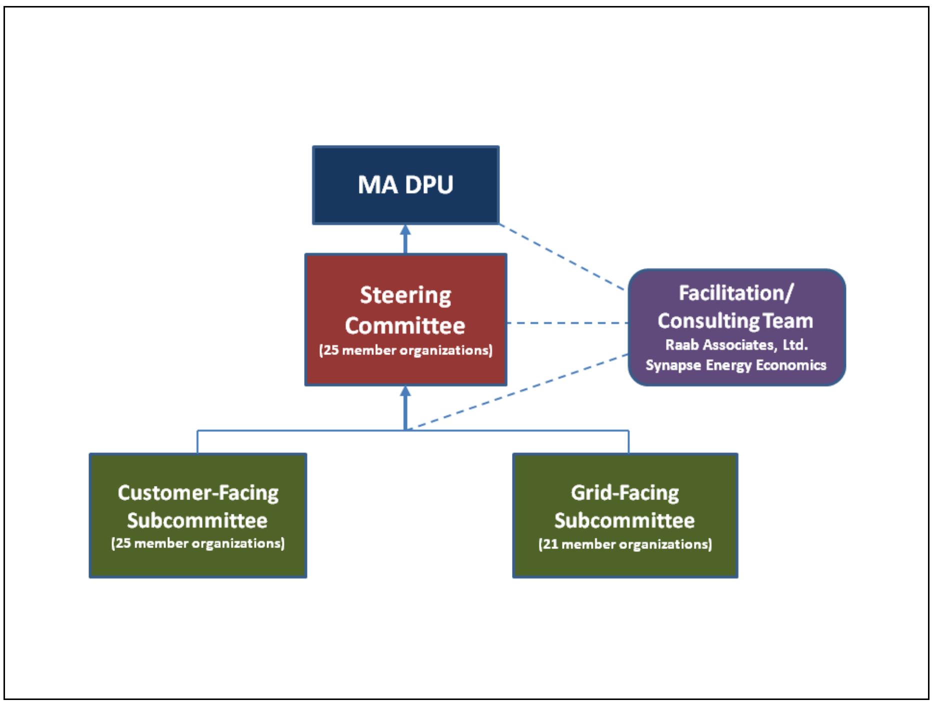
1) Potential costs of grid modernization technologies, policies, & programs
2) Cost-effectiveness of grid modernization technologies, policies, & programs
3) Incentives and cost recovery for Distribution Companies related to grid modernization investments

1.3. Stakeholder Working Group Process

In its NOI, the Department laid out its expectations and parameters of a Grid Modernization Stakeholder Working Group Process including:

- Beginning with a kick-off workshop, meeting through mid-June 2013, and filing a final report with the Department by June 19[3], 2013.
- Including full plenary sessions and at least two subcommittees (one focusing on grid-facing issues, and the other on customer-facing issues).
- Reaching as much agreement as possible on as many of the key grid modernization issues as possible, and identifying any such areas of agreement.
- Reporting the different views and options for those issues where agreement cannot be reached, and identifying which members support each view/option.
- Including the electric distribution companies and other interested stakeholder representatives in the Working Group process.
- Having the Department actively leading the Working Group process assisted by a facilitation and consulting team.

Figure 1-1: MA Grid Modernization Stakeholder Process



Following the Kick-Off Workshop the facilitation/consulting team of Raab Associates, Ltd. and Synapse Energy Economics worked with the DPU staff and Commissioners to finalize the structure, timeline, and membership of the stakeholder working group process. The structure of the stakeholder working group, as illustrated in Figure 1-1, was comprised of a Steering Committee and two Sub-Committees—one

[3] The Department changed the final report deadline to July 3rd to allow for additional review time by the members of the final report.

focused primarily on grid-facing technologies and issues and the other focused primarily on customer-facing technologies and issues.

The Steering Committee was comprised of 25 member organizations from state government, consumer and environmental groups, the Distribution Companies and ISO New England, competitive suppliers, and representatives from a wide range of clean energy companies and organizations (see below in Table 1-1 for Steering Committee Member Organizations). The DPU staff and a representative from the MA Executive Office of Energy and Environmental Affairs and representatives from the Department of Telecommunications & Cable participated in the Steering Committee as ex officio Members. The two subcommittees were comprised of representatives from the Steering Committee Organizations and their affiliates, as well as additional organizations not directly on the Steering Committee.[4] For a full listing of all the Steering Committee and Subcommittee Members and their representatives, see Appendix II.[5]

Table 1-1: Steering Committee Member Organizations

State Agencies (5)	**Clean Energy Cluster (9)**
MA Clean Energy Center	Bloom Energy & ClearEdge Power (Fuel Cells)
MA Dept. Telecom/Cable (ex officio)	ChargePoint (EV/Charging)
MA DOER	Conservation Services Group (Energy Efficiency)
MA DPU (ex officio)	Electricity Storage Association & AMBRI (Storage)
MA EOEEA (ex officio)	EnerNOC (Demand Response)
Utilities (4)	New England Clean Energy Council
National Grid	Northeast Clean Heat &Power Initiative (CHP)
NSTAR	Northeast Energy Efficiency Partnerships (EE)
Unitil	SEBANE/SEIA (Solar)
WMECO	**Environmental Groups (1)**
Independent System Operator (1)	ENE
ISO New England	**Competitive Suppliers (2)**
Consumer Groups (3)	Constellation
Low Income Network	Direct Energy
Cape Light Compact	
MA Office of the Attorney General	

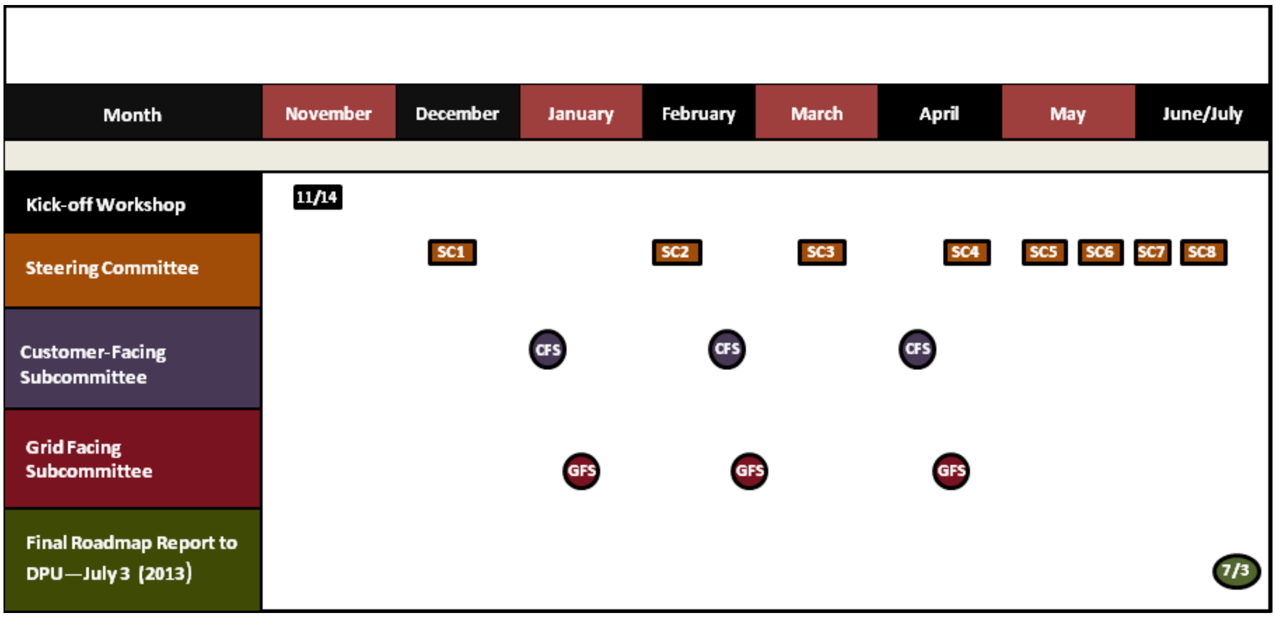
The Steering Committee had its first meeting in December 2012, and then met eight times altogether with its final meeting on June 17th of 2013. Each of the Subcommittees met three times between

[4] The two organizations formally invited to participate in the Grid-Facing and Customer-Facing Subcommittees as members who were not Steering Committee Member organizations or their affiliates were GE Digital Energy and IREC, respectively.

[5] The Department directed the Distribution Companies to participate as Members of the Working Group and determined the remaining Working Group Membership in consultation with the Facilitation/Consultant Team after solicitation and review of requests from interested persons, organizations, and groups.

January and April 2013, to pull together pertinent background information on grid-facing and customer-facing technologies and practices currently in use, as well as possible alternatives moving forward. The Subcommittees also brainstormed potential principles and recommendations for the Steering Committee's consideration and further development. The Steering Committee was responsible for completing the work begun by the Subcommittees, and also had the primary responsibility for addressing the issues that cut across both customer- and grid-facing strategies—such as regulatory policies (cost-effectiveness, cost-recovery), interoperability, and cyber-security. Figure 1-2 below shows the final constellation of meetings.

Figure 1-2: Stakeholder Process Timeline and Meetings



The working group stakeholder process was supported by a website where all of the agendas, meeting summaries, stakeholder groundrules, presentations, working documents, and a substantial library of background documents are all housed. The website also includes contact information for the members of the Steering Committee and both Subcommittees, as well as the schedule and location for all the meetings. The website will remain live for the foreseeable future and can be accessed at http://magrid.raabassociates.org/index.asp.

1.4. Overview of the Report

The remainder of this Report contains a variety of work products and recommendations from the Steering Committee.

Chapter 2 of this Report includes the goals and opportunities for grid modernization specified in the Department's NOI. It also includes a list of the potential barriers to grid modernization created by the current regulatory environment.

Chapter 3 includes a taxonomy of grid modernization for Massachusetts developed by the Grid-Facing Subcommittee and finalized by the Steering Committee, which includes the desired "outcomes" for grid modernization, as well as the activities, capabilities, and system enablers associated with those outcomes (subject to further evaluation by the DPU). The chapter also includes definitions for each of the terms used in the taxonomy.

Chapter 4 provides a brief summary and road map of the background information assembled largely by the Customer- and Grid-Facing Subcommittees or provided by the Distribution Companies. On the grid-facing side this background information provides some basic information about the Massachusetts Distribution Companies' current grid-facing system enabling technologies. On the customer-facing side, the background information includes high-level descriptions of the Distribution Companies' current TVR pilot programs, as well as their current metering technologies. The customer-facing background information also includes information of the incremental capabilities (aka functionality) of a range of metering technologies, as well as the cost range for those metering technologies and related system enablers.

Chapter 5 provides the Steering Committee's recommended principles related to over-arching, grid-facing, and customer-facing issues. Chapter 6 delineates the Steering Committee's recommended regulatory policies including regulatory oversight, ratemaking, and cost recovery for grid modernization investments. Chapter 7 provides various Cost-Effectiveness frameworks submitted by members of the Steering Committee. Finally, in Chapter 8 the Steering Committee lays out its recommendations related to some potential next process steps for the DPU to take in this docket.

The appendices to this Report provide additional information, and are referenced at the appropriate juncture in the body of the Report.

2. Goals, Objectives and Barriers

2.1. The Goals of Grid Modernization and the Working Group

To help establish regulatory policies and a road-map that will enable Massachusetts electric distribution companies, their customers, and other market participants to take advantage of grid modernization opportunities, both in the short-term and over the long-term.

Specifically, as specified in the NOI, to ensure that Massachusetts electric distribution companies, their customers, and other market participants adopt grid modernization technologies and practices to:[6]

- enhance the reliability of electricity services; (NOI p.1)
- reduce electricity costs; (NOI p.1)
- empower customers to better manage their use of electricity; (NOI p.1)
- develop a more efficient electricity system; (NOI p.3)
- promote clean energy resource;. (NOI p.3) and
- provide new customer service offerings. (NOI p.3)

Note that there may be tradeoffs in attempting to meet all these goals simultaneously, e.g., tradeoffs between enhanced reliability and reduced electricity costs.

2.2. Grid Modernization Opportunities

The Department's NOI identifies a number of grid modernization opportunities that the Stakeholder Working Group sought to evaluate and consider. The opportunities include:[7]

1. Reduce the frequency and duration of customer outages through automated, remote-controlled grid devices and real-time communication to the distribution companies of outages and infrastructure failures;
2. Provide customers with the information, price structures, technologies, incentives, and tools that can empower them to use electricity more efficiently and reduce their individual energy costs;
3. Improve the operational efficiency of the grid, particularly during peak times when the grid is most stressed and electricity is most expensive;
4. Reduce transmission and distribution system operation, maintenance, and construction costs by reducing electricity demands at times of system peaks;
5. Reduce New England wholesale and retail electricity costs by reducing electricity demand at times of system peaks;

[6] These are from the DPU's NOI.

[7] These eight opportunities are taken from the DPU NOI (pp. 3&4).

6. Facilitate the integration of distributed generation resources and new technologies, such as renewable energy technologies, combined heat and power, energy storage, fuel cells, and electric vehicles;
7. Enhance the success of the Massachusetts energy efficiency and other clean energy initiatives, through the use of marketing campaigns and the advancement of technologies that both reduce peak demand and save energy; and
8. Reduce greenhouse gas emissions from the electric sector by: increasing the operational efficiency of the grid, reducing the need for the high emissions generating plants that run primarily during times of peak electricity demand; empowering customers to use energy more efficiently; and facilitating the integration of demand resources into the grid.

2.3. Barriers to Implementing Grid Modernization under Current Regulatory Practices

[Distribution Companies/Clean Energy Caucus/MA DOER/Retailers/CLC][8] The following represent high-level barriers to Grid Modernization in Massachusetts. This is not an exhaustive or extensive list of barriers, but rather an effort to identify the key barriers the Department and interested stakeholders must overcome in order to advance Grid Modernization in Massachusetts.

1. **Cost Effectiveness**: Assessing the benefits and costs of Grid Modernization is a complex task. A framework for assessing cost-effectiveness needs to be defined.
2. **Regulatory Framework**: Current regulatory policies may not provide Distribution Companies with sufficient guidance regarding Grid Modernization investments. A framework for regulatory review and cost recovery needs to be established.
3. **Balancing Safety and Reliability**: Grid Modernization investments must be made in alignment with and support of the Distribution Companies' core responsibility to provide reliable and safe service to their customers.
4. **Customer Education**: Certain grid Modernization investments may require considerable customer education to inform and engage customers on various attributes of grid modernization programs
5. **Affordability**: Affordability of electricity service is a concern for many customers. In making future grid modernization investments that may deliver benefits to the system, the issue of affordability must be addressed.

[8] "**Utilities**" or "**Distribution Companies**" refers to Steering Committee Members NSTAR, National Grid, WMECO, and Unitil; "**Clean Energy Caucus**" is comprised of Steering Committee Members MA Clean Energy Center, ISO-New England, Bloom Energy & ClearEdge Power (Fuel Cells), ChargePoint (EV/Charging), Conservation Services Group (Energy Efficiency), Electricity Storage Association & AMBRI (Storage), EnerNOC (Demand Response), New England Clean Energy Council, Northeast Clean Heat & Power Initiative (CHP), Northeast Energy Efficiency Partnerships (EE), SEBANE/SEIA (Solar) and ENE;"**Retailers**" refers to Constellation and Direct Energy; "**CLC**" refers to the Cape Light Compact.

6. [CLC/Retailers**] Balancing Grid Modernization Investments and Competitive Energy Markets**: Competitive energy markets in New England and competitive electricity services in the Commonwealth may be impacted by grid modernization investments.

The MA Office of Attorney General (AGO) and Low Income Network (LIN) identify the following list of high-level barriers for the Department's consideration:

1. **Cost Effectiveness for Evaluating Customer-Facing**: Assessing the benefits and costs for certain customer-facing investments or programs requires additional consideration, and the framework for how to conduct and evaluate the cost-effectiveness of these programs needs to be established.
2. **Regulatory Framework**: A framework for regulatory review and cost recovery needs to be established for grid modernization investments and programs that will help ensure that: customers' rates are affordable, just and reasonable; that costs are allocated to customers based on cost allocation and assignment principles in place today, and; investments are least-cost, prudent and used-and useful.
3. **Balancing Safety and Reliability**: Grid Modernization investments must be made in alignment with and in support of the Distribution Companies' responsibility to provide reliable, safe, and least-cost service to customers at affordable.
4. **Affordability**: Distribution Companies' customers will likely be asked to pay for many future grid modernization investments. Investments into grid modernization may be more costly than traditional investments. Such investments could undermine the Distribution Companies' ability to achieve, maintain and promote affordable electricity rates and charges for all customers.
5. **Benefits**: Many of the benefits associated with some grid modernization investments and programs have not yet been demonstrated in full-scale implementation and may be experienced differently among customers who may be asked to pay for these investments.
6. **Customer Engagement**: In order to obtain some of the benefits of grid modernization it will be important to engage customers to participate in new or innovative programs. Customer engagement and sustainability may be uncertain, may vary significantly across customers, and may be highly dependent upon the types of technologies and programs offered them.
7. **Technological Change**: The pace of technological change, and the potential for technological obsolescence, increases the complexity of the issues and risks in evaluating some grid modernization investments.

3. Grid Modernization Taxonomy

3.1. Taxonomy

One key objective of the Department's investigation into grid modernization is to consider the range of capabilities that collectively define a modern distribution network. To that end, the Department posed the following question for the Working Group in the NOI: "What are the key grid-facing technologies and practices that the distribution companies should be implementing to maximize the reliability and the efficiency of the grid?"

To answer this question, the Working Group set out to develop a grid modernization taxonomy that captures those capabilities or activities that could be most relevant to Massachusetts' Distribution Companies. The taxonomy is included below in Figure 3-1. This effort drew upon a variety of resources, including the Distribution Companies' investment plans and 3rd-party reports, such as the US Department of Energy's assessments of Smart Grid Investment Grant projects funded by the Recovery Act of 2009.[9]

This chapter is a result of the Working Group's efforts. The chapter defines for the Department a range of potential capabilities, activities and enablers that may result in the desired potential outcomes. In practice, the use of each potential capability and enabler may be dependent upon many factors under consideration and evaluation by the Distribution Companies, consumer advocates, other stakeholders and the Department. The reader should not infer from this chapter that each desired potential outcome and the associated capabilities, activities and enablers is equally valuable or necessary. This determination is dependent on the facts and circumstances of each case. Consequently, this chapter does not address issues such as cost recovery, cost-effectiveness, affordability, or the Department's prudence and used and useful requirements for investments.

However, the Working Group was able to make substantial progress in identifying those outcomes, capabilities, activities and enablers that should be considered by the Department. The Working Group initially identified 14 core capabilities that could be deployed by Massachusetts Distribution Companies to support the grid modernization goals and opportunities highlighted in the Department's Notice. The Distribution Companies are deploying many of these core capabilities already. See below for a complete list of capabilities and associated definitions. These capabilities were then grouped according to their primary desired purpose – or "Outcome" – to include the following:

- **Reduce Impact of Outages**. Measures that improve a Distribution Company's ability to rapidly detect and respond to fault conditions on the network to reduce the duration and number of customers affected by an outage.
- **Optimize Demand**. Measures that are intended to encourage customer engagement in peak load reduction and enable load to be more fully utilized as a resource for distribution system planning and operations.

[9] The American Reinvestment and Recovery Act established grant funding of $3.4 billion for select Smart Grid projects.

Figure 3-1: Massachusetts Grid Modernization Taxonomy

Outcomes	Capabilities/Activities*	Network Systems Enablers
Reduce Impact of Outages	Fault Detection, Isolation and Restoration	• Communications • SCADA / Distribution Management System • Outage Management System • Geospatial Information System
	Automated Feeder Reconfiguration	
	Intentional Islanding	
Optimize Demand	Volt/VAR Control, Conservation Voltage Reduction	• Communications • SCADA / Distribution Management System • Metering System • Meter Data Management System • Billing System
	Load Control	
	Home Area Network Capability	
	Advanced Load Forecasting	
	Time Varying Rates	
Integrate Distributed Resources	Voltage Regulation	• Communications • SCADA / Distribution Management System
	Load Leveling and Shifting	
	Remote Connect / Disconnect	
Workforce and Asset Management	Mobile Workforce Management	• Communications • Outage Management System • Geospatial Information System
	Mobile Geospatial Information System	
	Remote Monitoring and Diagnostics	
Prevent Outages	System Hardening	
	Aging Infrastructure Replacement	
	Vegetation Management	

** Note: Capabilities/Activities are connected here to their primary outcomes. Some Capabilities/Activities can also help facilitate other outcomes (see definitions).*

- **Integrate Distributed Resources** Measures that enable a Distribution Company to safely and efficiently interconnect distributed energy resources – including distributed generation (both continuously operating or variable output) and storage technology - to its electric grid These measures may also support utilization of such resources for system planning and operations, including system hardening, and may also facilitate the deferral of transmission or distribution capital investments. [10,11]

Workforce and Asset Management. Measures that improve a Distribution Company's ability to monitor the location, performance, and utilization of equipment and crews across its network. In addition to the grid modernization capabilities and associated outcomes referenced above, the Working Group also recognized the Department's desire to consider measures that could improve service reliability during storm events. These measures include a variety of activities, such as vegetation management and system hardening, which have long been utilized by Distribution Companies and are not unique to grid modernization initiatives. Accordingly, the Working Group created a separate outcome – "Prevent Outages" - to ensure the Department fully considers the range of Distribution Company investments that can support the goals and objectives included in its NOI:

- **Prevent Outages**. Measures that improve a Distribution Company's ability to withstand severe weather events or other natural disturbances while maintaining service to customers.

The Working Group also sought to capture the core systems (e.g., metering) and enterprise software applications (e.g., outage management system) that underpin Distribution Company operations and support implementation of the various grid modernization capabilities. For example, a distribution company may require both Supervisory Control and Data Acquisition (SCADA) capabilities and a Distribution Management System (DMS) to implement automated feeder reconfiguration. These systems and software applications – collectively referred to as "Network System Enablers" – are included in the taxonomy alongside the relevant grid modernization capabilities.

Finally, whereas the NOI draws a distinction between "Grid-Facing Technologies" (e.g., those technologies that improve network performance) and "Customer-Facing Technologies" (e.g., those technologies that enable greater customer engagement), the Working Group sought to capture both categories within the taxonomy. This approach reflects the Working Group's assessment that many of the Department's goals and opportunities could best be pursued through a combination of grid-facing and customer-facing technologies. In fact, grid modernization investments around the country often feature the integration of grid-facing and customer-facing technologies to achieve desired outcomes.

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[10] The Steering Committee notes that the DPU has consistently found that "[s]afety and reliability are of paramount importance to the Department. Although the advancement of DG in the Commonwealth is a very important goal, it must not jeopardize the reliability of the electric distribution system, the distribution equipment itself, or the safety of customers and those who maintain the system." (D.P.U. 11-75-E at 34). Consistent with this core responsibility, grid modernization investments must support the Distribution Companies' obligation to provide reliable and safe service. Grid modernization measures may enable a Distribution Company to safely and reliably integrate greater quantities of distributed resources Pursuant to a Department Order in D.P.U. 11-75, the Distribution Companies, the Department of Energy Resources and numerous distributed generation developers convened the Distributed Generation Working Group ("DGWG") to review and, where appropriate, recommend changes to the Standards for the Interconnection of Distributed Generation ("DG Tariff"). The DGWG filed its recommendations in a report on September 14, 2012 and on May 1, 2013 the DPU approved new DG Interconnection tariffs for the distribution companies. The DGWG continues to work on transition items set out in the Order and in the DG Report.

[11] AGO Footnote: Not all distributed resources can be assumed to provide a benefit to the distribution system, and some may actually add costs to the distribution system.

3.2. Definitions—Outcomes & Capabilities/Activities

Outcome 1: Reduce Impact of Outages

- Fault Detection, Isolation, Restoration (FDIR)
- Automated Feeder Reconfiguration
- Intentional Islanding

Fault Detection, Isolation, Restoration (FDIR)

FDIR is a collective term for the process of identifying the location of a fault condition on the system through the use of current and voltage monitoring devices; isolating the fault between two devices adjacent to the fault (e.g., opening two switches on either side of the fault); and, restoring service to the customers in the unaffected areas (i.e., not in the isolated section where the fault occurred). Next generation systems may use pre-programmed restoration scenarios that rapidly respond to equipment load ratings and real-time system load measurements. Such advanced applications require a robust, scalable two-way communications network. Although FDIR is sometimes referred to as a "self-healing grid," it is important to note that the fault is not corrected until Distribution Company workers correct the cause of the fault – such as a downed wire - and return the affected section back into service.

Automated Feeder Reconfiguration

Automated feeder reconfiguration refers to the constant monitoring of the status of the distribution system (e.g. voltage and load conditions) and the ability of the system to respond by using alternate sources of supply to avoid an overload situation. Some FDIR systems also support automated feeder reconfiguration capability that enables restoration of service to the greatest number of customers possible through real time load monitoring.

Intentional Islanding (microgrid control)

An island condition is a situation where one or more generators are feeding an isolated section of the Distribution Company's system. Intentional islanding control technology is used to isolate a specified section of the Distribution Company system from the rest of the grid (and its supply sources) such that the section is fed solely from local generation. This technology is also used to promote seamless reconnection of the islanded section to the larger grid. An unintentional island condition - in which a generator feeds into a fault on the grid - can pose a significant safety risk to Distribution Company employees and the general public because a line may remain energized without the Distribution Company's knowledge.

Outcome 2: Optimize Demand

- Integrated Volt/VAR Control, Conservation Voltage Reduction
- Distribution Company /3rd party Demand Response Programs (load control)

- Home Area Network Communications Capability
- Advanced Load Forecasting
- Time Varying Rates

<u>Integrated Volt/VAR Control</u>

Volt/VAR management is the term for technology that measures voltage and power factor on the distribution system and corrects imbalances to minimize power quality disturbances and limit line losses of the system. Next generation systems may include centralized processing with the ability to perform feeder-specific, substation-specific and area/region optimization. Future applications may also incorporate distributed solar photovoltaic (PV) cells and other resources through the use of controllable inverters for VAR support.

<u>Conservation Voltage Reduction</u>

Conservation voltage reduction refers to the active management of distribution voltage within a tight bandwidth to reduce energy consumptions and peak demand. Next generation systems may include centralized processing with the ability to perform feeder-specific, substation-specific and area/region optimization.

<u>Distribution Company /3rd party Demand Response Programs (load control)</u>

A load control demand response program is one where a signal is sent to a customer device (e.g., programmable controllable thermostats, water heaters, air conditioners, Electric Vehicle Supply Equipment (EVSE)) instructing that device to reduce electricity consumption. A two-way signal allows the sender of the signal to confirm whether the device has responded or the customer has decided to over-ride the signal. A load control program may be implemented by a Distribution Company or third party.

<u>Home Area Network Communications Capability</u>

A home area network (HAN) is a network of energy management devices, digital consumer electronics, signal-controlled or enabled appliances, and applications within a home environment that is on the customer side of the electric meter[12]. A HAN provides customers with access to usage data in more frequent time increments than once-monthly billing information. Retail pricing information may also be communicated to customers through a HAN. For example, a customer may program controls in the home to increase the set-point on the air conditioner in response to a critical peak signal sent from the Distribution Company. In order to connect a HAN to the customer's meter, the meter must have a HAN communication module installed and activated or be otherwise able to communicate with the HAN. A

[12] As defined by the National Institute of Standards and Technology NIST Priority Action Plan 2 Guidelines for Assessing Wireless Standards for Smart Grid Applications (http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/PAP02Objective3/NIST_PAP2_Guidelines_for_Assessing_Wireless_Standards_for_Smart_Grid_Applications_1.0.pdf)

HAN may also be installed by a customer for a variety of energy management purposes without requiring a connection to the meter.

Advanced Load Forecasting

Advanced load forecasting is the process of making more accurate and discrete predictions about future system loads based on customer usage data. Improved forecasts enable operators to better schedule and dispatch generation. Such forecasting may also include distributed generation and other resources, including demand response and electric vehicles.

Time Varying Rates

Time varying rates (TVR) changes the price customers pay based on time of day such that the rate is higher during periods of peak demand. At the most extreme, customers can pay a different price every hour based on wholesale market prices. In more traditional pricing structures, customers pay a different rate for a given number of hours every weekday, coincident with the time of system peak demand. Another form of time varying rates is a critical peak price or peak-time rebate that is typically implemented for a limited number of critical peak events when the system is constrained due to very high demand. A critical peak pricing program entails a higher price during critical peak periods, whereas a peak-time rebate provides customers with a credit or rebate for reducing usage during the same critical peak periods.

Outcome 3: Integrate Distributed Resources

- Voltage Regulation
- Load leveling and shifting (Intentional 2-way power flow)
- Remote Distributed Generation Connect/Disconnect & Monitor

Voltage Regulation

Advanced voltage regulation technologies may be used by Distribution Companies to manage fluctuations in voltage caused by large amounts of distributed generation relative to the amount of load in a given section of the Distribution Company system.

Load Leveling and Shifting (Intentional 2-way power flow)

Load leveling and shifting alters the pattern of demand to more closely match output from non-dispatchable, intermittent distributed resources such as solar PV. This technology may help mitigate reverse power flows and localized disturbances typically associated with high levels of intermittent distributed generation. Advanced applications may enable Distribution Companies to use distributed resources for system balancing operations. Such applications may include: on-site battery storage for active energy support; and voltage “ride through” capabilities that enable distributed generators to operate uninterrupted though grid disturbances.[13]

Remote Distributed Generation Connect/Disconnect & Monitor

Remote disconnect is technology that enables a Distribution Company to use automation to remotely disconnect a distributed generation facility from the distribution system to protect safety or maintain service to other customers.

Outcome 4: Workforce and Asset Management

- Mobile Workforce Management Systems
- Mobile GIS Platforms
- Remote Monitoring & Diagnostics (equipment and system conditions)

Mobile Workforce Management Systems

Mobile workforce management systems provide Distribution Company field technicians with mobile access to asset records and other critical information in an effort to support timely and accurate assessments and services. These systems may also provide data useful to supervisors to plan, dispatch and monitor field services across a distribution company’s service area.

Mobile Geographic Information Systems Platforms

A Geospatial Information System (GIS) is the Distribution Company’s system of record for the as-built transmission and distribution network, providing a spatial view of assets and connectivity. Mobile GIS platforms allow Distribution Company technicians to download selected portions of the database to a laptop or other personal device for use in the field.

Remote Monitoring & Diagnostics (equipment conditions)

Remote monitoring and diagnostics enable Distribution Companies to collect more frequent data on the status of system equipment (e.g., oil samples from substation transformers). A Distribution Company may use these data to identify concerns (e.g., abnormal equipment performance), optimize day-to-day asset utilization and support condition-based maintenance programs.

Remote Monitoring & Diagnostics (system conditions)

Remote monitoring and diagnostics for system conditions consists of data collected via SCADA systems, to include voltage, loading, current, power factor and frequency. A Distribution Company may use these

[13] Other options to accommodate the use of DG in support of the electric distribution system, including “equipment upgrades associated with running customer owned generation that is compatible with the connected utility distribution system,” are described in “Guidance Document for Customer Owned Distributed Generation Applications: A Working Draft,” prepared by KEMA Consulting, Inc. on June 26, 2009, based on Distributed Energy Planning Workshops commissioned by the Massachusetts DG Collaborative in 2006.

data to feed planning models, support advanced load forecasting and enable analytics that can improve and optimize system planning and operations.

Outcome 5: Prevent Outages

- System Hardening
    - Elevated Substations
    - Equipment Hardening
    - Distributed Generation/Storage
- Aging Infrastructure Replacement
- Vegetation Management

<u>System Hardening</u>

System hardening refers to measures that are intended to make a Distribution Company's assets better able to withstand a major storm or other catastrophic event. System hardening measures may include: elevated substations; equipment hardening; and distributed generation/storage.

- <u>Elevated substations</u> are raised above ground-level to mitigate the risk of flooding during storm surges and other weather-related events. Such flooding can damage Distribution Company equipment and contribute to prolonged outages. Alternative approaches include relocating substations to less flood-prone areas or installing protective measures, such as pumps and levees.
- <u>Equipment hardening</u> refers to the replacement of existing Distribution Company infrastructure with equipment manufactured to more robust design standards and better able to withstand wind, water, ice and other elements. Examples include: installation of higher class poles and submersible equipment; installation of equipment with enhanced lightening protection; and replacement of bare wire with covered wire.
- <u>Distributed generation</u> includes generators (continuously operating or variable output) located on a Distribution Company's system at or close to a customer load, Storage refers to a set of technologies capable of storing previously generated electric energy and releasing that energy at a later time. Distributed generation and storage can harden the grid when integrated and/or combined appropriately, for instance by providing uninterrupted power to critical facilities and supporting expedited power restoration during unplanned outages.

<u>Aging Infrastructure Replacement</u>

Replacement of infrastructure that is prone to failure due to age with equipment that meets current design specifications. An example is the replacement of paper insulated lead cable with Ethyl-Propylene Rubber (EPR) insulated cable.

Vegetation Management

Vegetation management entails a series of Distribution Company -sponsored measures to reduce the frequency of faults caused by trees and other vegetation coming into contact with overhead power lines. Vegetation management may include: tree pruning and removal; vegetation control around poles, substations, and other electric facilities; manual, mechanical, or chemical control of vegetation along rights-of-way; tree inventories; and other related activities.

3.3. Network Systems Enablers

- Distribution Management System (DMS)/SCADA
- Outage Management System (OMS)
- Geospatial Information System (GIS)
- Billing System
- Metering System
- Meter Data Management System (MDMS)
- Communication Systems (Fiber, Microwave, Radio, etc.)

Distribution Management System (DMS)/SCADA

A DMS is a computer system used by a Distribution Company to receive data from devices deployed at various locations on the network that are equipped with supervisory control and data acquisition (SCADA) technology to provide operators with a real-time picture of the status of the distribution system. Using the DMS, operators can control devices to isolate faults and restore unaffected sections of the system. Advanced capabilities of the DMS enable automatic operations in response to current conditions (e.g., fault conditions, volt/VAR optimization and feeder reconfiguration in response to load). Although it is often assumed that a DMS will be deployed on a system-wide basis, it can also work at a substation or feeder level when appropriate.

Outage Management System (OMS)

An OMS is a computer system used by a Distribution Company to collect data on the location of outages on the system and the number of customers affected. Customer calls reporting loss of service are represented in the OMS which then uses software-based rules to identify the likely source location for the outage. In larger scale events with multiple simultaneous outages, the OMS is used by the Distribution Company to prioritize restoration efforts by focusing on outages affecting the greatest number of customers. As power is restored, the OMS is updated based on field reports ensuring an accurate representation of remaining problems. A Distribution Company's OMS may be integrated with a DMS and/or metering system.

Geospatial Information System (GIS)

A GIS is a computer system that provides a graphical representation of the distribution system. The GIS system may include the asset location of major Distribution Company equipment such as substations, switches, transformers and poles. Detailed asset information (manufacturer, installation date, size, etc.) is also stored along with the location data. The GIS is typically the single source or repository of asset information that feeds system planning models, system operations models, outage management models and work-order/financial systems. Advanced features may include system mapping and design modules. A Distribution Company may also integrate its GIS and OMS systems to allow for reported outages to be mapped on the GIS system for an accurate location of the device (e.g. fuse or switch) that the OMS calculates as most likely to be at the source of the outage.

Billing System

A Distribution Company's billing system creates a customer bill by applying a customer's electricity usage for a given period to the customer's rate structure. The billing system typically works together with a customer information system as the system of record documenting address, contact information, payment history and special status (e.g., life support customer).

Metering System

The Distribution Company's metering system is the collective term for the customer meters that measure electricity usage and the communications method used to transmit usage data back to a meter data management system. Electricity meters measure usage for a given period of time (e.g. as frequently as every 5 minutes or infrequently as monthly) and in some cases measure peak demand for a period. The communications infrastructure may range from manual reading on a hand-held device downloaded at a central location (Manual Meter Reading) to two-way cellular or radio signals sent every 15 minutes that will support advanced features such as dynamic rate structures, demand response programs and outage management (Advanced Metering Infrastructure).[14] A Distribution Company may integrate its metering system and OMS to allow for outage data to be recorded in the OMS based on the status of each customer's meter rather than as a result of customer phone calls.

Meter Data Management System (MDMS)

An MDMS is a computer system that takes raw usage data and processes it into a form that can be used for billing. For instance, an MDMS can take hourly usage data for a month and categorize the hours into on and off-peak periods that can be sent to the billing system to create a time of use bill. In some instances, a Distribution Company's billing system is capable of serving as its MDMS as well. An MDMS

[14] Advanced Meter Reading (AMR): "AMR technology allows utilities to read customer meters via short-range radio-frequency signals. These systems typically capture meter readings from the street using specially equipped vehicles." Advanced Metering Infrastructure (AMI): "AMI systems combine meters with two-way communication capabilities. These systems typically are capable of recording near-real-time data on power consumption and reporting that consumption to the utility at frequencies of an hour or less". MIT, *Future of Electric Grid Report* (2011), pg. 133).

also facilitates the delivery of advanced metering features, such as dynamic rates, demand response programs and outage management.

Communications Systems (Fiber, Microwave, Radio, etc.)

Communication systems are used in many Distribution Company operations. Voice communication systems (e.g., radio or cellular) enable the work force to communicate on a real-time basis. Data communication is used for collecting information on distribution system status from SCADA devices and metering systems to transmit usage data from meters to an MDMS. Data communication is also used as a means to remotely control devices in the field. Distribution companies must consider a range of requirements when evaluating communications system investments, to include bandwidth, service quality, latency, scalability and interoperability with existing systems.

4. Background Information and Joint Fact Finding Roadmap

Note: All the presentations and other documents referenced in this chapter can be found (http://magrid.raabassociates.org/events.asp?type=eid&event=100)

4.1. Grid-Facing

The Grid-Facing Committee asked the Distribution Companies two sets of questions regarding the status of the existing grid-facing infrastructure. The purpose of these questions was to provide an indication as the extent to which the Distribution Companies have adopted grid modernization capabilities and network system enablers (see Figure 3.1)

The first set of questions was intended to get descriptions; installation dates; the levels of deployment of various technologies; and additional characteristics of the various network system enablers. The second set of questions was focused on the Distribution Companies' current capabilities for integrating distributed generation onto their systems; including information regarding the measurement/estimation of minimum load, equipment to readily integrate distributed generation resources, and additional relevant data. See Grid Facing Utility Data Responses 1 for the questions asked, and the Distribution Companies responses to them

The responses to the first set of questions are summarized below in Table 4-1, Table 4-2 and Table 4-3. Table 4-1 provides an overview of the substations, feeders and capacitors that are currently installed on the utility systems. For each Distribution Company, and for each technology type, the table presents the total number, the number of automated technologies, and the percent of the total that is automated. This table also provides some definitions of the different technology categories.

Table 4-2 provides more details, including the types of network system capabilities (e.g., fault detection, integrated volt/VAR control, remote monitoring) that are located on each Distribution Company system. This includes information on the level of the system at which the capabilities are located, including transmission system level, distribution system level, substation level or neither.

Table 4-3 provides additional details for the network system enablers. This includes when they were installed, status of recent upgrades, and future plans for upgrades.

Based on the responses to the first set of grid facing questions, the Distribution Companies were asked to respond to a second set of grid-facing questions. The first question of this second set asked for the percentage of substations, feeders and line sections where each Distribution Company was able to directly measure minimum load. The second question asked each Distribution Company to provide the number of substation transformers and voltage regulators capable of reverse power flow. Finally, the third question gave each Distribution Company the opportunity to provide any additional data or descriptions that would further explain their deployment of modern grid technologies.

The Distribution Companies' responses to the second set of grid-facing questions are summarized in the tables below. Table 4-4 shows the percentage of each utility's system with the ability to measure minimum load. Table 4-5 shows the percentage of each utility's systems that are capable of reverse power flow.

Note that the Distribution Companies' responses to these questions include some important notes with more detail on the information in these tables. In addition, the responses include additional information and explanation about the deployment of technologies on the distribution system, beyond what could be summarized here. For the complete responses from the Distribution Companies see Grid Facing Utility Data Responses 2.

Table 4-1: Percentage of Systems that are Automated

	Substations1			Feeders2			Capacitors3				
	Total	Automated	Percent	Total	Automated	Percent	Total	SCADA Control	Percent	Automated Response	Percent
NSTAR	200	120	60%	1579	995	63%	830	640	77%	95	11%
WMECo	28	10	36%	233	134	58%	250	62	25%	77	31%
National Grid	258	138	53%	1028	567	55%	2500	0	0%	1800	72%
Unitil	11	4	36%	36	14	39%	135	0	0%	40	30%

Category Definitions

Substation

Substation automation is defined as the full SCADA integration (status, control and analog data) of the substation for all major equipment (power transformers, substation capacitors and breakers/reclosers). This may or may not include the power transformer LTC (Load Tap Changer) and/or individual phase regulators for distribution feeders.

In some cases partially automated substations (portion of a substation is fully automated without all distribution feeders being fully automated) have been included in the count (a very small percentage of feeders are in this category). "Full" automation does not typically include feeder phase regulators but does include LTC automation for new installations.

Feeders

Feeder automation is defined as the full SCADA integration (status, control and analog data) of the feeder breaker/recloser within the substation fence and/or the SCADA control of automatic sectionalizing devices outside the substation fence on the distribution feeder. Additionally non-communication enabled automated loop sectionalizing schemes and/or preferred/alternate schemes have been included as well as more advanced multi-switch/multi-feeder communicating FDIR schemes. These figures include both overhead and underground feeders

Capacitors

Capacitor counts included in this table are line banks only, not substation banks.

SCADA control is defined as the ability to send a signal to remotely operate the bank and may or may not include status of the bank.

Automated response is defined as the presence of a local control capable of operating the bank programmatically based on time, day, date, temperature and/or power quantity values (voltage, current, KW flow, KVAR flow, etc.).

Table 4-2: Type and Location of Network System Enablers

NSTAR		
System Location	Notes	
Fault Detection, Isolation, Restoration (FDIR)	Distribution system and substations	80 auto reconfiguration loops, with 100 additional planned for 2013
Automated Feeder Reconfiguration	Distribution system and substations	FDIR devices continuously monitor system, alerting operators of loading concerns.
Integrated Volt/VAR Control, Conservation Voltage Reduction	Transmission, distribution, substations	830 Capacitor bank,of which 640 are controllable remotely. No CVR.
Remote Monitoring & Diagnostics (equipment conditions)	Transmission, distribution, substations	All major equipment is remotely monitored via SCADA i.e. Substation transformers, remote controlled switches, communications, etc..
Remote Monitoring & Diagnostics (system conditions)	Transmission, distribution, substations	All remote controlled reclosers and ASUs monitor the system providing voltage, current and power factor.

WMECO		
System Location	Notes	
Fault Detection, Isolation, Restoration (FDIR)	Distribution system	120 recloser loop schemes on its system. All loop schemes operate automatically in response to loss of source voltage.
Automated Feeder Reconfiguration	None	
Integrated Volt/VAR Control, Conservation Voltage Reduction	Distribution system and substations	Manage voltage within a +/- 5% bandwidth, no CVR
Remote Monitoring & Diagnostics (equipment conditions)	Substation	Alarms alert operators for various abnormal conditions. No capability to remotely sense specific equipment conditions (e.g. oil levels) or diagnose problems.
Remote Monitoring & Diagnostics (system conditions)	Distribution system and substations	DSCADA for remote monitoring and diagnostics of system conditions.

Unitil		
System Location	Notes	
Fault Detection, Isolation, Restoration (FDIR)	Distribution system	One circuit currently has FDIR recloser combination
Automated Feeder Reconfiguration	None	
Integrated Volt/VAR Control, Conservation Voltage Reduction	Distribution system and substations	Manage localized circuit level power factor and voltage through the use of capacitor banks that are automatically controlled based on system condition or time of day.
Remote Monitoring & Diagnostics (equipment conditions)	None	
Remote Monitoring & Diagnostics (system conditions)	Distribution system and substations	SCADA is installed in 4 of 11 substations. This includes remote monitoring on 4 capacitor banks, approximately 45 breakers/reclosers, and 6 transformers.

National Grid		
System Location	Notes	
Fault Detection, Isolation, Restoration (FDIR)	Distribution system	Approximately 100 non-communicating or communicating loop sectionalizing schemes and/or preferred/alternative schemes Small rollout of Advanced Distribution Automation (multi-switch/multi- feeder communicating system) as part of SG pilot
Automated Feeder Reconfiguration	None	
Integrated Volt/VAR Control, Conservation Voltage Reduction	Distribution system	Advanced Local Volt/Var Control: Small rollout as part of SG pilot 2.5/5% voltage reduction on 75% of feeders per NE-ISO operating procedures
Remote Monitoring & Diagnostics (equipment conditions)	Transmission, distribution, substations	A small subset of large power transformers have remote condition monitoring via SCADA, additionally SCADA alarms alert operators of various abnormal conditions on a wider range of distribution and transmission equipment. A small rollout of devices as part of the SG pilot will provide equipment monitoring on all new devices.
Remote Monitoring & Diagnostics (system conditions)	Transmission, distribution, substations	SCADA for remote monitoring and diagnostics of system conditions within the substation fence. Also remote controlled reclosers monitor the system providing voltage, current and power factor. A small rollout of new equipment as part of the SG pilot will provide near real time monitoring of system conditions at several locations on the pilot feeders.

Table 4-3: Details of Network System Enablers

Type	When Installed	Most Recent Upgrade	Future Plans	Notes
NSTAR				
Distribution Management System (DMS)/SCADA				
GE SCADA/EMS: Trans, Sub-trans, North Distribution	1994	2007	Migrate and implement auto-restoration schemes	1,100+ supervisory, and 60,000+ analog & digital points
GE Powerlink Advantage: South Distribution	2005	2011		750+ supervisory, and 40,000 analog & digital points.
CGI PragmaLine v2.03	2000	Replaced		
GATOR	2003		Planned replacement 2013-2014	
Editor: Custom ESRI	North: 1990s, South: 2004	Upgrade in progress		
Viewer: ESRI ArcMap with customization	2004	Upgrade in progress		
Transmission Editor: ArcFM	2008	Upgrade in progress		
GIS-OMS Integration				
GATOR-GUI	2003 (within OMS upgrade)	GIS upgrade in progress	OMS Replacement 2013-2014	
Billing System				
	1991	Continuous		
Metering System				
Premierplus4	?	Replaced		
FCS (Field Collection System)	2012	Underway		
Route Smart ArcGIS	2007	2011		
MV90 (Interval Meter Collection)	2006	2009	Upgrade in 2013	for 7000 TOU meters via modem and cellular networks
Lodestar	2011			
OMS-AMR/AMI Integration				
	N/A	N/A		
Communication Systems				
Various systems	2008-2010			
WMECO				
Siemens Spectrum Power TG	2002	currently upgrading		2400+ devices, 280,000+ analog & digital points.
Oracle Network Management System	2004	2007	upgrade/replacement in 2014	
Editor: GE Smallworld Editor	2002	2008		
Viewer: GE SIAS Viewer	2010			
Transmission Editor	N/A	N/A	Integration into Smallworld editor around 2013	
Viewer: ESRI SilverLight Viewer - custom	2012			

Type	When Installed	Most Recent Upgrade	Future Plans	Notes
GIS-OMS Integration				
Smallworld	2004	2008	replacement in 2014	
Billing System				
C2 Application	2008	Continuous		
Metering System				
Fieldnet	1990s	2012	Upgrade in 2014	
Prime Read (Interval Meter Collection)	2008		Move all to MV90 and retire application	
ION Revenue	2005		Move all to MV90 and retire application	
Lodestar MDM	2013			
SerViewCom	?	2010	Move all to MV90 and retire application	
EVEE Meter Data Warehouse	2003	2012		
OMS-AMR/AMI Integration				
	N/A	N/A		
Communication Systems				
Fiber	2005-2013			
Microwave	2005-2013		Some will be replaced by fiber, where appropriate	
Mobile Radio	2005-2008			
DSCADA Radios	2012-2013			
National Grid				
None	N/A	N/A	Planned OMS and EMS SCADA interface after OMS installation in fall 2013 to support potential future DMS	
Outage Management System (OMS)				
PowerOn	2006		PowerOn to be replaced with ABB OMS as part of EMS upgrade during fall of 2013	
GE Smallworld	2004	2011	Currently using latest version (V4.2), no upgrade plans for a least three years. Transmission is currently upgrading to V4.2 from V4.0	Current GIS is integrated with OMS and WMS
GIS-OMS Integration				
Fully Integrated - GE Smallworld/PowerOn	2006		PowerOn to be replaced with ABB OMS as part of EMS upgrade during fall of 2013	
Billing System				
Customer Service System (CSS)	2008		Integration of SG Pilot meter data	
Metering System				
Solid State (22%)	around 2000	2012	none planned, but Smart Grid Pilot underway	297 thousand meters. 92% of all National Grid meters read via Drive-by AMR

Type	When Installed	Most Recent Upgrade	Future Plans	Notes
Electromechanical Meters (78%)	around 2000	2012	none planned, but Smart Grid Pilot underway	1.05 million meters. 92% of all National Grid meters read via Drive-by AMR
Itron - Field Collection System	2003	2012		Based on AMR drive by and manual walking route collection, meter data stored in Energy Resource System (ERS)
Itron - IEE MDMS	2013			This AMI system will be used for Worcester Smart Grid Pilot only ~ 15,000 meters
OMS-AMR/AMI Integration				
Customer Service System (CSS)	2008		CSS feeds customer outage information (Calls) into OMS for analysis	In house developed system
Communication Systems				
Private fiber optic	N/A	N/A		Used for voice, protection, network and SCADA
Private microwave	Late 1980's, 1996	Present	Analog system expected to be replaced by 2015	Used for voice, protection, network and SCADA, System spans both analog and digital systems
Land mobile radio system	Various	~2010	System updated over last four years	Used for voice
Unitil				
Areva E-terracontrol	Early 2000's		replacement with efacec ACS SCADA system in use elsewhere	
ABB Network Manager OMS	2010			
ESRI with Schneider Electric ArcFM	Early 2000's	Several		
GIS-OMS Integration				
Fully-integrated	Integrated in 2010		routine software upgrades	
Billing System				
HTE-based CIS	1990's		Replacement (over 2 years) beginning 2013	
Metering System				
Landis and Gyr TS2 AMI system	2006			
	?		Purchase of MDM with integration of new CIS system	
OMS-AMR/AMI Integration				
	integration after OMS rollout	2011 AMI system integration		
SCADA: Telephone	Installed at new sites			
AMI: Powerline carrier tech	2006			
Unitil Offices: T1				
Unitil Offices: Fiber				

Table 4-4: Percentage of Systems With the Ability to Measure Minimum Load

		Substations	Feeders	Line Sections
National Grid		52%	50%	27%
NSTAR	North 115/14kV Stations	100%	100%	-
	North 4kV Stations	80%	84%	-
	South 115/23kV and 115/13.2kV Stations	100%	100%	
	South 4kV Stations	5%	5%	-
	North and South 15kv Line Sectionalizing Devices	-	-	93%
	North and South 4kv Line Sectionalizing Devices	-	-	100%
Unitil		30%	37%	0%
WMECO		70%	36%	21%

Table 4-5: Percentage of Systems Capable of Reverse Power Flow

	Substation Transformers	Substation Regulation	Feeder Regulation
National Grid	Reverse power flow issues regarding DG installation can potentially be addressed on an on-going basis as technologies and operational knowledge matures.	No count available. Percentage is relatively low. New controls have bidirectional capability.	No count available. Percentage is relatively low. New controls have bidirectional capability.
NSTAR	Systems designed for forward power flow. Little experience to date with reverse flow.	Roughly 50%.	Roughly 50%.
Unitil	No substation transformers currently designed for reverse power flow.	No count available. Percentage is relatively low. New controls have bidirectional capability.	No count available. Percentage is relatively low. New controls have bidirectional capability.
WMECO	Systems designed for forward power flow. Little experience to date with reverse flow.	Roughly 50%.	Roughly 50%.

4.2. Time-Varying Rates

Time varying rates (TVR aka dynamic pricing) issues and experience in the U.S. and abroad were presented by the Brattle Group at the Kick-Off Summit (See Brattle TVR & Meters 11.14.12). The Customer-Facing Subcommittee then heard detailed presentations regarding the smart grid pilots from NSTAR, National Grid, and UNITIL at its first meeting (See National Grid, NSTAR, & Unitil Smart Grid Pilot 1.9.13), and the Steering Committee heard an updated presentation on NSTAR's pilot at its 6th meeting (See NSTAR Pilot Update 5.22.13). At the second Customer-Facing Subcommittee meeting, the Regulatory Assistance Project presented additional information on experience and issues in the U.S. and abroad on TVR, and the Attorney General's consultant presented both the principles developed by NASUCA et al on consumer protections related to TVR and AMI as well as additional recent experience across the U.S. on TVR and AMI (See RAP TVR and AG TVR presentations 2.26.13). Finally, at the 5th Steering Committee the Attorney General presented some research it had done on TVR in other restructured states (See Basic Service Memo & AG TVR Table 5.14.13). The following tables and graphs extract some of the summary tables and highlights from these presentations; however, please see the actual presentations and the meeting summaries from the meetings in which the documents were presented and discussed for the full details.

Current rates for basic service residential and small commercial customers of Massachusetts investor-owned Distribution Companies are essentially a flat rate that does not vary by time of day, day of the week, or by season. In this regard, Massachusetts is typical of other retail restructuring states where a default service is provided to residential and small commercial customers pursuant to wholesale market contracts that are intended to reduce price volatility.

Time varying rates are rates that have some variability based on when energy is consumed and generally reflect shorter term wholesale market prices—as opposed to flat rates which do not vary by time of day or season.[15] As Table 4-6 illustrates there is a continuum of ways to design rates to make them more or less reflective of the frequency of changes in price at the wholesale level. These range from time-of-use (TOU) rates that divide the day into two or three time periods with different rates that are then fixed for a season or a year, up to real-time pricing (RTP) where prices can change hourly to reflect wholesale pricing conditions. Critical peak pricing (CPP) is generally an overlay on TOU pricing that allows for prices to rise significantly at pre-announced times when costs are projected to rise significantly. Peak time rebates (PTR) is an alternative TVR approach where customers are given a rebate for reducing load generally during critical peak periods.

Table 4-6: Rate Continuum: Static to Dynamic

The Continuum: Static to Dynamic
Flat energy rates
Rates do not vary by time or wholesale market cost,and include an insurance premium to protect customers from volatility.
Tiered rates (inclining or declining blocks)
The cost per unit of electricity increases/decreases at defined consumption thresholds.
Time of use (TOU) rates (time of day, seasonal)
Divides the period (day) into time periods and provides a schedule of rates for each period (e.g. peak, off-peak, shoulder).
Critical peak pricing (CPP)
Typically an overlay on TOU pricing. During times of system stress or high cost (i.e. critical peak events), price rises to a very high level (either administratively set or market-determined) to reflect the very high but short-term cost of generating or purchasing electricity at times of shortage or peak demand. Customers are notified in advance of a CP event and the number of events per year is typically capped.
Peak-time rebate (PTR, also critical peak rebate or CPR)
Participants are paid for load reductions (relative to what they would have otherwise used) during critical peak events.
Real-time pricing (RTP) rates
Prices may change as often as hourly. Price signal is provided to the user in advance (or at the beginning) of the period to which it applies, and it reflects the actual time- and circumstance-dependent cost of generating or purchasing electricity.
Variable peak pricing (VPP) is a combination of TOU and RTP, wherein periods and the off-peak price are set, but the peak period price varies with the (day-ahead) market.

Figure 4-1 shows a depiction of the range of TVR options and how the potential reward (defined in this chart as the discount from flat rate) compares to the risk (variance in price). The chart shows that real-

[15] The definition for flat rate in Table 4-B1 also notes that flat rates include an insurance premium to hedge against volatility. We note that other TVR may also contain hedging premiums.

time pricing (RTP—generally hourly pricing) potentially has the highest reward for customers but also has the highest risk. Time-of-using pricing (TOU) on the other hand has a much lower potential reward but also a much lower risk—with CPP falling between the two. Peak-time-rebates (PT) by contrast, provide a reward (in the form of a rebate) but no real risk (since you only get a rebate when you reduce, but are not penalized if you do nothing).

Figure 4-2 presented by Brattle and by RAP, is a graph of the peak reduction and the peak to off-peak price reduction from 74 TVR pilot programs across the U.S. It illustrates two points. First, higher peak to off-peak price ratios (whether reflected in CPP or PTR) generally elicit higher responses in the form of peak reductions than lower ratios. Second, TVR associated with enabling technology that facilitates load management actions generally increases the peak reduction response. It should be noted that this table presents analysis of various pilot results which may not be indicative of wide scale deployment. According to a recent Navigant study, adoption rates of TVR in many cases remains low once scaled beyond pilot scope (see 5/22/13 Navigant presentation).

Figure 4-1: Risk-Reward Tradeoff in Time-Varying Rates

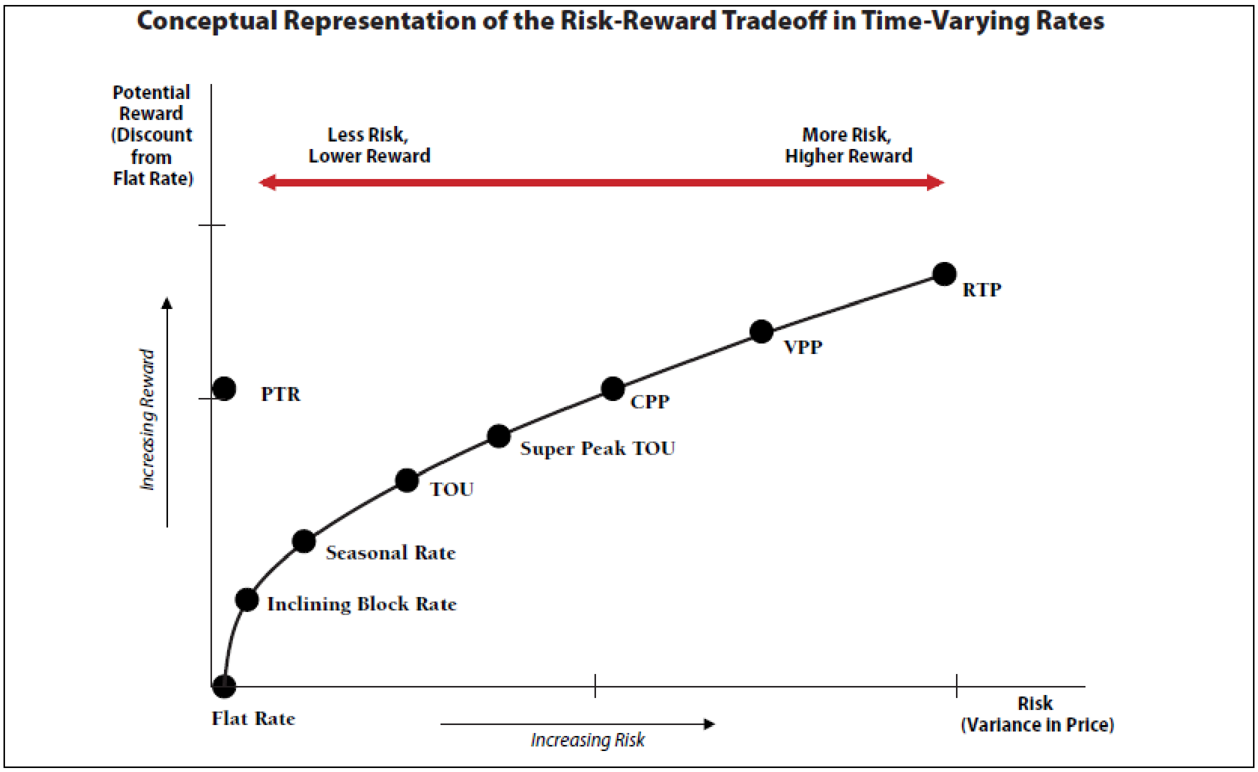
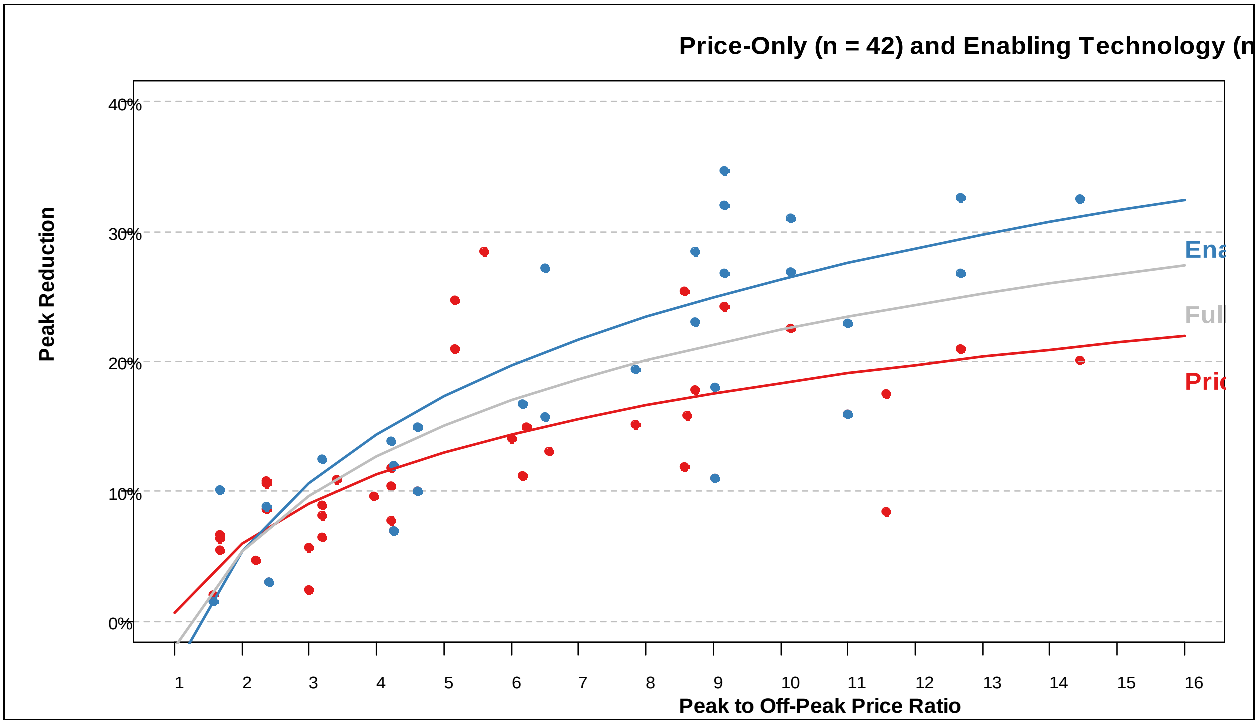


Figure 4-2: Peak Reduction Relationships to Price Ratio & Enabling Technology



The Massachusetts distribution companies are in various stages of completing their smart grid pilots[16], which are testing a range of TVR rates as well various metering and other enabling technologies.

Unitil, which already had installed an early AMI metering system for all its customers, has completed their pilot.[17] Unitil used a TOU rate with and without enhanced technology and smart thermostats. They found kw reductions with the TOU without enhanced technology of 21% on-peak and 42% during the critical peak period. The savings with the enhanced technology added increased to 35% for on-peak and 70% during the critical peak. The customer bill savings averaged 5% for the simple TOU and 7% with the enhanced technology. However, the evaluation report stated that the confidence intervals for the Enhanced Technology group tended to be wider than the other pilot groups due to technical and other data difficulties, but still showed substantial reductions. In addition, with regard to the table below, the evaluation report stated that all customers saved money in the two months when there were no critical peak events, while savings were recognizably lower and on average negative in the one month in which five Critical Peak Pricing days were declared.

[16] WMECO has approval for a settlement agreement with the AG, DOER, and the Low Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association to file with the Department a modified smart grid proposal when two conditions are met: 1) WMECO's new MDM is operational; and 2) the other Massachusetts electric Distribution Companies' Section 85 pilots have been completed, and the resulting statewide evaluation process has been concluded.

[17] Unitil's evaluation report was filed in January 2012 but there has not been any public review of the report or formal consideration of its results, including its statistical validity, by the DPU.

Table 4-7: Unitil's Smart Grid Pilot Results

	Simple TOU		Enhanced Technology		Smart Thermostat	
	Impact	%	Impact	%	Impact	%
On-Peak Period Impact	(0.42) kW	-21.2%	(0.76) kW	-34.8%	-	
Critical Peak Period Impact	(1.56) kW	-42.3%	(2.55) kW	-69.8%	(0.87) kW	-19.7%
Post Critical-Peak Impact	0.31 kW	7.6%	0.47 kW	10.2%	0.19 kW	4.0%
Critical Peak Day Energy Conservation	(5.13) kWh	-7.3%	(14.14) kWh	-19.7%	(6.07) kWh	-7.5%

Test Group	Total Jun-Aug Average Consumption			Average Customer Baseline Cost ($)	Pilot (TOU) Average Cost ($)	Average Savings ($)	Average Savings (%)
	On-Peak (kWh)	Off-Peak (kWh)	Critical Peak (kWh)				
Simple TOU	535	3008	56	$547.82	$520.20	$27.62	5.0%
Enhanced Technology	395	2453	33	$445.12	$414.82	$30.29	6.8%
Average all TOU Participants	467	2738	45	$497.87	$468.95	$28.92	5.8%

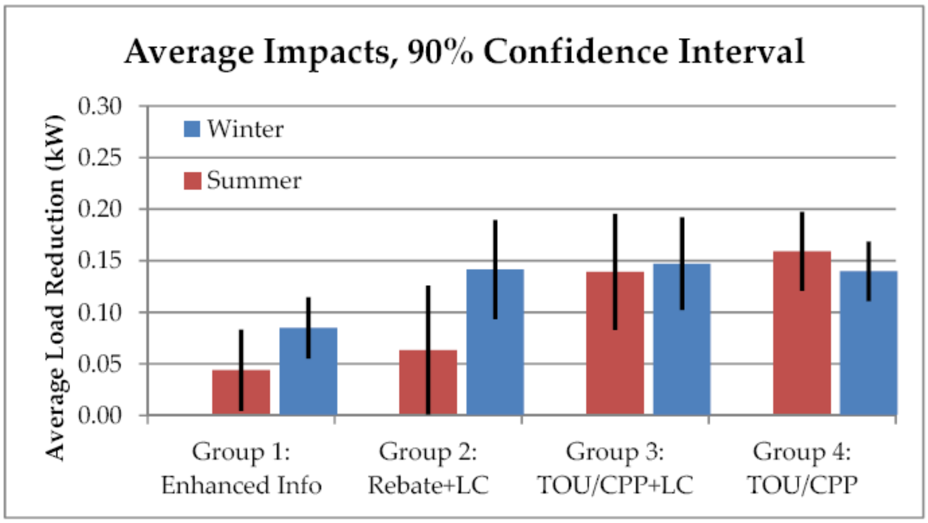
NSTAR is still in the middle of its pilot, which is scheduled to be completed at the end of 2013. NSTAR is using its pre-existing AMR meters enhanced with home area networks for its pilot. As Table 4.8 describes, NSTAR is testing 3 different TVR approaches (PTR with NSTAR control of a smart thermostat, and TOU with CPP with and without enabling technology), plus a group that will receive enhanced information but stay on their otherwise applicable rates. Figure 4.3 shows the interim peak savings during both the summer and winter for all 4 groups of participants. NSTAR presented the results of the first 9 months of its 24-month pilot from an evaluation report completed by Navigant in March 2013. The 3 TVR groups appear to have saved more kw during both the summer and winter peak periods than the enhanced information group—but there doesn't appear to be a clear winner among the two TOU options and the PTR option in terms of which performed better overall in terms of kw reduction in both the winter and summer seasons. As stated in the Preface of the preliminary results, the data from this phase of the pilot should not be relied upon until the full term of the pilot is completed and evaluated in 2014.

Figure 4-4 below provides a summary to show the customer evolution from the number of customers contacted, to installed, and finally the number currently enrolled—including the significant drop-out rate at each stage. The final evaluation and numbers on this pilot should be available in the spring of 2014.

Table 4-8: NSTAR's Smart Grid Pilot Customer Test Groups

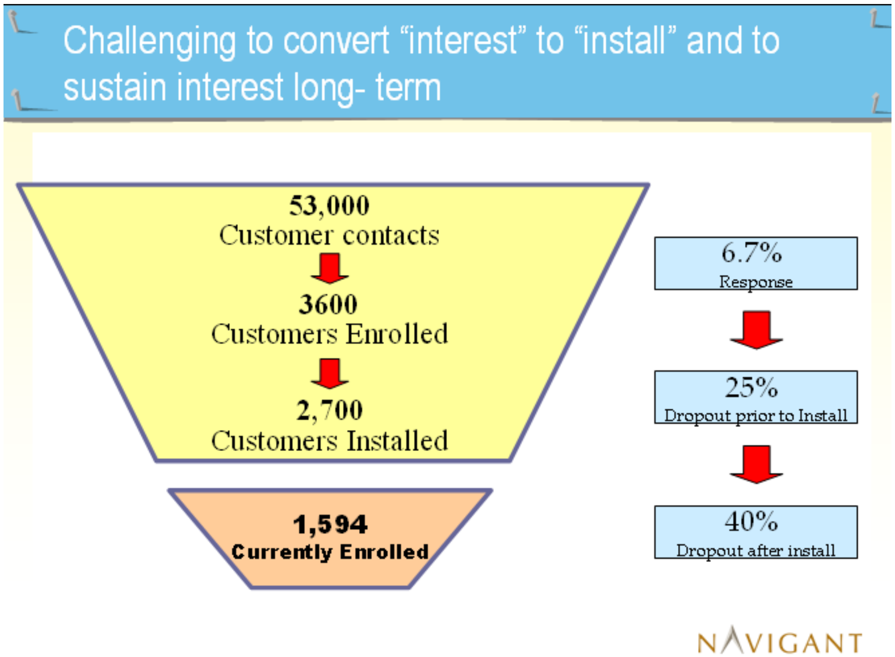
	Test Group	Description of Test Group	AC Load Control	Number of Participants
1	Enhanced Information	Access to information on energy consumption only; standard rate		878
2	Peak Time Rebate	$5 rebate for automated participation in "critical peak" events via NSTAR control of a smart thermostat; standard rate	✓	323
3	Time-of-Use (TOU) Rate plus Critical Peak Pricing (CPP)	TOU rate with CPP; smart thermostat controlled by NSTAR during CPP events	✓	309
4		TOU rate with CPP		917
	Total			2,427

Figure 4-3: NSTAR's Average Peak Period Load Reductions (January-September 2012)



Source: Navigant analysis

Figure 4-4: Enrollment in NSTAR's Pilot Program

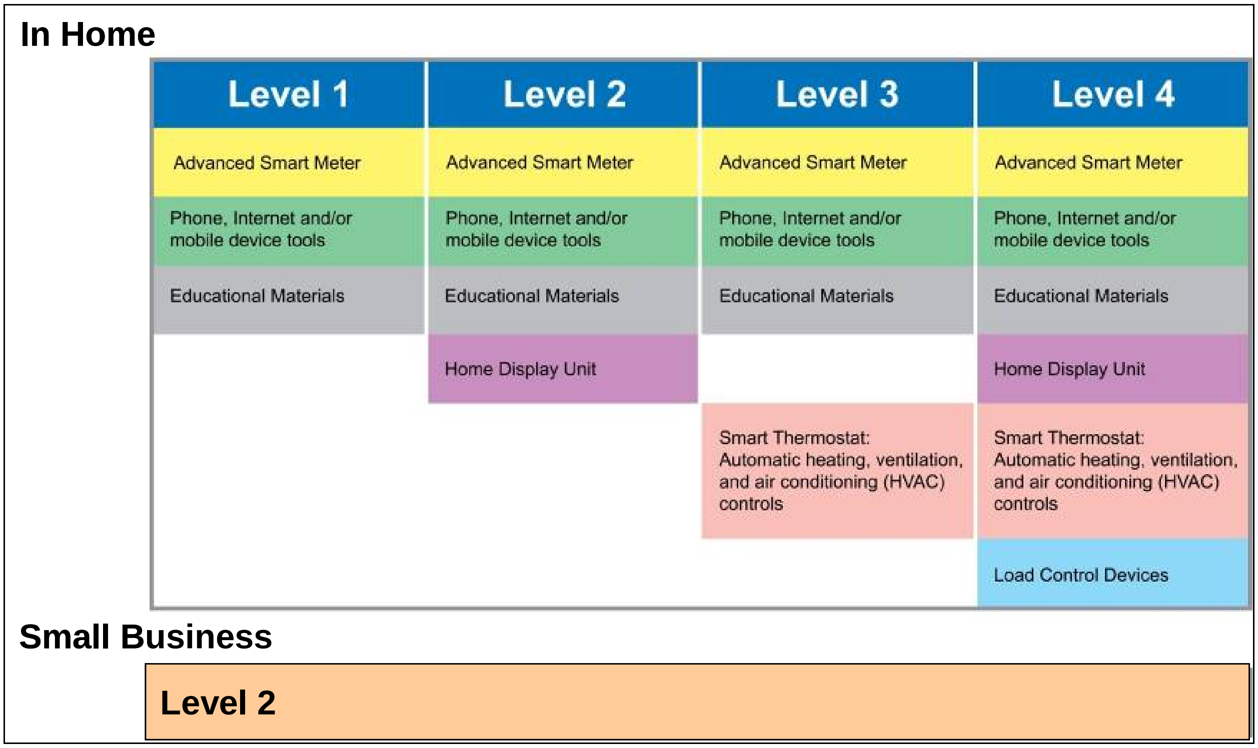


National Grid is just in the process of rolling out its smart grid pilot in Worcester, so no data is available yet except their approved design and initial experience with meter installation. Although National Grid already has AMR meters, it is planning on installing 15,000 AMI meters for the pilot participants. It will offer three different TVR options to its customers: 1) CPP for residential and small C&I; 2) PTR option also for residential and small C&I; and 3) HPP—hourly pricing for largest C&I customers. Unlike the other pilots, National Grid's pilot is designed as an "opt out" experiment. The utility will enroll customers in the default CPP rate but allow customers to opt out of that rate and either leave the pilot entirely or select a PTR option. [18]

As Figure 4-5 shows there will also be various combinations of technology options (home display units, smart thermostats and automatic HVAC controls, and load control devices.) Meter completion was scheduled for May 31, 2014 and the pilot TVR pricing starts January 1, 2014.

[18] According to National Grid of the first 5,000 meters installed, 297 or 6% of customers opted to not have meters installed.

Figure 4-5: National Grid's Smart Grid Pilot



As Figure 4-6 describes, the Massachusetts Distribution Companies currently have mandatory TOU rates (distribution portion only) for their largest C&I customers. However, for residential and small C&I customers there are legacy optional TOU rates that have been in place for some time but are not proactively marketed or well-subscribed by customers.

Figure 4-6: Legacy Massachusetts Distribution Companies TOU Rates

Current Time-of-Use Rates
FGE
Mandatory TOU for Large C&I: 30 customers
Optional TOU for General Service (closed): 3 customers
National Grid
Residential TOU: ~185 customers. Peak/Off-Peak = 6.644 / 5.82 ¢/kWh
C&I TOU: ~3,000 customers. Peak/Off-Peak = 7.53 / 0.00 ¢/kWh
NSTAR
Different programs by BECo, Cambridge and ComElectric
Residential TOU: 144 customers. Peak/Off-Peak -- varies by utility and rate
C&I TOU: 4,070 customers. Peak/Off-Peak -- varies by utility and rate
WMECO
Mandatory TOU for Large C&I: 243 customers. Peak/Off-Peak = 2.57 / .076 ¢/kWh
Optional TOU for others: 24 customers. Peak/Off-Peak = 2.67 / .076 ¢/kWh
TOU rates also apply to the transition charge

Table 4-9 is a summary of research done by the Office of the Attorney General on the use of TVR by other restructured states. It found that in each of the state's basic service is a flat rate, with a range of TOU and PTR rates that are available on a voluntary opt-in basis.

Table 4-9: TVR and Metering in Other Restructured States

State/Utility	Type of Metering Prior To AMI (Manual Read, AMR)	Type of Metering (AMI, AMR, or Enhanced AMR)	Basic Service Design	Type of TVR (TOU, TOU/CPP, or PTR)	On Basic/Default Service (supply) Distribution Rates, or Both	TVR Opt-In, Opt-Out, or Mandatory
Connecticut		Not AMI	Flat Rate	Legacy TOU	Supply Only	Opt in
Delaware	Manual Read	AMI	Flat Rate	TOU legacy and PTR	Both	Large scale PTR pilot underway; participation is opt in
District of Columbia*	Manual Read	AMI	Flat Rate	TOU legacy	Supply Only	Opt in
Illinois	Various	AMI (over 10 years)	Flat Rate	"Real Time" Pricing since 2009; Legacy TOU; PTR in future	Supply Only	Opt in
Maine*	Manual Read	AMI – CMP	Flat Rate	TOU	Supply Only	Opt in
Maryland*	Manual Read	AMI being installed	Flat Rate	Legacy TOU and PTR	Both	Overlay on Basic; participation is opt in
Michigan*	Manual Read	AMI (over 10 years)	Flat Rate	TOU	Supply Only	Opt in
New Hampshire		Not AMI	Flat Rate	TOU legacy	Distribution Only	Opt in
New Jersey		Not AMI	Flat Rate	TOU legacy	Both	Opt in
New York		Various; not AMI	Flat Rate	TOU legacy	Both	Opt in
Ohio*	Various	AMI only for Duke and AEP	Flat Rate	TOU legacy; pilot TOU for AMI	Supply Only	Opt in
Pennsylvania *	Various	AMI (over 10 years)	Flat Rate	TOU with installed AMI; PTR for one utility	Supply Only	Opt In
Rhode Island		Not AMI	Flat Rate	None	NA	NA
Texas*	Various	AMI	None	Unknown	Unknown	Opt in

Notes:
1. This information reflects residential rates only.
2. Several of these Distribution Companies offer optional EV charging TOU rate with or without AMI.
3. In these states, licensed suppliers can offer TVR but these rate options are not typical of most offers.
* means that one or more Distribution Companies in these states received ARRA funding for up to half of the AMI deployment costs.
4. Original spreadsheet also includes description of any TVR or PTR, and whether administered by utility or another (see original on the website at Steering Committee Meeting # 5)
Source: Office of the Attorney General

4.3. Metering

Metering issues and discussion permeated numerous Steering Committee meetings, as well as both Customer-Facing and Grid-Facing Subcommittee meetings. There were three different pieces of meter-related work overseen primarily by the Customer-Facing Subcommittee to help the Members garner a better understanding of the current metering infrastructure in Massachusetts.

1. The Distribution Companies were asked to reply to three sets of data requests to provide information as to their current metering infrastructure and replacement protocols (See Utility Metering Data Responses 1, 2, and 3)
2. Three meter-related hardware and software vendors provided the Steering Committee with presentations which focused on options for enhancing metering infrastructure, including types of technology, functionality, and cost ((See separate presentations on meters by Itron, AvCom, and Sentinel Works 1.9.13).
3. Lastly, the Customer-Facing Subcommittee and a metering working group that was formed to assist the Subcommittee spent a substantial amount of time reviewing and analyzing various metering technology options and the manner in which those technologies could support a range of customer-facing and grid-facing capabilities and functions. As part of this review and analysis, the Subcommittee and working group identified the incremental functionality of various technologies. The Subcommittee and working group also worked to develop cost ranges for the various technologies, including the meter cost, installation, and a range of necessary supporting infrastructure. The cost data was initially supplied by ITRON ((Itron Meters 1.9.13 and in subsequent discussions with working group and Subcommittee), and was then adjusted by the Distribution Companies based on their own distribution systems and experience gained from the pilots to date (See Metering Functions Costs & Applications 4.1.13.).

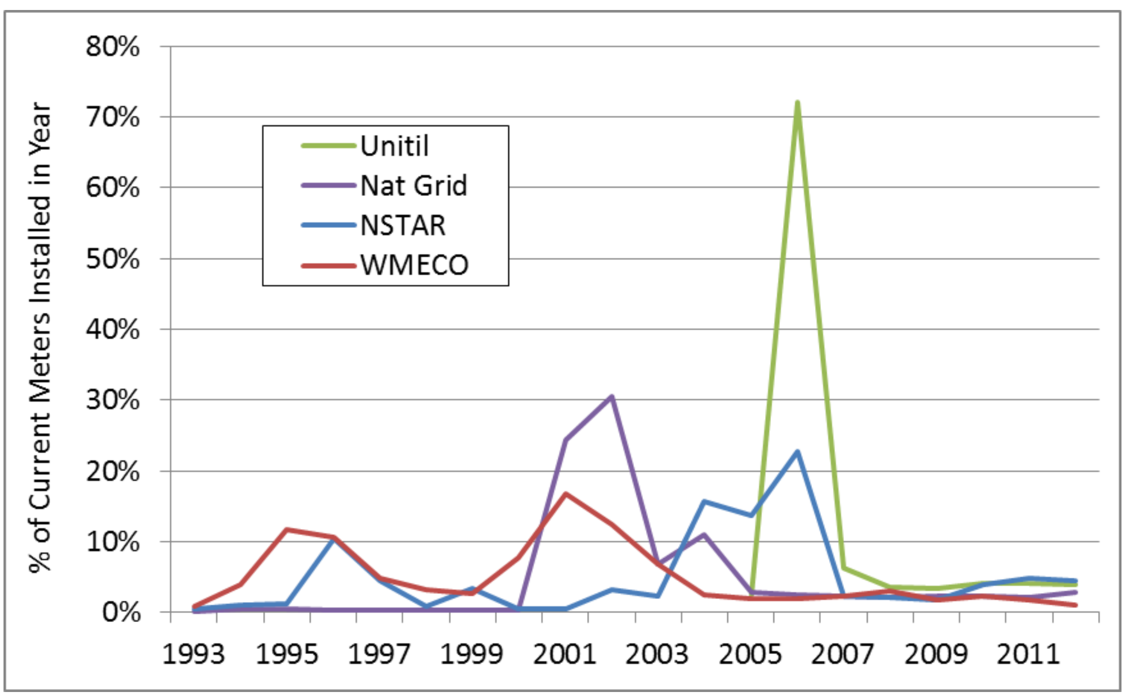
The Massachusetts Distribution Companies, with the exception of Unitil, all converted their meters from manual-read meters to AMR (automated meter reading) meters during the 1990's through the last decade. AMR meters are read from a moving vehicle rather than by a meter reader. Unitil converted its meters to AMI (advanced metering infrastructure) approximately 10 years ago, which allows Unitil to access the metered data remotely without having to drive by or manually read the meter. Table 4-10 shows the approximate age of the current meters for each Distribution Company, as well as the meters assumed book life and operating life. Based on the information provided by the Distribution Companies, the consultants calculated the last line in the table which shows the average life remaining in the existing meters.

Table 4-10: Utility Metering Infrastructure—Age, Book Life & Operating Life

	NSTAR	WMECO	National Grid	FG&E
Approximate average meter age (years)	Energy 10	Energy 12		
	Demand 7	Demand 8-9	17.8	7.1
	TOU 5	TOU 2		
Book life (years)	24	23	28.9	20
Operating life (years)	15 – 20	15 – 20	30	20 - 30
Approx. avg. life remaining (years)	5-15	3-18	12.2	12.9 - 22.9

Figure 4-7 shows a schedule of when the current meters were installed on each Distribution Company's system. The figure shows the percent of the total meters that were installed in each year. For example, of all the meters currently installed on the Unitil system, roughly 70 percent were installed in 2006. Roughly 30 percent of National Grid's current meters were installed in 2002. Each Distribution Company's current practice is to replace failed or aged meters with "like" meters (e.g., AMR with AMR). According to the distribution companies, the costs and complexities associated with integrating additional end-points and maintaining those interfaces make it impractical and uneconomical to do otherwise (see Metering Utility Data Responses 3).).

Figure 4-7: Schedule of Current Meter Installment: Percent of Total Installed in Year



The Customer-Facing Subcommittee, with the help of the working group referenced previously developed a range of metering technology options beginning with AMR, which is currently the most common meter type in Massachusetts, and ending with AMI. Included in this range are several options to enhance basic AMR meters either through home area networks or fixed external area networks. Both of these options are able to remotely provide information to the Distribution Company without having to gather the data during a drive by meter read. The Subcommittee and working group also learned about a new ITRON metering technology currently under development called a "Bridge AMI Meter" which can continue to act as an AMR meter, and then be switched remotely into AMI mode once a distribution company the utility has purchased and installed other supporting AMI infrastructure in place. Finally the work group and Subcommittee looked at Unitil's AMI system—which is a more limited AMI than full AMI, and looked at basic AMR with load control.

Table 4-11: Metering Technology Options

1) AMR (mobile) Only (NU/National Grid SQ) A) Swap Individual Meters for TOU -- Drive By
2) Enhanced AMR A) Home Area Network/Software (NSTAR Pilot) B) Fixed External Area Network/Software C) Swap Individual Meters for TOU – Wireless
3) Bridge AMI (new ITRON meter) A) AMR (mobile) Mode
4) Unitil's AMI
5) Full AMI
6) AMR & Direct Load Control

The working group then identified the potential meter-related functionalities of interest with 11 areas of focus shown Table 4-12. The working group and, ultimately the Subcommittee, then populated a matrix comparing each of the technologies in a different row with each of the 11 potential functions in a separate column to illustrate the technologies' capabilities. . (See Functionality worksheet in Metering Functionality Costs & Applications 4.11.13). A summary of the incremental customer-facing and grid-facing functionalities for key metering technology options is shown below in Table 4-13. Incremental Functionality of Metering Options. Table 4-13 illustrates that, as you progress from AMR through two types of enhanced AMR to AMI, additional functions in certain cases can and in other cases may be supported by the meters and associated infrastructure.

The Subcommittee and working group also worked to provide directional estimates of the costs related to the different metering technology options, including the costs of the meter and installation and a range of supporting infrastructure costs, as well as ongoing O&M costs. The cost ranges were developed with the assistance of Itron and with input from the Distribution Companies based on their experiences with their own infrastructure and pilot programs. (See Table 4-14 Metering Technologies and Costs below).

The Subcommittee also, as a final exercise, reviewed the meter-related customer-facing and grid-facing functionalities and compared them to various clean energy related activities, such as demand response, distributed generation, direct load control, electric vehicles, etc. Based on this review, it appears that there are two areas of meter-related functionalities with greatest relevance to clean energy activities: 1) communication to the meter and from the meter to customer devices; and 2) access to interval data on a real time basis. However, for some activities, such as electric vehicle recharging, if a TOU rate is sufficient, access to a TOU register, as opposed to interval data on a real time basis, might suffice to meet identified needs (See Functionality & Applications worksheet in Metering Functionality Costs & Applications 4.11.13 spreadsheet and accompanying text Metering Functionality & Clean Energy Activity Text 4.11.13 It should be noted that, simply because a certain type of meter can support a particular capability or function, does not mean that it is necessarily the only way to enable those functions or that it is cost-effective. For instance, communication for enabling direct load control can be accomplished via other communications protocols without going through the meter.

The Subcommittee and Steering Committee did not endeavor to perform a cost-effectiveness analysis of the different metering technologies and their associated incremental functionality benefits. Rather, the Steering Committee anticipates that such an analysis would need to be performed on a company by company basis at the appropriate time.

Table 4-12: Meter-Related Functionality

Customer-Facing	Grid Facing
1) Drive-By Meter Reading	8) Remote Service Connect/Disconnect Switch
2) TOU Register	9) Power Quality Reading
3) Interval Data	10) Outage Identification & Restoration Notification
4) Daily Read (at office)	11) Planning Data (snap-shot demand reads system read)
5) On-Demand/"Real-Time" Meter Reading	
6) Communication to Meter	
7) Communication Capability in Meter to Customer Equipment (appliances, thermostats, vehicles)	

Table 4-13: Incremental Functionality of Metering Options

Technology Options:	Customer-Facing	Grid-Facing
AMR	Drive-By Meter Reading; One-Way Communication	
Enhanced AMR (w/HAN)	AMR PLUS Communication to Customer Equipment and MAY enable Remote Meter Read, TOU Register, Daily & Real-Time Meter Read	MAY enable Outage ID & Restoration Notification
Enhanced AMR (w/Fixed Network)	AMR PLUS Remote Meter Read, TOU Register, Interval Data, Daily Read, and MAY also enable Real Time Data Read, Communication to Customer Equipment	MAY/limited Outage ID & Restoration Notification, and Planning Data
Full AMI	AMR (w/Fixed Network) PLUS Real Time Data Read, Two-Way Communication to Meter, MAY also enable Communication to Customer Equipment[19]	AMR (w/Fixed Network) PLUS Remote Service Connect/Disconnect Switch, Voltage Reading, Power Quality Reading

Note: "MAY" is due to fact that some of functionality may not be available depending on which meter model is purchased and with some models certain functionality is optional and requires additional fees. However, there are some functions that AMI can perform given current technology that are not available through AMR (e.g., remote service connect/disconnect switch, voltage reading, power quality reading).

[19] A Zigbee chip or in home device is also necessary

Table 4-14: Meter Technologies and Costs

	Meter (equipment) Costs	Installation Costs	Home Area Network Enablement	Software & Network Infrastructure	Other Smart Grid Infrastructure (OMS, DMS, GIS)	Total Cost (1)	DLC at Device (for interested customers)	Annual O&M (as percent of capital cost)
I) AMR Only (NU/National Grid SQ)	$30-50	$20-40	NA	$2	NA	$52-92	$100-150	10-30%
A) Swap Individual Meters for TOU--Drive By	$120	$20-40	NA	$2	NA	$142-162	$100-150	10-30%
2) Enhanced AMR								
A) Home Area Network/Software	$30-50	$100-200	$125-175	$2	NA	$257-427	$100-150	10-30%
B) Fixed Area Network/Software	$30-50	$20-40	NA	$15-30	NA	$65-120	$100-150	10-30%
C) Swap Individual Meters for TOU—Wireless	$300-600 (C&I only)	$20-40	NA	$2	NA	NA	$100-150	10-30%
3) Bridge AMI (new ITRON meter)								
A) AMR (mobile) Mode	$120	$20-40	$125-175	$ 2	NA	$247-437	$100-150	10-30%
B) AMI (network) Mode	$120	$20-40	$125-175	$50-125	$50-190	$365-680	$100-150	10-30%
4) AMI (Unitil SQ)	$70-150	$20-40	$75-150	$50-125	$50-190	$265-655	$100-150	10-30%
5) Full AMI (2)	$80-150	$20-40	$125-175	$50-125	$50-190	$325-680	$100-150	10-30%
6) AMR & Direct Load Control				$5-10			$100-150	10-30%

Notes:

(1) The Total Costs are simply a total of the min-max individual costs. Actual upgrade costs will vary based on functionality deployed.

(2) Ranges on AMI in part related to different functionality

(3) Cost estimates based on combination of ITRON supplied cost, and MA utility experience

(4) In 3B if Bridge Meter already installed in "mobile" mode, no incremental equipment or labor cost to switch to AMI (network) mode

(5) Row 2A is based on NSTAR pilot costs, scale deployment could be different

(6) Software/Network Infrastructure cost relatively fixed, and likely lower cost/meter for large systems than small

(7) Other Smart Grid Infrastructure can vary significantly depending on pre-existing infrastructure and what other options to pursue and based on ITRON's analysis of other jurisdictions.

(8) For DLC end costs/installation same, but communications cost vary significantly--i.e., likely less expensive for AMI

5. Principles and Recommendations

5.1. Consolidated Version

The following includes the principles and recommendations of the Steering Committee related to a wide range of grid modernization topics. The supporters of each particular option are noted in brackets ahead of each principle or recommendation. More detailed proposals on the appropriate regulatory and cost-effectiveness frameworks can be found in Chapter 6 and 7, respectively. "Consensus Recommendation" in this chapter means that all Steering Committee Member organization and other signatories to this Report agree with the recommendation or principle. (See Chapter 2 for Members in each stakeholder grouping, e.g., Clean Energy Caucus, and for Member short-hand, e.g., AGO.)

Grid Modernization Roles

1. [Distribution Companies/Clean Energy Caucus/Retailers/CLC] The role of the DPU is to establish the policy and regulatory framework; identify goals and objectives; oversee implementation, and enable sufficient cost recovery.
2. [Distribution Companies/Clean Energy Caucus/Retailers/CLC] The role of Distribution Companies is to develop and implement investment and operational plans to modernize the grid in a way that meets the outcomes within the policy and regulatory framework consistent with their obligation to provide safe and reliable and safe service at just and reasonable rates to customers.
3. [AGO] As part of their ongoing obligation to provide reliable and safe service to all customers, utilities should evaluate and invest in grid modernization technologies if:
    a. the benefits exceed the costs of the investment
    b. the investments are prudent, and used and useful
    c. investment is demonstrated to be least cost as compared to other alternative investments
    d. the investment will result in affordable rates and bills for customers, with rates based on current cost-causation and cost assignment principles. Specifically, subject to these constraints, utilities should plan for and adopt such grid modernization technologies that have been demonstrated to achieve some or all of the following results:
        i. reduce distribution and generation supply costs;
        ii. enhance the reliability of electricity service;
        iii. improve the operational efficiency of the grid;
        iv. enhance the ability of the grid to support the integration of distributed generation, demand response, storage technologies;
        v. enable customers to better manage their use of electricity;

vi. help achieve the state's environmental and clean energy goals;

vii. continue to support and sustain the competitive energy markets in New England and the provision of competitive electricity services in the Commonwealth, and;

viii. maintain the stability of the grid.

e. The Department should consider bill impacts, particularly for low-income customers, in its consideration of grid modernization investments, both in terms of individual investment proposals and the combined impact of these and other statutorily mandated investments in efficiency and renewable resources. Such a consideration may drive the need for identification of phased implementation and priorities in grid modernization.

Planning & Investment

1. [Distribution Companies] Distribution company investments in grid modernization capabilities, activities, and enablers should take into account the following:
    a. Desired outcomes (see 1.a. under Grid Modernization Responsibilities)
    b. Existing technologies already in use on their network;
    c. Geographic, demographic and system design characteristics of each Distribution Companies service territory;
    d. Cost-effectiveness of alternative capabilities, activities, enablers, and alternatives to meet the desired outcome; and
    e. Minimizing ratepayer impacts over the appropriate timeframes.
2. [Clean Energy Caucus/CLC] Distribution company investments in grid modernization capabilities, activities, and enablers should take into account the following:
    a. Identified outcomes, including specific targets and goals as ordered by the DPU;
    b. Existing enabling technologies already in place on their networks;
    c. Geographic, demographic and system design characteristics of each Distribution Company's service territory ;
    d. Cost-effectiveness of alternative capabilities, activities, enablers to meet the desired outcome; and
    e. Maximizing customer net benefits over the long term.
3. [AGO] The utilities investments in grid modernization capabilities, activities, and enablers should be guided by the following:
    a. The Grid Modernization responsibilities set forth above in Grid Modernization Roles Principle No. 3 above.
    b. Desired outcomes set forth in Chapter 3 of this report;

c. Existing enabling technologies already in place on their network;

d. Characteristics of the utility's customer base;

e. Geographic and demographic characteristics of each utilities' service territory;

f. The reasonable and prudent and used and useful standards;

g. Analysis of costs and benefits of reasonable options to achieve the desired results, and;

h. Affordability and minimization of ratepayer bill impacts.

4. [Distribution Companies] When establishing the regulatory framework, the DPU should take into account the following considerations:

    a. Distribution Company plans may need to account for long-term, multi-year efforts.

    b. Plans should be flexible and allow for updates to accommodate evolving technology

    c. The ultimate decision-making and responsibility for grid modernization investments remains with the Distribution Companies in keeping with their responsibility to provide reliable and safe service.

    d. Stakeholder input should be provided in a timely, efficient manner to allow investments and operations for safe, reliable service to continue.

    e. The Distribution Companies should consider the results from the ongoing Massachusetts smart grid pilots and other relevant pilot programs when evaluating potential grid modernization investments.

    f. Grid modernization should be grounded in the DPU's articulated principles regarding the development of service quality metrics and other performance metrics where appropriate.

5. [Clean Energy Caucus] DPU should issue an order in the follow-on proceeding recommended in Chapter 8 that specifies outcomes of the modernized grid at the level of detail required to provide sufficient direction for utility plans and filings and puts in place the appropriate regulatory policy framework (described in Chapter 6 and Appendix).

6. [Clean Energy Caucus] Each utility should file a company-specific grid modernization plan taking into account but not limited to the capabilities, activities, and enablers (shown in the Taxonomy chart in Chapter 3).

    a. Each plan should indicate how the utility plans to integrate distributed resources and new technologies and services to capture the operational benefits they can provide to the distribution system, improve distribution system reliability, enhance the provision of information to support competitive retail services, and coordinate with other distribution planning activities. These resources may include geo-targeting of energy efficiency, demand response, distributed generation and storage.[20]

b. Consistent with the goals of this report, the plan will specify incremental modernizing activities (beyond what is already happening through system planning) and describe how/whether they will further the integration of distributed resources, including electric vehicles, storage and microgrids. (For instance, the plan should describe the ways in which it will encourage distributed resources where they are valuable or useful; engage in more transparent system planning with longer planning horizons and sharing of information about plans to modernize grid-facing equipment; reduce times and costs for interconnecting distributed generation; and participate actively in opportunities for professional learning, research and technical collaboration to inform and enable transformational increases in penetration and optimization of distributed resources.)[21]

7. [Clean Energy Caucus] Utility grid modernization plans should be updated every 3-5 years (consistent with the regulatory framework) to reflect technology evolution and other new information

8. [Clean Energy Caucus] There should be a process for stakeholder input into individual utility grid modernization plans, including but not limited to the identification of new technologies and other related investments and benefits

9. [Clean Energy Caucus] Utilities should consider the results to date from the ongoing Massachusetts smart grid pilots and other relevant pilot programs when evaluating potential grid modernization investments, but should not wait to make grid-modernizing investments where benefits can be reasonably expected to exceed costs.

10. [Retailers/CLC] Each plan will describe the process and content with regard to the flow of meter data between the meter reading utility, the ISO-New England, retail electric suppliers and the customer.

11. [AGO] Utility plans would need to account for short-term, long-term, multi-year investment plans, and specific investment projects and proposals. The plans should include, where applicable, preliminary cost estimates, impacts on customer reliability, grid operations, usage reduction, peak load reduction, impact on energy prices, and bill impacts on customers by rate class.

[20] The planning for non-wires alternatives should take into account the work of the Massachusetts DG Collaborative on "the role of DG in distribution planning" (summarized in the 2006 Report to the DPU and other documents in **D.T.E. 02-38**) and the Standards for System Reliability Procurement approved by the RI PUC on July 25, 2011 in Docket No. 4202."

[21] For examples to build from, see the Appendix featuring the IREC/Sandia Labs Report entitled, *Integrated Distribution Planning Concept Paper: A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources;* the NIST Distributed Resources, Generators and Storage Domain Expert Working Group (DRGS DEWG) materials on the NIST Smart Grid Collaboration Wiki **at http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/DRGS;** *Integrating Smart Distributed Energy Resources with Distribution Management Systems*, EPRI, September 2012; and numerous other reports, as well as, the utility responses to Question 3 of the Grid-Facing Subcommittee's Round 2 Information Query..

12. [AGO] Stakeholders should continue to provide input into utilities grid modernization planning in the various Department proceedings as appropriate. As appropriate, developers, technology companies, individual customers and others with individual needs may seek to facilitate individual needs or desires through participation in Department proceeding, or direct contact with utility staff.
13. [AGO] Utilities should consider the results (after public review and consideration of evaluation reports by the Department) from the ongoing Massachusetts smart grid pilots and other relevant pilot programs when evaluating potential grid modernization investments. The utilities may find that customers could potentially benefit from testing certain grid modernization technologies, capabilities, activities, and enablers through additional pilot programs. If the utilities do conduct additional pilot programs, all program results should be made publicly available. However, customers should not fund research and development through pilot programs.
14. [AGO] Any new grid modernization process should consider how it interacts with existing related DPU processes and procedures, e.g., annual reliability reports; SQM; and DG Interconnection. A resolution for potential impacts on and conflicts with existing Department policies, processes, and procedures must be identified prior to adoption of any grid modernization policy, plan or process.

Risk & Reward/Cost Recovery

1. [Distribution Companies] Capital investments in new and innovative capabilities, activities, and enablers are inherently more risky than investments in traditional assets due to their unproven track record and, as a result, the standard for cost recovery needs to reflect this additional risk.
2. [Clean Energy Caucus/CLC] It should be recognized that capital investments in new and innovative capabilities, activities, and enablers may have different risks from investments in traditional assets. Although distribution companies currently bear the downside risk of disallowance if investments underperform, they should also have an opportunity to capture or share upside benefits when investments outperform expectations. The principle of risk symmetry is essential to promoting innovation and is recognized in the Utility of the Future Regulatory Framework
3. [AGO] Capital investments in some grid modernization technologies, particularly those that are new and innovative, may be more risky than investments in traditional assets. The level of such risk should be taken into account when determining the scope, scale, and potential bill impacts associated with such proposals. Customers should not bear the risk for new and innovative technologies.
4. [Utilities] The prudent used and useful standard should be used for grid modernization investments. Notwithstanding the foregoing, reasonable investments that attempt to achieve grid modernization objectives should be eligible for recovery from customers [AGO] As with any

other investment, utilities must be held accountable for estimated costs and benefits of grid modernization investments, and its estimated impacts on customer's bill and rates.

Cost Allocation

1. [Consensus Recommendation]Fair and equitable cost allocation and assignment principles should apply to determine cost responsibility for grid modernization investments.
2. [Distribution Companies/AGO] Grid modernization investments should be justified as beneficial to the customers that will pay for the costs of such investment through distribution service charges.
3. [Clean Energy Caucus] It should be recognized that utility investments in grid modernization that are prudent, used and useful will provide benefits to the system and customers as a whole and their costs should be recovered through distribution service charges. Interoperability.

Interoperability

1. [Consensus Recommendation] Interoperability is a key consideration and must be an element of any grid modernization plan filed by the Distribution Companies.
2. [Clean Energy Caucus/AGO] The utilities should be required to meet interoperability standards that are consistent with relevant industry standards (i.e., NIST) and subject to Department review and approval.
3. [AGO] Interoperability standards shall not be used to require or otherwise justify investments into new, risky and emerging technologies, investments that would undermine the affordability of customer's rates and bills, or that are not demonstrated to be cost effective, and prudent and used and useful.
4. [Clean Energy Caucus] MA utilities should adopt the same standards where possible; and could potentially develop a common set of standards as follow-up to this proceeding.

Open Access

1. [Clean Energy Caucus] Open access should be a key consideration in the evaluation of grid modernization technology and investment options to accommodate the evolution of new technologies.

Cyber-Security and Privacy

1. [Consensus Recommendation] Cyber-Security and privacy are key considerations and must be elements of any grid modernization plan filed by the Distribution Companies.
2. [Clean Energy Caucus/AGO] The DPU should require the utilities to develop and seek approval of Cyber-Security plans, policies, and protocols as part of each grid modernization plan (as well as through any other regulatory procedures that the DPU may require). Utilities should have

periodic reporting requirements to demonstrate compliance with protocols. (Note: Portion of the plans may require confidential treatment to ensure system security.)

Metering

Metering Functionality

1. [Distribution Companies/Clean Energy Caucus/Retailers/MA DOER/CLC] MA Distribution Companies' path forward for metering should take into account:
    a. The goals and desired functionality and outcomes
    b. the starting point of each Distribution Company, e.g., their existing metering infrastructure, communications systems, billing systems, etc.; and
    c. analysis of alternative investments/technologies and their relative costs and benefits.
2. [Clean Energy Caucus] A utility that is proposing a grid modernization investment must show clearly in their initial filing that the chosen technology (e.g., AMR, AMI) and vendor solution can functionally perform the tasks and capabilities upon which their benefit-cost analysis is based.[22]
3. [AGO] If a utility desires to install advanced metering capabilities in order to achieve certain goals and desired functionalities and outcomes, the utility should be required to demonstrate a net benefit of a full system wide advanced meter rollout. Otherwise, the utility should be required to provide technology to collect time of use data for those who request them, including electric vehicles and target resources on a beneficiary pays basis.
4. [Clean Energy Caucus] Metering of customer load (including that of electric vehicles) should be capable of realizing the benefits that result from the use of vehicle load to balance electricity demand and supply, smooth load curves, maintain operating frequency, and facilitate the integration of variable renewable resources.

Customer Choice

1. [Clean Energy Caucus/Retailers/Distribution Companies/CLC/MA DOER]
    a. Individual electricity customer usage information should be made available to the customer, or as directed by the customer, in a secure, convenient and timely manner to a 3rd party provider, vendor, or competitive suppliers pursuant to applicable laws and regulations. (e.g., through provision of uniform platforms and formats for access to customer data for customers and 3rd party provider, vendor, or competitive suppliers).

[22] There are certain functional capabilities that may or may not be possible with an "Enhanced AMR". As this report is finalized there are open questions regarding the distinctions between an Enhanced AMR and AMI. Utilities should have clear answers to functional questions at the time of their filing

2. [Distribution Companies] Any metering proposal must be considered within the context of state and federal policy and programs such as retail competition and energy efficiency and distributed resources.
3. [Distribution Companies] Any metering proposal should address provisions for opting in versus opting out and any associated customer costs.
4. [Retailers/Clean Energy Caucus/CEC] Any metering proposal and associated data-related infrastructure must give customers the power to choose – i.e., to make informed choices regarding energy product options (such as fixed and/or time-based prices for energy purchases, demand response, energy generation, energy storage, and electric vehicles).
5. [AGO] Individual electricity customer usage information should be made available to the customer, or as directed by the customer, in a secure, convenient and timely manner to a Competitive Supplier or Electricity Broker pursuant to 220 CMR § 11.04(12)(b) and other existing applicable laws and regulations.
6. [AGO] Opting Out of Advanced/Enhanced Meters: For a full meter rollout, customers should be able to opt-out of metering choices and/or metering-related functionality.

Consumer Protections

1. [Distribution Companies/Clean Energy Caucus/Retailers/MA DOER/CLC] Any advanced metering proposal should be implemented in a manner that ensures DPU approved consumer protections remain in place.
2. [AGO] Any metering investments/changes should be made consistent with pre-existing consumer protections which should remain in place.
3. [AGO/Clean Energy Caucus/MA DOER/Distribution Companies] Advanced meter investments (either AMI or enhanced AMR) should not result in reduced levels of consumer protections, especially relating to the implementation of billing, collection, payment plans, and dispute rights reflected in current DPU and utility policies and programs.
4. [AGO] Before entertaining any grid modernization filings or proposals, customer privacy policies and regulations must be reassessed and further developed to address the customer specific data that is enabled with some grid modernization technologies. Such policies should reflect and affirm that affirmative customer authorization is required prior to allowing utilities to enable access to such data to any third party, a Competitive Supplier, an Electricity Broker, including utility affiliates and otherwise comply with the General Laws and regulations promulgated thereunder. See, e.g., 220 CMR § 11.05(4).

Remote Disconnect/Connect

1. [Clean Energy Caucus] Utilities should take advantage of remote connection capabilities afforded by grid modernization technologies.
2. [AGO] Shut-offs for nonpayment should not occur remotely.

3. [AGO] The remote disconnection and connection chip or functionality of smart meters should not be installed for cost, consumer protection and cyber-security reasons.

4. [AGO] Utilities should continue to develop targeted collections programs and policies, many of which may reduce the incidence of disconnection for nonpayment, but any such initiatives should conform to existing consumer protection policies and programs.

5. [AGO] No third party should be allowed to access the utility's meter to remotely disconnect or reconnect the meter. Any third party or energy supplier should be required to implement metering actions through the distribution utility and demonstrate compliance with the same consumer protections as required by the distribution utility.[23]

6. [NSTAR/WMECO] Any remote connect/disconnect proposal should be implemented in a manner that ensures DPU approved consumer protections remain in place.

Evaluation of Meter Investments (and related communications & data management infrastructure)

1. [AGO] Any proposal to replace the current metering system and install Advanced Metering technologies (metering, communication systems, and meter data management systems) must demonstrate that the customer benefits will exceed the costs. This principle is particularly important due to the metering systems installed by Massachusetts distribution utilities that already reflect a high level of operational efficiency. Stranded costs should be included in this analysis.

2. [AGO] Investments in advanced metering systems should be justified as beneficial to the customers that will pay for the costs of such investment through distribution rates and through default service for generation supply. Benefits that may accrue to third party vendors or that enable services that may be offered by third parties should not drive such investment decisions unless the third parties are required to assist in payment for these incremental costs.

3. [AGO] In making an advanced metering proposal, utilities should consider and evaluate all options that may result in more effective use of the current metering system or more modest investments that would achieve agreed upon objectives at the least cost, such as direct load control.

4. [AGO] Any proposal for advanced metering and TVRs should rely on demonstrated results and such programs should not be implemented based on theoretical benefits, opportunities, & goals. At a minimum, the ongoing Massachusetts smart grid pilots should be evaluated and

[23] These positions are not intended to prevent the deployment of either direct load control or other forms of demand reduction of appliances and equipment behind the meter delivered via communications with the meter by either the utility or a third party provider. This footnote refers to programs that require consent of the customer per opt-in tariffs or bilateral agreements that may exist between the customer and the utility, or the customer and a third party demand response provider.

completed **prior to** making assumptions about the costs and benefits of significant additional costs for advanced metering and communication systems.

5. [NSTAR/WMECO]: Prior to installing AMI Metering systems, a cost-effectiveness analysis should be conducted to consider the cost effectiveness of such a deployment. This analysis should include assumptions on TVR rate design implementation. Subsequent implementation of TVR should be made in a manner that is consistent with the assumptions included in the initial AMI metering cost-effectiveness analysis.

Other Metering Principles

1. [Clean Energy Caucus/AGO] Performance metrics should be retained and/or established to measure any significant new investment in the metering system, including, but not limited to, the metering system's reliability, accuracy, and security through SQI or other appropriate places.

Integration with Communication Systems

1. [Clean Energy Caucus/AGO/Distribution Companies/MA DOER] Consider existing telecommunications networks when considering communication options for the metering and distribution systems as part of the cost effectiveness and security and reliability analyses.

Time Varying Rates Principles/Recommendations

Coverage: Customer Classes

1. [Clean Energy Caucus] TVR options should be analyzed for all customer rate classes, and made available to rate classes where benefits exceed costs-- although types of TVR may vary among rate classes

2. [AGO] TVR options could be analyzed for all customer rate classes, and made available to rate classes where benefits exceed costs-- although types of TVR may vary among rate classes

3. [AGO] The Department should not require utilities to provide TVR to all customer rate classes, but it should evaluate such options for each customer class.

4. [Clean Energy Caucus] TVR should be available to customers with distributed resources, including electric vehicles, and utility tariffs should be designed to encourage usage (charging) during off-peak hours with lower prices to minimize adverse impacts on the system and increase customer benefits.

5. [Clean Energy Caucus] Utilities should provide transparent information on the price of electricity as a transportation fuel and educate electric vehicle consumers on the benefits and impacts of using off-peak charging.

TVR Coverage: Distribution rates vs. supply/energy-side vs. both?

1. [Clean Energy Caucus/Distribution Companies/MA DOER] When designing a time-varying rate option to achieve applicable peak load reduction, demand response and/or other objectives, distribution utilities should analyze effectiveness of time varying rates for both supply and distribution rates.

2. [AGO] When designing a time-varying rate option or direct load control program to achieve applicable peak load reduction or demand response objectives, Distribution Companies should analyze impacts on the distribution and supply portion of the customer bill. Any promised benefits associated with generation supply prices should be accompanied by a plan to deliver those benefits to basic service customers.

Type(s) of Time Varying Rates

1. [Clean Energy Caucus] Evaluate the benefits and costs of a range of TVR options—seeking the appropriate option(s) for each customer class.

2. [AGO] When considering options for TVR for distribution utilities, the DPU should give priority to peak time rebate programs.

3. [Retailers/CLC] When considering TVR options for distribution utilities, the DPU should be thoughtful and attentive of the impact on the restructured competitive retail market, especially changes to Basic Service pricing and the implications for significant customer confusion.

4. [NSTAR/WMECO]: Options that include rebates should clearly identify the source to pay those rebates and the proposal should be cost-effective.

5. [NSTAR/WMECO:] The decision to pursue time varying rates needs to be evaluated in terms of the costs/ benefits produced over time.

    a. In order to enable TVR, all technology options should be explored and the focus should be on technologies that provide Distribution Companies with greater flexibility at a lower cost.

    b. Proposals to roll-out TVR should include life-cycle costs and costs associated with engaging and educating customers

    c. Market research should be conducted to evaluate customer interests, concerns, and understanding prior to any TVR deployment

    d. Time varying rates should adhere to cost causation principles

    e. TVR rates on the delivery portion of the bill should be implemented in conjunction with decoupling or a Lost Based Revenues mechanism.

Opt In vs. Opt Out vs. Mandatory Time Varying Rates

1. [Clean Energy Caucus/Unitil/NGRID] Time varying rates should be determined based on the same benefit-cost analysis framework as that used to determine metering and other grid modernizing technology cost-effectiveness. The analysis should consider the benefits and costs of alternative TVR designs and whether customers should opt-into, or opt-out of, the default TVR option.

2. [AGO] Time Varying Rates must not be mandatory for residential or low-income customers; consumers should be allowed to opt-in to TVR options.

3. [NSTAR/WMECO]: TVR must not be made mandatory. Consumers should be allowed to opt-in to additional rate options.

4. [Retailers/CLC] Basic Service or competitive retail supply for residential and small commercial customers should not be subject to a TVR design option but rather remain consistent with the present default service market design. However, the distribution utilities should have the opportunity to provide TVR for the transmission and distribution portion of the bill and consumers should be allowed to voluntarily opt-in to this TVR option.

Interface Between TVR and Competitive Markets

1. [Consensus Recommendation] Any TVR that may be implemented should support the Commonwealth's commitment to competitive wholesale & retail markets.

Evaluating TVR Options

1. [AGO] Options that include rebates should clearly identify the source to pay those rebates and the proposal should show that customer benefits exceed the customer costs.

Customer Education Around TVR-- [Clean Energy Caucus]

1. Commit resources within rates to educate and engage customers on TVR

2. Educate and engage customers for purpose of controlling energy use and support state's clean energy goals

3. New rate structures and information from advanced metering should foster customer education, behavioral changes and participation in energy efficiency and demand response programs.

Other TVR Related Principles/Recommendations

1. [Clean Energy Caucus] Time Varying Rates should be designed to facilitate the adoption by customers of a broad range of distributed energy resources and demand response technologies taking into account all relevant benefits and costs to enable them to capture the benefits these resources and technologies offer.

Distributed Energy Resource Ownership Principles

1. [Clean Energy Caucus] Consideration should be given to allowing utilities to own storage technologies and other distributed generation and distributed energy resources, where they would constitute distribution assets, to optimize the use of the distribution system.
2. [CLC] Consideration should be given to allowing utilities to own storage technologies.
3. [Clean Energy Caucus/CLC] Consideration should be given to allowing utilities to contract with 3rd parties for the use of storage and distributed energy resources, to optimize the use of the distribution system.
4. [Clean Energy Caucus] Utilities must demonstrate that the benefits of ownership or contracts for storage and/or distributed energy resources can be reasonably expected to exceed the costs over the life of the assets.
5. [CLC] Utilities must demonstrate that the benefits of ownership for storage or contracts for distributed energy resources can be reasonably expected to exceed the costs over the life of the assets.

6. Regulatory Framework Proposals

6.1. Introduction

This chapter contains Steering Committee recommendations for several regulatory frameworks that could be used for planning, reviewing and implementing grid modernization projects.

The Steering Committee developed two types of regulatory frameworks. First, there is a set of "comprehensive" frameworks; which are designed to provide recommendations for all of the regulatory aspects of grid modernization, including regulatory review, cost recovery, ratemaking, and performance standards. Each of these frameworks is mutually exclusive; and it would not be appropriate to adopt more than one of them. Second, there is a set of "complementary or targeted" regulatory policies that can be used in combination with the comprehensive frameworks, and in combination with each other.

6.2. Comprehensive Regulatory Frameworks

This section provides a summary of each of the four comprehensive regulatory frameworks. Appendix III provides additional details for each of the proposals summarized below. Table 6.1 provides a summary of the comprehensive regulatory frameworks.

Table 6-1. Summary of Comprehensive Regulatory Frameworks

	Enhanced Regulatory Model		GM Expansion - Pre-approval Process	Expansion of Investment Caps	Future Test Year	Utility of the Future, Today
Customer-, grid-facing, or both	Grid	Customer	Both	Grid	grid	Both
Summary	enhance reliability and facilitate DG	investigate / facilitate TVR DLC and metering	DPU review and approval of GM plans	build off current CapEx approach to include GM	align rates with cost incurrence in future	GM and rate plan review with performance incentives
Pre-approved budgets	No	yes	yes - in GM case	Yes	yes - in rate case	yes - in rate case
Public cost-effectiveness	No	yes	for some GM	post install	pre-install	Yes
Test year	Historic	historic	historic	Historic	future	Future
Cost recovery	base rates; DG customer	base rates; opt-in; and; direct assignment	rider	Rider	base rates & riders	base rates & reconciliation mechanism
Rate design	Traditional, enhanced TVR to be considered	Traditional, enhanced TVR to be considered	traditional, enhanced TVR to be considered	reflect costs, enhanced TVR to be considered	reflect costs, enhanced TVR to be considered	Start with traditional, reflect costs, enhanced TVR to be considered
Shareholder incentives	Traditional	traditional	within GM Plan proposal	Current	current	ROE indexed on performance
Performance targets	SQI enhanced, with additional targets, tbd.	SQI with additional targets, tbd,	within GM Plan proposal	SQ	SQ	enhanced – tbd

Note: See sections below for additional detail.

Table 6.2 provides a list of the Steering Committee members that have supported the different regulatory frameworks. Members were asked to identify their first choice of frameworks. They were also asked to identify other frameworks that they would consider acceptable if their first choice was not available.

Table 6-2. Support for Comprehensive Regulatory Frameworks

Regulatory Model Option	First Choice	Acceptable (first choice and other choices can likely support if first choice not an option)
The Enhanced Regulatory Model	AGO, Low Income Network	AGO, Low Income Network
GM Expansion - Pre-approval Process	NSTAR, WMECo, Unitil	NSTAR, WMECo, Unitil, National Grid, Cape Light Compact, General Electric, MA DOER
Expansion of Investment Caps		National Grid, WMECO, NSTAR, Unitil
Expansion of Investment Caps with a Multi-Year Plan		National Grid, WMECO, NSTAR, Unitil
Future Test Year Model		National Grid, WMECO, NSTAR, Unitil
Future Test Year with Multi-Year Plan Model	National Grid	National Grid, WMECO, NSTAR, Unitil, EnerNOC, , ENE, General Electric
Utility of the Future, Today[24]	ISO-NE, SEBANE, Cape Light Compact, NECHPI, ClearEdge Power, NEEP, ENE, NECEC, Mass CEC, CLF, EnerNOC, MA DOER, Ambri, CSG, General Electric; Bridge Energy Group, Retailers	ISO-NE, SEBANE, Cape Light Compact, NECHPI, ClearEdge Power, NEEP, ENE, NECEC, Mass CEC, CLF, EnerNOC, MA DOER, Ambri, CSG, General Electric, Bridge Energy Group, Retailers

The Enhanced Regulatory Model

Summary of the Proposal

The Department of Public Utilities ("Department"), in its Notice of Investigation issued in Docket D.P.U. 12-76, focused on potential "grid modernization" initiatives that span a broad range of options and topics. Consequently, the Stakeholder Working Group focused on an equally broad set of options and topics, which range from deployment of time varying rates and use of in home appliances to investment into reverse power flow transformers. Implementation of these types of initiatives implicates many complex questions surrounding homeowner investments on the customer side of the meter, the microeconomics of price response, the utility's distribution system investments to connect individual customers, and the annual expenses of a utility to maintain a reliable distribution system. The broad range of potential options and topics that have been discussed under the grid modernization rubric will require development of individual, targeted programs to be later reviewed within adjudicatory proceedings, as reflected in Chapter 8. [25]

The Department should first develop policies and objectives for establishment of grid modernization programs that achieve the best outcomes for customers at the lowest cost. The Enhanced Regulatory

[24] NSTAR Electric Company, WMECO and Unitil ("the Companies") appreciate that certain aspects of this framework would allow the Companies to optimize grid modernization planning and investment. In particular, the Companies are supportive of the provisions requiring company-specific GM plans using a forward-looking test year and PBR elements and the pre-approval of those plans within the context of formal regulatory proceeding. However, this pre-approval process should be applicable to and focused on targeted GM investments, rather than on traditional capital planning and investment processes. Distribution Companies have a core responsibility to provide safe and reliable service to their customers. Given that mandate, the Companies must retain the discretion to direct capital projects that operate to meet those dual responsibilities.

[25] Chapter 8 of this report provides a set of proposals for the next steps for the regulatory process.

Model provides a regulatory model that ensures maximum flexibility in addressing cost recovery for individual, targeted programs. It provides five submodels that may be used in conjunction with one another. Each submodel, described in the text below, is designed to facilitate recovery of costs associated with one of the five main programs or initiatives of grid modernization. These grid modernization technologies and initiatives should, among other things, enhance and improve distribution system reliability,[26] lower electricity costs, and enable grid modernization technologies in a least-cost manner.

The five submodels collectively enhance the current regulatory framework to facilitate deployment of grid modernization initiatives by the rate-regulated electric distribution utility companies in Massachusetts. The Enhanced Regulatory Model retains the existing structure for rate recovery. The utilities will continue to recover prudently incurred costs for grid modernization investments that are used and useful (as appropriately allocated according to the cost-allocation and assignment principles in place today) through base distribution rates, after accounting for bill impacts and affordability.[27] The utilities are allowed an opportunity to earn a return on their investments, which is recouped through base distribution rates at their cost of capital. Base distribution rates must be established in a base rate case proceeding.

Each submodel has individual features that may vary from the existing regulatory frameworks, as described in the Base Rate Case and Service Quality Index Program Model. For instance, pre-approval is required for a full metering roll-out, and establishment of time varying rate and direct load control programs. Also, all of the submodels contemplate annual reporting by the utilities on the status of their grid modernization plans and outcomes. The individual features of each submodel are described below.

1. Grid-Facing Reliability Investment Submodel

The utilities are continually modernizing their distribution systems to meet their current utility franchise obligations of providing safe and reliable service to their customers. The utilities generally have been using internal economic analyses in making the best of thousands upon thousands of small, medium and large expenditure decisions each year to modernize the electric grid, to maintain and in some cases improve system service quality and reliability to meet the Department's Service Quality Index Program requirements. As noted above, the current regulatory model allows the utilities to recover the utilities' prudently incurred expenditures made to modernize the distribution system, whether the associated costs are capital costs or operations and maintenance expenses. Utilities recover the expenditures through the base rates that are charged to customers.[28] The Department should not now adopt a new regulatory framework that would result in the micromanagement of the utilities and their

[26] From an affordability standpoint, it should be recognized that different customers or customer clusters may prefer or need higher levels of reliability in order to support their specific needs.

[27] The investments evaluated under the cost-effectiveness Option A, which is supported by the AGO and LIN, is also subject to these principles and regulatory requirements.

[28] Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid have a capital tracker that allows the utility to recover costs associated with incremental capital investments on an annual basis.

management.[29] Therefore, the Department should not adopt a new cost effective test to be applied to each and every grid modernization decision that a utility makes.

Since the Department already has a Service Quality Index Program for distribution system service quality and reliability, any enhancements to service quality and reliability outcomes that might come out of the Department's Grid Modernization investigation should be addressed and incorporated into the Service Quality Program through gradual improvements in those service quality indices. The utilities should continue to use their own internal economic analyses to make the appropriate decisions and the costs should be recovered through base rates in the same regulatory scheme that the Department has successfully employed for many decades. This way the utility has the economic incentive to minimize costs between base rate cases, while managing its costs and its system to achieve the reliability benchmark as set by the Department.[30]

The Grid-Facing Reliability Enhancement Submodel contemplates that the utilities will file annual grid modernization status reports. The reports should include a description of all significant new initiatives and investments intended to maintain and improve reliability as well as a description of significant changes to existing initiatives intended to do the same.[31] The Department, as always, would have the opportunity to review actual grid-facing expenditures in the base rate case to determine subject to cost allocation, whether they were affordable, least-cost, prudent, and reasonable.

The Department's regulatory model for treating distribution system service reliability is its Service Quality Index program. This reliability benchmark and the associated penalties and rewards system provide a model that can be enhanced to improve reliability to the extent desired. The Department would preapprove the desired enhancements in the benchmark reliability. Each utility would then be required to meet those standards by installing the most cost-beneficial options, albeit grid-facing technologies or traditional measures such as tree-trimming. The utility would recover any additional costs of the enhanced SQI program through the normal regulatory review in a base rate case.

2. Advanced Metering Submodel

Before each utility invests in a full, system-wide advanced metering initiative, it must seek Department preapproval of the investment to demonstrate that it has reliably projected that the initiative will provide net benefits to customers over the complete lifecycle of the meters under the Advanced Metering Submodel. This would occur in a pre-implementation filing. The utility would be required to use the Cumulative Net Present Value Revenue Requirement method ("Revenue Requirement Test").[32]

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[29] The Department has sought to ensure that the utilities retain management discretion in decision-making for capital improvements, subject to review under its prudence, and used and usefulness standards. *See e.g. Bay State Gas Company*, D.P.U. 09-30, p. 145 (2009) (declining to prescribe "an overarching method for the achievement of" replacement of certain natural gas mains and service.).

[30] The utilities that have capital trackers do not have the same incentive to minimize their capital costs. No new trackers should be established because this removes an economic incentive to minimize costs.

[31] The Department would decide what would constitute "significant" in this context.

[32] The Revenue Requirement here refers to the cost-benefit method called the Cumulative Net Present Value Revenue Requirement method. This test compares the expected life-cycle revenue requirements resulting from the program being

The Revenue Requirement Test is fully described in "Chapter 7: Cost-Effectiveness Frameworks", and is identified as in Option A proposed by AGO and LIN. If the Department finds there are net benefits to all customers and approves a metering initiative in the preapproval investigation, the utility would construct the system. The utility would then file a base rate case to seek to recovery of the costs of the initiative through base rates. This would entail the normal regulatory review of costs in a base rate case. The utility will be held accountable for projected benefits in the base rate case proceeding as well. If a full, system-wide rollout for an advance meter program will not provide net benefits to customers, a targeted meter program should be established for those customers requesting the meters. Those customers requesting the service would pay assigned the costs of the service including the costs of the meter.[33]

3. Time Varying Rate/Time of Use ("TVR/TOU") Submodel

The utilities should be required to facilitate time varying rates by offering to collect interval data electricity usage for customers who request the service under the Time Varying Rate - TVR Regulatory Submodel. The utility would allow retail competitive suppliers to provide all of these services. If the Department determines that the utility should be providing some or all of these services, the Department should establish guidelines for utilities to procure the energy supply through a separate auction process, similar to the manner in which it procures basic service supply. All of the utility's administrative costs of the program would be recovered through the charges to the customers requesting the service. This model would require no cost-benefit analysis.[34] The facilitation of the time varying rate for energy supply services would be provided on demand by the customer, regardless of the ultimate benefits to that customer. In the absence of a system-wide Advanced Meter rollout, those customers requesting the service would be required to have a meter, allowing for the collection of the interval usage data for which the customer would pay the costs of providing the service including the costs of the meter.

4. Distributed Generation Submodel

The Distributed Generation Submodel addresses integration of Distributed Generation through specific project-related investments. It recognizes the cost recovery process in place pursuant to the existing

operational and completely in base rates versus the revenue requirements of alternative scenarios in which the program is not operational and is replaced with other programs as they are needed. The difference between the stream of benefits and costs, when appropriately discounted and summed over time, is the net present worth of the resource. See e.g. Western Massachusetts Electric Company, D.P.U 85-270, pp. 71-75 (1985).

[33] Absent a full rollout, the utility should not make significant investments in additional communications systems to obtain additional customer usage data nor should a utility make other significant additional expenditures to obtain such data. The utility should largely rely on the existing infrastructure, although an additional meter purchase may be necessary.

[34] This is different from a scenario where there is a full meter rollout in the Advanced Meter Submodel where the justification of the rollout may include energy or capacity benefits received from a TVR/TOU Program. In that submodel, any energy benefits would be included in the cost-benefit analysis only to the extent that the benefits are returned to customers.

Department-approved interconnection tariffs. Under these tariffs, a Distributed Generator is assessed the costs associated with interconnecting to the distribution system. Thus, utilities should be required to seek Department approval in a base rate case proceeding for enhancements or changes to existing interconnection tariffs or establishment of new tariffs that pertain to cost recovery, cost allocation and cost assignment so that these provisions of the tariff are cost-based.

5. Direct Load Control Submodel

The Direct Load Control Submodel requires each utility to demonstrate the costs and benefits of a direct load control program of customers' appliances to the Department which could include a customer-by-customer targeted program and a system-wide footprint. The utility would be required to use the Revenue Requirement Test to conduct a cost-benefit analysis of its proposed program. The Revenue Requirement Test is fully described in "Chapter 7: Cost-Effectiveness Frameworks", and is identified as in Option A proposed by AGO and LIN.[35] If the Department finds there are net benefits to customers, and approves a plan for a direct load control program, then the utility would construct the system and establish the associated customer credit, after the normal regulatory review of costs and expected proceeds in a base rate case.

A system-wide program would demonstrate the costs and benefits of the build out of a communications system across the distribution system that would provide for control of customer appliances. The costs and revenues of the system would all be incorporated into rates for all customers. The customer-by-customer, targeted program would demonstrate the costs and benefits of using alternative existing communications systems to provide the load control, and all costs and revenues of the program would be directly assigned to those participating customers whose load is being controlled.

Grid Modernization Expansion - Pre-approval Process

Rationale for Proposal

This framework will allow for Distribution Company specific proposals to satisfy the DPU's grid modernization objectives while providing the following regulatory process benefits:

- Provide the DPU with the opportunity for a full review of any Distribution Company Grid Modernization plan prior to implementation.
- Allow each Distribution Company to expeditiously achieve grid modernization objectives by providing pre-approval of a proposal in a timely manner.
- Allow each Distribution Company to achieve grid modernization objectives in a way that is suitable for the unique characteristics of each system and rate plan.
- Support innovation in the industry as a whole and by Distribution Companies individually by enabling an incremental approach to infrastructure investment that allows for flexibility by the

[35] The test is also defined in footnote 32 above.

Distribution Company in the face of rapidly changing technologies while providing a mechanism for timely cost recovery of investments.

- Allow stakeholder input to the proposal via participation in the DPU adjudicatory proceeding.
- This would provide an opportunity to address a number of stakeholder issues, for instance:
  - Review of consumer protections and bill impacts;
  - Empowerment and enablement issues; and
  - Risks to various parties.
- Enable opportunities for review and approval of pilots of new technologies and innovative methods to provide safe, reliable service and to achieve other grid modernization objectives.
- Allows plans to be adjusted over time to ensure goals are met in the most cost-effective manner.

Summary of the Proposal

The Distribution Companies would file proposals with the DPU that meet the DPU's grid modernization objectives in a manner suitable for the unique characteristics of each system and rate plan.

Rules regarding stakeholder participation in the DPU review process would be identical to current rights afforded to participants in adjudicatory proceedings before the DPU.

As necessary, Distribution Companies should be permitted to request recovery of grid modernization investments through mechanisms outside of base rates, as determined by the Department. Cost recovery could be enabled consistent with existing Department precedent regarding historic test-years but may also be modified to accommodate a future test-year approach.

Performance targets would be addressed in the context of the DPU proceeding and would be specific to the nature of the investment.

Expansion of Investment Caps

Rationale for Proposal

This model would allow a utility with a capital investment recovery mechanism, such as National Grid's annual mechanism for in-service capital investments up to $170 million made in a preceding calendar year, to request an increase to its capital investment budget cap outside of a base rate proceeding for additional investment that a utility has determined is necessary to modernize the grid while maintaining safe, reliable service. There are many strengths to this approach. First, the approach provides flexibility regarding the level of investment that a utility deems necessary in any given year. A utility can elect to use its entire budget or can fall back to a lower level if appropriate. Second, the request can accommodate the effect of inflation on costs for equipment and manpower by allowing expansion of the capital investment budget. Third, the Department can determine the appropriate speed for modernization of the grid and improvements to safe, reliable service based upon the impacts to customers' bills from an expansion. Lastly, this approach speeds the modernization of the grid without the need for frequent rate cases yet maintains the full authority of the Department to investigate the prudence of the utility's investments.

<u>Regulatory Oversight</u>

Regulatory oversight would come in two phases. At the time that the Company submits its proposal to increase the spending cap for the upcoming year, the scope of the review would be limited to the Company's broad rationale for increasing its capital investment budget. So long as the request is consistent with the goals of modernizing the grid, the Department would not need to conduct a full adjudicatory proceeding to review the request to increase the capital investment budget. Rather, the Department would undertake a thorough review of the actual investments, projects and costs at the time that the utility requests recovery for in-service investment in the following year. Thus, the utility maintains the full risk of cost disallowance if its investments are deemed imprudent even though the Department may have approved an increased capital investment budget at the beginning of the year.

<u>Ratemaking/Cost-Recovery</u>

Cost recovery would be consistent with the parameters of the underlying recovery mechanism.

<u>Performance Targets</u>

Service quality metrics as determined by the Department from time to time through the existing service quality framework

Expansion of Investment Caps with a Multi-Year Plan

<u>Rationale for Proposal</u>

This model builds on the Expansion of Investment Caps model, with the same strengths, and additionally allows a utility to propose spending levels for a multi-year period instead of one year at a time. Grid modernization will not be accomplished within a year, and utilities will need to develop longer term strategies to achieve it. This model will enable a utility to develop such a plan and have regulatory pre-approval of the spending necessary to achieve it, subject to a later prudency review. It will allow regulators and customers to see the path of investment necessary to modernize the grid, and give greater real transparency regarding the utility's expected investment levels and goals for the investment.

<u>Regulatory Oversight</u>

Regulatory oversight would come in two phases. At the start, the Company would present its grid modernization goals for the next three years along with a capital investment budget to meet these goals for each year of the plan. So long as the request is consistent with the goals of modernizing the grid, the Department would not need to conduct a full adjudicatory proceeding to review the request to increase the capital investment budget. Rather, the Department would undertake a thorough review of the actual investments, projects and costs at the time that the utility requests recovery for in-service investment in the following year. Thus, the utility maintains the full risk of cost disallowance if its investments are deemed imprudent even though the Department may have approved an increased capital investment budget at the start.

In other respects this proposal is the same as the previous one.

Future Test Year Model

Rationale for Proposal

A forecasted rate year approach to cost of service provides utilities with greater incentive to invest in modernizing the grid because it would align the cost of service with the time period in which the costs would be incurred. As such, the revenues would be set to match expected costs, as approved after review by the Department, in the year of incurrence instead of costs incurred two years earlier. Modernizing the grid implies that additional investment may be necessary than what has occurred in the past. In addition, the availability of greater amounts of information would cause an increase in O&M costs to process and analyze the data for use in operating the distribution grid and providing service to customers. A benefit from use of a forecast rate year is the alignment of future plans to modernize the grid with the rates necessary to recover the costs. Department approval of the forecast rate year would align the company's future operations and investments in the rate year with the goals of the state energy plan that requires a modern grid. For the period beyond the rate year, an ongoing capital recovery mechanism for utilities with decoupled rates would enable more timely cost recovery of continuing capital investment, as more fully described in the "Expansion of Investment Caps" model. A future rate year does not eliminate the risk that the company must perform according to the approved plan and manage costs in a way to deliver the approved plan.

Regulatory Oversight

Comprehensive regulatory oversight, through the base rate case process, does not change as a result of this proposal, and the utility's burden of proof remains the same.

Ratemaking/Cost-Recovery

A forecasted rate year takes the inputs from the historic test year and inflates those values by inflation or actual forecasts of costs, e.g., capital investment plans, to derive the revenues necessary to run the utility in a forward-looking rate year. All elements of the forward-looking rate year including inflation in O&M expenses, forecasts of revenues and forecasts of capital investment are carefully reviewed by the regulator and intervenors to the case. The utility is required to justify the reasons for increases in costs in the future such as the rate of inflation for O&M costs or investment costs for projects and programs in the investment plan.

Performance Targets

Service quality metrics as determined by the Department from time to time through the existing service quality framework

Future Test Year with Multi-Year Plan Model

Rationale for Proposal

This model takes the same form as the Future Test Year Model with a forecasted rate year based upon an historic test year and forecasts of known changes such as capital investment. However, it would extend the plan for a number of years, usually three to five years. The benefit from multi-year plans, particularly when considering grid modernization, is that the utility's capital investment plan can be reviewed and approved for a number of years with recognition of and accountability for the goals of the plan. Also, multi-year rate plans improve the efficiency of regulation, particularly for utilities with decoupled rates, as they will not need to file multiple rate cases to acquire the revenues necessary to provide safe and reliable service through a modern grid. The length of the plan should be reasonable but not too long, as experience has shown that long multi-year rate plans tend to forecast the needs in the latter half of the plans poorly. A three year period provides the transparent view of the utility's plans going forward while avoiding the risks from unforeseen changes that affect utility plans in future years.

Regulatory Oversight

Comprehensive regulatory oversight, through the base rate case process, does not change as a result of this proposal, and the utility's burden of proof remains the same.

Ratemaking/Cost-Recovery

A forecasted rate year takes the inputs from the historic test year and inflates those values by inflation or actual forecasts of costs, e.g., capital investment plans, to derive the revenues necessary to run the utility through the multi-year period. All elements of the multi-year period including inflation in O&M expenses, forecasts of revenues and forecasts of capital investment are carefully reviewed by the regulator and intervenors to the case. The utility is required to justify the reasons for increases in costs in the future such as the rate of inflation for O&M costs or investment costs for projects and programs in the investment plan.

Performance Targets

Service quality metrics as determined by the Department from time to time through the existing service quality framework

Utility of the Future, Today

Rationale for Proposal

Since the primary mission of a distribution utility – the provision of safe and reliable service – is presently being accomplished without substantial grid modernization (GM), and since the incremental benefits of GM investments tend to accrue to others (i.e., customers, energy service and technology providers, and society in general) and not the utility, the risk of disallowance under traditional ratemaking practices (e.g., historical test-year approaches) discourages utilities from pursuing GM investments. Yet GM promises to bring substantial net benefits to society including improved reliability, reduced costs of service and customer bills, improved capacity utilization, reduced environmental costs, and increased customer choice.

Summary of the Proposal

To address the fundamental shortcoming in the incentive structure of traditional utility ratemaking practice, which imposes a barrier to cost-effective GM, we propose that a new regulatory model be adopted by the DPU – one that requires the utility to analyze GM investments from a broader societal point of view, gives the utility a degree of certainty regarding GM cost-recovery before it makes GM investments, and evaluates and rewards good GM plan implementation and performance on an ongoing basis. The regulatory model that we believe will encourage cost-effective GM efforts includes pre-approval and performance-based ratemaking (PBR) elements.

Under the pre-approval element, the utility files its GM plan – the plan may be comprehensive (both customer- and grid-facing elements), separate, or filed in phases depending on the specific circumstances of the utility (e.g., current state of metering and/or grid monitoring technology, pilot program status, etc.). The utility's GM plan would include the following elements:

- A description of the purpose and scope of the plan,
- An explanation of how the plan meets the GM values and objectives adopted by the DPU as a result of the Docket 12-76 Final Report,
- A business case evaluating the benefits and costs of the plan, which itemizes all of the benefits and costs and provides supporting documentation,
- A cost recovery proposal including PBR performance elements,
- A class ratepayer impact analysis, and
- An implementation plan.

If the grid modernization plan includes deployment of more advanced metering that accommodates time-based rates, a separate default service rate design plan that considers time-varying rates for each customer class, including a plan for low-income customer protection, should be filed as well. The distribution company should, in its GM or rate design filing, evaluate the range of rate design options, and recommend the appropriate option(s) for each customer class including whether the recommended rates should be an opt-in versus opt-out approach.

The DPU approves the GM plan if the business case is found to be cost-effective. If the DPU approves the plan, capital cost recovery associated with the plan is pre-approved. That is, investments authorized by the plan are deemed to be prudent and in the public interest, and return of and on authorized investments are reflected in customer bills incrementally as investments are made each year.[36] The

[36] Since GM plans that are capital-intensive could result in higher returns than an O&M-intensive plan, utilities may favor a capital-intensive plan over a more cost-effective O&M-intensive plan. To address this potential bias, the DPU should explore at a future time alternative approaches that perhaps reward utilities with additional returns for implementing a least-cost, O&M-intensive GM plan.

utility's GM plan should also include a detailed implementation plan that would allow the DPU to track the utility's progress toward completing its GM plan. This implementation plan would include a projection of the incremental investment that would be made by the utility over time to implement its approved GM plan. Recovery of capital investment will be via a "Capital Rider" that is set at the outset of each year based upon the utility's pre-approved capital budget and associated implementation plan.

At the end of each year, the utility's progress relative to its implementation plan is reviewed by the DPU. To the extent the utility is behind schedule, incremental investment associated with the delay is refunded to customers at the utility's weighted average cost of capital (WACC), which reduces the Capital Rider; likewise, if the utility is ahead of schedule, the additional investment associated with the advance is credited to the utility at its WACC, which increases the Capital Rider. Further, the utility's annual GM implementation progress report would also describe any cost overruns or efficiencies it had experienced over the past year. Cost overruns or efficiencies that cause the utility's annual rate of return to fall outside of a "dead-band" around its WACC are reviewed by the DPU, which may result in further incremental adjustments to the Capital Rider.

Under the PBR element, operational costs are recovered with service quality adjustments to give utilities the incentive to improve service quality. Operational costs are recovered using a formula base rate that is set initially via a traditional rate case, which is then adjusted over the term of the plan based on a formula such as the rate of inflation adjusted for productivity gains. Base rates are revisited and the PBR plan may be modified at intervals determined by the DPU (e.g., no more than five years). More frequent reviews of the PBR plan may be needed if the rate of change in technology and/or other exogenous macroeconomic variables are anticipated to be high or uncertain.

Perhaps most notably this model adds a substantive element of performance measurement to traditional cost recovery. The accountability of performance is offered as a counter-weight to the comfort afforded utilities from pre-approval and capital cost recovery via a Capital Rider. Generally, the performance targets and metrics would be designed around the most important, forward-looking assumptions that impact the business case (i.e., benefit-cost analysis) of the proposed GM investment. Actual performance targets and metrics can vary from utility to utility and should be offered by the utility in their GM plan.

For example, if the GM investment is dependent upon a certain percentage of its customers adopting demand response, distributed generation, or energy storage so that benefits outweigh costs, then a performance target/metric around that customer adoption rate would be formulated and linked to the increments/decrements around the baseline ROE for superior/poor performance with respect to those metrics. Further, service quality/system reliability metrics – e.g., SAIDI, SAIFI, CKAIDI, and CKAIFI – should be modified to reflect the expected improved service quality resulting from GM investments and should be similarly linked to the increments/decrements around the baseline ROE for superior/poor performance with respect to those metrics.

A utility that performs well relative to its performance metrics would have its return on equity (ROE) raised above its standard or baseline ROE – likewise, a utility that performs poorly relative to its performance metrics would have its ROE reduced below the baseline ROE. The performance reviews and PBR rate adjustments described above would occur annually at the same time the utility's progress toward completion of its GM implementation plan (and its Capital Rider potentially adjusted) is reviewed by the DPU.

Instead of reviewing the prudency of actual, booked costs as the basis for determining utility cost recovery, the focus will be on reviewing forward-looking cost and risk assumptions in the benefit-cost analysis of a utility's GM plan as the basis for utility cost recovery. This shifts the type of expertise needed to review GM plans. Assessing the reasonableness of cost projections and the connection to Docket 12-76 objectives becomes important because the prudency of investments authorized by the plan is presumed once a GM plan has been approved. However, these changes are needed to encourage utilities in pursuing forward-looking GM investment that bring substantial net benefits to society.

6.3. Complementary or Targeted Regulatory Policies

This section provides a brief summary of each of the complementary or targeted regulatory policies. Appendix III provides additional details for each of the proposals summarized below. Table 6-3 provides a summary of these complementary or targeted regulatory policies. Table 6-4 indicates those members of the Steering Committee that have endorsed each of the complementary policies.

Table 6-3. Summary of Complementary or Targeted Regulatory Policies

	Distribution Services Pricing	DR&TVR	GM Advisory Council
Customer-, grid-facing, or both:	CF	Both	CF or both
Rationale, Summary of, Model:	rates designed for new dist. goals	DPU approval for DR & TVR	stakeholder input
Regulatory Oversight:			
Utility pre-implementation filing:	Yes	Yes	yes
DPU review and approval of filing:	Yes	Yes	yes
Utility pre-approved budgets:	Yes	Yes	yes
Stakeholder input	Yes	Yes	yes
Utility reporting requirements	Yes	Yes	annual
Cost-Effectiveness:			
Explicit, public cost-effectiveness:	Yes	Yes	yes
Internal analysis by utility	---	---	---
Ratemaking and Cost Recovery:			
Test year.	historic or future	historic or future	---
Frequency of rate cases:	Current	Current	---
Cost recovery (base rates, riders)	forward rider	forward rider	---
Cost allocation (among customers):	case by case	case by case	customer class
Cost assignment (e.g., to 3rd party)	case by case	case by case	---
Rate design	based on dist. goals	TVR	tbd
Utility shareholder incentives:	case by case	case by case	ROE +
Performance Targets or Metrics:			
Role of performance targets	case by case	case by case	rewards & penalties
Performance targets used:	---	---	from GMAC

Note: See sections below for additional detail.

Table 6-4. Support for Complementary Regulatory Policies

Regulatory Policy Option	Supporters
Distribution Services Pricing	National Grid, Unitil, SEBANE, NECEC, NECHPI, Clear Edge Power, NEEP, General Electric, MA DOER, CSG, ISO-NE, MA CEC, Bridge Energy Group, ENE
DR & TVR	National Grid, Unitil, General Electric, MA DOER, Bridge Energy Group, NECEC, ISO-NE, CSG, ENE
GM Advisory Council	ENE, NECEC, NECHPI, ISO-NE, NEEP, SEBANE, CSG

Distribution Services Pricing With Transparency

Rationale for Proposal

The future of the distribution utility is evolving towards the integration of load and generation for the benefits of customers receiving deliveries and customers with generation behind or at the meter. Current cost recovery and prices assumes all customers receive deliveries of kWhs and that one-way power flow is the single reason for the distribution grid. However, the industry is changing with the advent of local, renewable generation, storage, microgrids (with capability to intentionally island from the rest of the grid as described in Chapter 3, Outcome 1) and electric vehicles and the resurgence of combined heat and power generation at customer locations or in stand-alone locations. The challenge for the distribution utility is mastering the integration of customer load and customer generation at the local level to provide low cost, safe and reliable delivery of electricity to customers, among customers and to markets.

The Commonwealth of Massachusetts has the opportunity to undertake an effort to design distribution pricing for the future and lead the industry in this effort. New pricing models would allow customers to pay for the level of service specifically requested by customers instead of socializing the costs across all remaining customers (or use) . At the same time, customers with generation or stand-alone generation may realize opportunities to provide services to the distribution utility by offering their demand response, energy efficiency, generation output, VAR support[37] and/or other services to allow deferral of investments by the utility that may be necessary to resolve short or long term reliability or stability issues on specific areas of the grid. New designs could make transparent the short or long-term benefits provided to promote certain technology or opportunity while clearly designing the ongoing cost responsibility for connection to the distribution grid. New designs can provide incentives for customers to embrace opportunities that provide savings in the costs to operate the distribution grid over the long-term while ensuring fair recovery of costs from all connecting customers.

Regulatory Oversight

A proposed rate design can be filed as a component of a rate case, a proposal for metering systems or independently. Utilities would file a proposal once they determine a valid business case for the new

[37] As stated in Chapter 3 (under Outcome 2), "Future applications [of Integrated Volt/VAR Control] may also incorporate distributed solar photovoltaic (PV) cells and other resources through the use of controllable inverters for VAR support."

pricing offering (rate design). The filing would include reasoning and analysis for the offering accompanied by a presentation of benefits to customers.

<u>Ratemaking/Cost-Recovery</u>

Where benefits accrue to individual customers, incremental costs would be paid for by customers on the proposed service offerings. Cost recovery for all elements of grid modernization would be facilitated by the addition of appropriate service offerings that fairly allocate cost responsibility among customers who benefit from grid modernization.

<u>Performance Targets (if any)</u>

Service quality metrics as determined by the Department from time to time through the existing service quality framework.

Regulatory Approval for Time Varying Rates and Direct Load Control

<u>Rationale for Proposal</u>

This model is complementary to the comprehensive regulatory models that discuss cost recovery for Grid Modernization investments. This proposal provides greater detail regarding the ability to design and receive approval for time varying rates (TVR) and direct load control (DLC) proposals. The adoption of these types of pricing options would provide opportunities for customers to save money on their electric bill by using fewer kWh when the cost to generate electricity is most expensive, especially capacity costs. The savings would be paid through estimated savings in wholesale power costs to provide electricity to customers.

The Rate design options may be filed for approval included as part of a rate case or apart from a formal rate case. Rate design options could be filed as part of a proposal to convert metering to advanced systems with greater capability to provide certain opportunities to customers. These rate options would be designed to be revenue neutral to approved rates on a class basis. The rate options could include Time-of-Use rates such as fixed period TOU, fixed period critical peak pricing (CPP), variable period CPP, hourly pricing of demand response credits for load control options, etc..

<u>Regulatory Oversight</u>

A proposed rate design can be filed as a component of a rate case, a proposal for metering systems or independently. Utilities would file a proposal once they determine a valid business case for the new pricing offering (rate design). The filing would include reasoning and analysis for the offering accompanied by the a presentation of benefits to customers.

<u>Ratemaking/Cost-Recovery</u>

Any incremental costs would be paid for by customers as determined during the adjudicatory proceeding before the DPU.

Performance Targets (if any)

Determination of performance targets would be determined as part of the proceeding, potentially aligning to present and future state energy policy.

The Grid Modernization Advisory Council

Rationale for Proposal

The Grid Modernization Advisory Council ensures that diverse stakeholder interests- including business, technology, engineering, consumer, low-income consumer, and environmental- are and continue to be represented throughout the grid modernization planning process. The Grid Modernization Advisory Council will facilitate the Department's review and approval process of multi-year grid modernization plans to encourage timely grid modernization investments and limit lengthy, contested regulatory processes. The Grid Modernization Advisory Council will institutionalize the stakeholder engagement started in the current DPU Grid Modernization process.

Summary of the Proposal

- The DPU defines the scope of grid modernization and objectives, requirements, and/or necessary functionalities of the modern grid for the Commonwealth.
- The DPU defines a standard framework for cost benefit analysis of grid modernization investments. The Grid Modernization Advisory Council provides input and recommendations on cost benefit analysis to the DPU.
- Utilities develop multi-year plans and budgets to achieve the defined grid modernization objectives. Stakeholders provide input to the multi-year plan and budgets, as well as review the cost benefit analysis of the proposed investments.
- Utilities submit multi-year plans, budgets, and cost benefit analysis to the DPU for review and consideration within a defined time period.
- Upon DPU approval of grid modernization plans, utilities are able to receive advance approval for grid modernization investments.
- Utilities implement grid modernization plans with on-going evaluation and annual reporting to the DPU. The process allows for mid-term course corrections.

7. COST-EFFECTIVENESS FRAMEWORKS

7.1. Introduction and Summary

Several groups of Steering Committee members submitted written proposals for how they would like cost-effectiveness issues to be addressed. Each of the proposals is presented below in their entirety, as proposed. The table below presents a summary of some of the key similarities and differences between the proposals. The table also presents the Steering Committee members that support each proposal.

Table 7-1: Summary of Cost-Effectiveness Proposals Submitted

Issue	Option A: AGO, Low-Income Network	Option B: Distribution Utilities; Clean Energy Caucus; MA DOER, CLC, Retailers	Option C: ENE
Which Grid Mod activities should be subject to a public cost-effectiveness analysis?[38]	All customer-facing activities, except those where service is only provided upon customer request and where customer covers the cost. (Not grid-facing investments which will be evaluated as they are today.)	All activities for which utilities seek pre-approval.	Might be more appropriate for some activities than others. An issue for further consideration.
When should such Grid Mod activities be subject to a public cost-effectiveness analysis?	For customer facing, prior to implementation on a projected basis, and as part of a rate case based on the actual costs and benefits.	Prior to implementation.	Prior to implementation. As part of GM planning process.
Should all costs and benefits be quantified in dollars in order to be included in the public cost-effectiveness analysis?	For customer-facing, yes. Costs or benefits that cannot be quantified in dollars should not be included in the analysis.	No. Quantify as many as possible, but include qualitative as well.	No. Quantify as many as possible, but include qualitative as well. Qualitative impacts may be weighted .
Which costs and benefits (i.e., impacts) should be included in the public cost-effectiveness analysis?	For customer-facing, quantifiable costs and benefits linked to the costs and rates paid by the utility customer should be included in the cost-effectiveness analysis. No participant or societal impacts.	The impacts to the utility, plus qualitative impacts related to utility investment, including reliability and safety among others. No benefits and costs that accrue solely to private, participant, third party included.	The impacts to the utility, participants, and society. The DPU may review analyses both with and without participant costs and benefits as part of the decision-making process.
What should the standard be for public cost-effectiveness analysis	For customer-facing: net benefits. For grid facing, cost-effectiveness should be performed through internal utility analyses.	Business case approach, where benefits justify the costs..	For customer-facing: Net benefits (investments and plans should be expected to produce outcomes the value of which is reasonable in relation to the costs). For grid-facing: Incremental grid modernization investments should be evaluated on a net benefits basis.

[38] For the purposes of this Chapter, "public cost-effectiveness" generally means a cost-benefit evaluation that is reviewed by the Department and other stakeholders, as opposed to a cost-benefit evaluation that is developed internally by an LDC.

How should the public cost-effectiveness analysis draw comparisons between alternative options?	For customer-facing, the analysis should compare alternative options to achieving the stated objectives using the net benefits test. (In contrast, use existing methods as basis for comparison for grid-facing investments.)	Analysis should compare alternative means to achieve the stated objectives.	Analysis should compare alternative means to achieve the stated objectives.
Should the public cost-effectiveness analysis consider incremental activities and costs or total activities and costs?	TBD for each customer-facing program. For grid-facing investments, no change.	Incremental, in the context of grid modernization investment.[39]	Should include activities that are incremental to the baseline or business-as-usual.

7.2. Proposals Submitted

Office of the Attorney General and Low Income Network

The Department should develop policies and objectives for such grid modernization programs that achieve the best outcomes for customers at the lowest cost, and any cost-effectiveness framework that the Department adopts should seek to achieve that end. The cost-effectiveness framework provided herein is intended to be used in conjunction with the Enhanced Regulatory Model. That model provides maximum flexibility in addressing specific groups of initiatives by providing five submodels that may be used in conjunction with one another. The five submodels include: the Grid-Facing Reliability Enhancement Submodel; the Advanced Metering Submodel; Time Varying Rate/Time of Use (“TVR/TOU”) Submodel; the Distributed Generation Submodel, and; the Direct Load Control Submodel. As described below, the cost-effectiveness evaluate for capital investments for grid facing would remain the same as it does today. However, the utilities would be required to evaluate a wide-scale deployment of meters and a direct load control program using a net benefits test as described more fully below.

Grid-Facing For Reliability Investments:

The current regulatory model allows the utilities to recover the utilities’ prudently incurred expenditures made to modernize the distribution system, whether the associated costs are capital costs or operations and maintenance expenses. Investments must also be used and useful and subject to cost allocation. Utilities recover the expenditures through the base rates that are charged to customers.[40]

[39] An important difference is that the supporters of the Utility of the Future regulatory framework would apply the same business case/benefit-cost/cost-effectiveness approach to a Distribution Company's total investment in the context of a future test year rate case. We all agree that certain "non-discretionary" investments (e.g., new customer connections, damage repair, among others) would not be subject to a formal benefit-cost analysis.

[40] Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid (“National Grid”) has a capital tracker that allows the utility to recover costs associated with incremental capital investments on an annual basis.

Under the Grid-Facing Reliability Enhancement Submodel, the utilities would continue to recover grid facing investment costs through base rates established in a base rate proceeding. The Department should not now adopt a new regulatory framework that would result in the micromanagement of the utilities and their management.[41] Therefore, the Department should not adopt a new cost effective test to be applied to each and every grid modernization decision that a utility makes.

Since the Department already has a Service Quality Index Program for distribution system service quality and reliability, any enhancements to service quality and reliability outcomes that might come out of the Department's Grid Modernization investigation should be addressed and incorporated into the Service Quality Guidelines through gradual improvements in those reliability indices. The utilities should continue to use their own internal economic analyses to make the appropriate decisions, and the costs should be recovered through base rates in the same regulatory scheme that the Department has successfully employed for many decades. This way the utility has the economic incentive to minimize costs while managing its costs and its system to achieve the optimal reliability benchmark in between rate cases.[42] The Department, as always, would have the opportunity to review these expenditures in the base rate case to determine, subject to cost allocation, whether they were affordable, least cost, prudent, and reasonable. Finally, the Enhanced Regulatory Model contemplates that the utilities will file annual grid modernization status reports that include a description of all significant new initiatives and investments intended to maintain or improve reliability as well as a description of changes to existing initiatives intended to do the same.[43]

<u>Customer Facing:</u>

Under the Enhanced Regulatory Model, the utilities could facilitate time varying rates by offering to collect interval electricity usage data for customers who request the service. If the Department has approved a system-wide rollout of advanced meters under the Advanced Metering Submodel, the utility will be able to provide the interval usage data for any customer who might opt in to a TVR or TOU program. Under the TVR/TOU Submodel, where a system-wide rollout is not approved, those customers requesting the TVR service would be required to have a meter, allowing for the collection of the interval usage data. Those customers would be assigned the costs of the service including the costs of the meter.[44] The utility would either allow retail competitive suppliers to provide all of the energy supply services, or if no competitive market develops, the utility may procure the supply through a separate auction process, similar to the manner in which it procures basic service supply. This program would

[41] The Department has sought to ensure that the utilities retain management discretion in decision-making for capital improvements, subject to review under its prudence, and used and usefulness standards. *See e.g. Bay State Gas Company*, D.P.U. 09-30, p. 145 (2009) (declining to prescribe "an overarching method for the achievement of" replacement of certain natural gas mains and service.).

[42] Utilities that have capital trackers do not have the same incentive to minimize their capital costs. No new trackers should be established because this removes an economic incentive to minimize costs.

[43] The Department should decide what is "significant" in this context.

[44] Under the scenario where the system-wide metering rollout does not occur, the existing communications and billing system would be utilized. The utility would not purchase new communications systems nor would the utility make significant other expenditures to facilitate this program.

require Department pre-approval. All of the utility's administrative costs of the program would be recovered through the charges to those customers requesting the service. This TVR/TOU Submodel would require no cost-benefit analysis, since the facilitation of the time varying rate for energy supply services would be provided on demand by the customer, regardless of the ultimate benefits to that customer.

Under the Advanced Meter Submodel, the customer facing initiative requires the utility to demonstrate the net benefits to customers through a program that is preapproved by the Department. Under this submodel, the utility would file with the Department a demonstration of the costs and benefits of an advanced meter investment prior to implementation. To the extent that the utility demonstrates that there are net benefits to customers, it would then make that investment and recover those costs through base rates. The Department would then review the costs of the program to ensure that the actual costs were in line with the utility's projected costs.[45]

The Direct Load Control Regulatory Submodel would also require the utility to demonstrate the net benefits to customers of investments in direct load control in a pre-implementation filing with the Department. Similarly, to the extent that the utility demonstrates that there are net benefits to customers, it would make the investment and recover those costs through base rates which the Department would review in a base rate case. In the pre-implementation filing, the utility would be required to demonstrate the economics of the direct load control, on a customer-by-customers basis, and on a system-wide rollout. A system-wide program would demonstrate the costs and benefits of the build out of a communications system across the distribution system that would provide for control of customer appliances. The costs and revenues of the system would all be incorporated into rates for all customers. The customer-by-customer, targeted program would demonstrate the costs and benefits of using alternative existing communications systems to provide the load control, and all costs and revenues of the program would be directly assigned to those participating customers whose load is being controlled.

The Advanced Meter Regulatory Submodel and the Direct Load Control Submodel require a utility to explicitly provide a net benefit analysis in the pre-implementation proceeding to demonstrate net benefits for customers. The principles that should drive this analysis would include principles listed below. However, these principles are universal to grid modernization.

<u>Cost Effectiveness Test Principles for All Grid Modernization Investments</u>[46]

- The costs and benefits included in a cost-benefit analysis must be quantifiable and quantified in dollars.

[45] In the case that a system-wide advanced meter investment is not approved, the utility would still be required to supply advanced meters to those customers who request them to facilitate time varying rates. See discussion regarding time varying rates, above.

[46] These principles are additive to the regulatory requirements discussed above (prudence, used and useful, least-cost, cost allocation) as well as affordability of rates and bills.

- Benefits that accrue to society or that reflect objectives and goals not linked to the costs and rates paid by utility customers should not be included in the cost-benefit analysis for grid modernization.
- The cost-effectiveness test should reflect the inherent risks in such analyses including the risks associated with predictions of energy prices, new technology costs and benefits, customer acceptance rates, life and persistence of benefits, and changes in regulations.
- The cost-effectiveness test should use a full life-of-the-measure analysis for those technologies that have achieved such.
- The cost-effectiveness test should include sensitivity analyses to show the range of potential impacts on rates and customer bills due to changes in key assumptions and variables.
- Any evaluation of grid modernization or smart grid investments should include an analysis of alternative means to achieve the stated objectives and estimated benefits, and any stranded costs associated with each alternative considered.

The best method that incorporates all of these principles is the cumulative net present value revenue requirement test. The Cumulative Net Present Value Revenue Requirement method ("Revenue Requirement Test") compares the expected life-cycle revenue requirements resulting from the program being operational and completely in base rates versus the revenue requirements of alternative scenarios in which the program is not operational and is replaced with other programs as they are needed. The difference between the stream of benefits and costs, when appropriately discounted and summed over time, is the net present worth of the resource. *See Western Massachusetts Electric Company*, D.P.U 85-270, pp. 71-75 (1985).

Table 7-2: AGO and Low-Income Network: Benefits and Costs Included in Each Application

Benefits	Metering Model for an Advanced Meter Rollout	Direct Load Control Model
Avoided Capacity Costs	Yes	Yes
Avoided Energy Costs	Yes	Yes
Avoided Transmission & Distribution Costs	Yes	Yes
Avoided Ancillary Service Costs	Yes	Yes
Revenues from Wholesale DR Programs	Yes	Yes
Short-Term Market Price Suppression Effects	Yes	Yes
Avoided Environmental Compliance Costs	Yes	Yes
Improved Reliability	No	No
Avoided Environmental Externalities	No	No
Other Benefits (e.g., market competitiveness, customer control, non-energy benefits)	No	No
Costs		
Utility Expenses	Yes	Yes
Utility Capital Costs	Yes	Yes
Utility Performance Incentives	No	No
Financial Incentive to Participant	Yes	Yes
DR Measure Cost: Utility Contribution	No	No
DR Measure Cost: Participant Contribution	No	No
Participant Transaction Costs	Assumed to be zero	Assumed to be zero
Participant Value of Lost Service	Assumed to be zero	Assumed to be zero
Increased Energy Consumption	No	No
Environmental Compliance Costs	No	No
Environmental Externalities	No	No

Distribution Companies and Clean Energy Caucus

The Distribution Companies and the Clean Energy Caucus have each submitted proposals which describe the appropriate benefit-cost analysis framework to be applied to Grid Modernization ("GM") investments. Both groups agree that GM proposals should include a ***business case*** to analyze the quantitative and qualitative benefits expected of a particular investment. The specifics of each proposal are included in the pages that follow, but the Distribution Companies and the Clean Energy Caucus each agree to these two introductory paragraphs:

The Proposed Framework: A Business Case

The Department should conduct a benefit-cost analysis of Distribution Company GM investments for which regulated entities seek preapproval. That analysis should include assessment of all costs and benefits, including those that are difficult to quantify, as well as the assumptions that underlie those costs and benefits. It is important to note that while cost-effectiveness tests may be applicable for certain investments in order to demonstrate that the benefits exceed the costs, it is not appropriate to apply those tests uniformly across all investment types. It is for this reason that we recommend that GM investment proposals should include a business case describing the benefits from the investment (which may be in the form of quantitative savings or qualitative improvements), the beneficiaries of the investment, the allocation of costs, and how the benefits are to be realized by the beneficiaries of the investment.

What is a Business Case?

A business case is a written document that captures the reasoning for initiating a project. A compelling business case adequately captures both the quantifiable and unquantifiable characteristics of a proposed project or investment. Information that may be included in a business case includes a detailed description of the project including scope and schedule, the rationale and business drivers for the investment, the expected costs, the expected benefits, any assumptions underpinning the evaluation of expected benefits, options considered, and expected risks, including sensitivities. From this information, the justification for the project is derived.

Distribution Companies

Introduction

The cost-effectives framework that is used to analyze, value and allocate the costs and benefits of proposed investments will be a central component of any Grid Modernization investment proposal submitted by the Distribution Companies. However, while cost-effectiveness tests may be applicable for certain investments in order to demonstrate that the benefits exceed the costs, it is not appropriate to apply those tests uniformly across all investment types. As such, these tests should be included in the context of a Distribution Company filing, as appropriate.

The challenges with adopting a standard cost-effectiveness test to be applied uniformly are many:

While costs are often easily quantifiable, benefits are not. The performance outcomes of proposed investment choices may include both quantifiable and qualitative benefits that are difficult to identify, and even more difficult to quantify.

Investment choices are often complex and involve evaluation of multiple alternatives with different costs, different benefits and different features that are valued differently by different consumers. Consumers may value the same features and benefits differently.

Even a consistently applied cost-effectiveness methodology for a given investment may produce different results for different distribution companies, as each is coming from a different starting point.

Due to these complexities, the distribution companies recommend that GM investment proposals should include a business case describing the benefits from the investment (which may be in the form of quantitative savings or qualitative improvements), the beneficiaries from the investment, the allocation of costs, and how the benefits are to be realized by the beneficiaries of the investment. . It should be noted that wherever feasible, the beneficiary of a particular investment should pay the costs of that investment. In addition, the business case would review any alternative proposals that were considered and reasons for the selection of the preferred proposal.

<u>What is a Business Case?</u>

A business case is a written document that captures the reasoning for initiating a project. A compelling business case adequately captures both the quantifiable and unquantifiable characteristics of a proposed project or investment. Information that may be included in a business case includes a detailed description of the project including scope and schedule, the rationale and business drivers for the investment, the expected costs, the expected benefits, any assumptions underpinning the evaluation of expected benefits, options considered, and expected risks, including sensitivities. From this information, the justification for the project is derived.

<u>Review and Approval</u>

In filing for pre-approval of grid modernization ("GM") investments before the Department, the Distribution Companies will seek approval of the *business case* supporting the recommended investments, and by extension, the GM investments themselves. All costs, benefits, alternatives, opportunities, modeling assumptions, risks, sensitivities and cost-benefit analyses will be considered and tested in the context of DPU review. Once decided, Department approval of the business case for such investments would reflect a finding that the benefits from the investment and underlying assumptions support prudent investments, as determined at the time of the DPU review. Department approval of the Distribution Company proposal does not relieve the Distribution Company of its obligation to complete all work in a prudent and cost effective manner, or to carry out the scope of work according to the requirements of the proposal. However, the finding would represent a finding of prudence with regard to the underlying analysis supporting the investment.

<u>Responses to Specific Questions</u>

1. Which GM activities should be subject to a public benefit-cost analysis?
    - When appropriate, GM activities should be subject to a public benefit-cost analysis. However, certain GM activities have benefits that are not easily quantifiable using cost-effectiveness tests. As an example, activities that improve safety, reliability and storm resiliency are difficult to quantify using such tests. The business case submitted by the Distribution Company in its GM proposal would demonstrate how the proposed GM investment may be cost effective when compared to other alternatives to accomplishing the same objective.
2. When should benefit-cost analyses be applied to grid modernization activities?
    - The benefit-cost analysis should be applied in the context of DPU review, prior to making an investment or initiating a plan.
3. Which costs and benefits should be included in the public benefit-cost analyses?

- The GM activities to which cost-effectiveness tests can be applied and the choice of cost-effectiveness test applicable should be determined as part of the business case submitted by the distribution company in its GM filing.

4. Should hard-to-quantify costs and benefits be included in the public benefit-cost analyses—and if so, which ones, and how?

- The cost-effectiveness analysis should be limited to quantifiable costs and benefits associated with a given investment.
- Other quantifiable and unquantifiable characteristics of a proposed project or investment should still be identified, analyzed and considered in the business case when determining whether the benefits exceed the costs.
- Qualitative costs and benefits will generally be determined by Department policy, including current expectations for safe and reliable service, Service Quality (SQ) standards, etc.
- Qualitative costs and benefits to be considered would include safety, reliability, and quality of service, as well as resilience, risk and other factors.
- Qualitative costs and benefits may also include intangible benefits, such as advancement of innovation supporting state policy objectives.

Clean Energy Caucus

<u>The Proposed Framework: A Business Case</u>

The Department should conduct a benefit-cost analysis of utility grid modernization investments for which regulated entities seek preapproval. That analysis should include assessment of all costs and benefits, including those that are difficult to quantify, as well as the assumptions that underlie those costs and benefits. While benefits and costs should be broadly construed so as to fully capture the value of proposed investments, the benefits and costs to private parties deriving from private investments should not be considered in the benefit-cost analysis.

Under the framework proposed here, utilities seeking preapproval of grid modernization investments would be expected to present a "business case" supporting the investment that would include a description of each quantifiable cost and benefit, the associated net present value (NPV), and the key assumptions that went into each value, along with a sensitivity analysis. Any costs and benefits of the proposed investment that the proponent believed should be considered but which could not be reasonably quantified would also be presented and explained.

While we expect that the Department should approve grid modernization investments when the benefits of such investments exceed the costs, the Department should avoid imposing a prescriptive threshold requirement that quantified benefits achieve any set ratio relative to quantified costs. Maintaining a flexible approach allows for a comprehensive assessment of the benefits, costs, risks, and uncertainties associated with a proposed investment that is sensitive to factors that are not easily quantified and to the full context of the proposed investment.

The Business Case Framework Best Fits the Grid Modernization Context

A business case framework will allow the Department to consider grid modernization investments in a holistic manner, without having to arbitrarily create a distinction between grid facing and customer facing benefits and costs, and without excluding consideration of benefits or costs that are difficult to quantify. This approach will also allow for the Department to consider all relevant information, including the benefits, costs, uncertainties, risks, and underlying assumptions associated with a proposed investment, and will better position the Department to factor risk and uncertainty into its evaluation of a particular proposal.

One example of a business case for making a grid modernization investment that the Department may want to consider as a model is the Smart Metering & Infrastructure Program Business Case developed by BC Hydro.[47] As exemplified by BC Hydro's business case document, the assessment we envision focuses on system related costs and benefits (though not necessarily exclusively so), is based on assumptions that are clearly labeled, and includes a sensitivity analysis that takes into account the upside and downside variability associated with the key drivers behind the benefits and costs.[48]

The approach that we recommend is tailored to the unique aspects of grid modernization investments, including the high degree of expected interactions between utility investments and private investments, the complexity of quantifying some of the benefits that grid modernization investments might provide, and the uncertainties that might exist for some grid modernization investments. Grid modernization investments are not the same as other investments for which benefit-cost analyses have been developed, and the benefit-cost framework adopted should reflect the unique aspects of grid modernization investments.[49] The approach proposed here borrows from and builds on the industry's experience with the application of the Total Resource Costs Test ("TRC") in the energy efficiency context, but differs in several key ways to account for the distinctive features of grid modernization investments. For instance, the proposal here allows for greater flexibility to consider benefits and costs that are difficult to quantify. It is also designed to allow a more nuanced consideration of the uncertainties surrounding benefits and costs. Further, while the approach we propose would include benefits and costs not included under the TRC approach, it would also not include all of the costs and benefits typically considered under the TRC approach. Specifically, the approach we propose would not include consideration of the benefits and costs to private parties deriving from private investments.

Summary of Important Principles

- A benefit-cost analysis of proposed investments is necessary to ensure that costs borne by ratepayers are appropriate relative to the expected benefits.

[47] BC HYDRO Smart Metering and Infrastructure Program Business Case Provides an excellent example. http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/projects/smart-metering/smi-program-business-case.pdf.

[48] An example of a basic framework for how benefits and costs might be presented as part of a business case, based on BC Hydro's business case document, is provided in Appendix I.

[49] A table describing some of the differences between energy efficiency investments and grid modernization benefits is included as Appendix II.

- A public benefit-cost analysis process should be included within regulatory frameworks that include preapproval of grid modernization investments. However, public proceedings may not be necessary or desirable in all circumstances and under all regulatory frameworks.
- The benefit-cost analysis should complement the larger regulatory framework and be used to expedite grid modernization investments that bring substantial net benefits to society.
- The benefit-cost analysis must consider difficult to quantify benefits and costs.
- Many of the benefits associated with grid modernization investments, including reliability and resiliency benefits, are likely to be difficult to quantify. These benefits must be considered to the extent a proponent can establish that they are real and have some likelihood of being realized.
- The Department should retain discretion to weight costs and benefits that have not been quantified in the evaluation process based on evidence presented.
- The DPU should adopt a flexible approach that allows for a comprehensive assessment of the benefits, costs, risks, and uncertainties associated with a proposed investment that would be sensitive to factors that are not easily quantified, rather than adopting a prescriptive set ratio by which benefits must exceed costs as a litmus test for cost-effectiveness,.
- The benefit-cost analysis should consider the costs and benefits of a grid modernization proposal that are incremental to the status quo.
- Customers or their service providers spending their own funds in response to utility grid modernization efforts are not incremental electric system costs.
- Uncertainties and risks associated with investments should be considered, but the existence of risk does not mean the absence of benefit.
- Sunk costs and stranded costs should not be considered in the benefit-cost analysis.
- Avoidance of reasonably foreseeable regulatory compliance costs is a benefit.
- The Department should retain the discretion to issue general guidelines or general orders that have the effect of approving certain categories of grid modernization investment if it finds that such guidelines or general orders are justified after an appropriate public process.

<u>Summary of Important Features of the Business Case Framework</u>

- Utilities seeking preapproval of grid modernization investments should present the Department with a business case with respect to its grid modernization plan, which estimates the net present value of incremental costs and benefits of the plan. Difficult to quantify benefits or costs shall be described to the greatest extent possible, with weights being assigned to such benefits or costs so that their relative importance in the business case is transparent.

  - Benefits may include, but are not limited to, avoided costs of transmission, distribution, capacity, energy; increased reliability and safety; and avoided environmental and compliance costs.
  - Costs may include, but are not limited to, additional capital costs, O&M, and administrative costs.
- A robust business case should start with a clear statement of the business objectives and a clear description of how the proposed grid modernization solution is expected to perform against any goals or benchmarks propounded by the Department. In some cases a utility may submit alternative proposals for consideration that might offer different benefit levels or achieve different goals at different costs.
- The life of the proposed measures should be used as the study period. However, the proponent of an investment should have the flexibility to recommend a different study period if such a period is justified.
- Proponents of grid modernization investments should be given flexibility to address risk in an appropriate manner given the nature of the investment proposed.
- A proponent of a particular grid modernization investment should propose a discount rate for assessing that investment. The Department should maintain discretion to select an appropriate discount rate on a case-by-case basis.

Clean Energy Caucus: Summary Matrix

Decision Points:	Recommendation
Should the DPU require explicit, public cost- effectiveness analyses?	In most cases, yes.
Which cost-effectiveness test(s) should be used?	Business Case Analysis as described above. This approach draws from more familiar approaches but is distinct from those approaches.
Should different tests by used for different activities?	No, this test can be applied to both grid facing and customer facing investments.
Should the C-E results be reviewed/approved by DPU prior to implementation?	Yes.
Should the C-E results be reviewed/approved by DPU after implementation?	Results should be reviewed to assess the likely effectiveness of future investments. After implementation review may be part of the larger regulatory framework.
What costs should be included?	Primarily, costs are expected to be associated with utility investments (including capital costs, O&M, administrative costs, etc.), other costs may exist. Private investments made by customers and others in response to utility investment should not be considered as costs in the analysis.
What benefits should be included?	Benefits should be construed broadly, but should focus primarily on the systems benefits associated with improving grid efficiencies. Private benefits accruing to customers and others deriving from private investment should not be considered as benefits in the analysis.
What study period should be used?	Useful life of the investments or other period shown to be justified.
What discount rate should be used?	TBD- rationale for the discount rate should be supported.
Should all costs and benefits be quantified?	To the extent possible.
If not, how should qualitative impacts be accounted for?	The Department should have discretion to weight qualitative impacts in accordance with evidence presented. The significance of qualitative impacts should not be arbitrarily limited relative to quantified impacts.
How should reliability be accounted for?	Reliability impacts should be quantified to the extent possible and appropriately valued using such measures as the value of lost load.
How should risk be accounted for?	Risk is accounted for in several ways. The discount rate used will reflect risk. Project risk will be accounted for by use of sensitivity analyses. Mitigation of risks should also be viewed within the context of the PBR model.
What type of evaluation, measurement and Verification will be required?	See above
What is the objective of the cost-benefit analysis?	To determine if the benefits outweigh the costs.
How should overlap between activities be accounted for?	See above

ENE

Introduction:

In the spirit of fostering a robust discussion of regulatory considerations for grid modernization, ENE offers the following comments on the role of cost benefit analysis. At the outset, we believe that to the extent reasonable, transparent cost-benefit analysis should be a significant factor in the Department's grid modernization decision-making.

ENE acknowledges that public, transparent cost benefit analysis might be more appropriate for some categories of grid modernization investments (i.e. customer-facing vs. grid-facing). Thus, we recommend that the distinctions among investments be an issue for further Department and stakeholder consideration.

The following recommendations are consistent with ENE's Grid Modernization Advisory Council (GMAC) proposal. ENE's regulatory proposal suggests that the Department adopt an analytical cost-benefit model with input from the GMAC and utilities, and selection or approval of grid modernization investments be informed by an evaluation of costs and benefits, among other factors as determined by the DPU. The GMAC proposal also recommends a comparative analysis of alternative investments or strategies (both traditional and grid modernization) that might achieve similar or better results.

Objective:

The Department should adopt a standardized cost-benefit framework for grid modernization investments and guidance for conducting analyses. Cost-benefit analysis is important to assure regulators, consumers, and other stakeholders that cost effective solutions are being proposed, and regulators need analysis to be able to make sound decisions. Cost-benefit analyses for grid modernization investments or approaches should require a meaningful assessment of the costs, benefits, and risks implicit in the investment. The cost-benefit framework adopted should include comparative cost-benefit assessments of alternative approaches (if any) to grid modernization investments, including examinations of different approaches for achieving the estimated benefits or objectives of the proposed investment.

Summary Recommendations:

- Existing cost benefit analysis frameworks are a good and flexible starting point. These frameworks can be adapted to address many of the new and unique issues related to grid modernization.
- Costs and benefits should be quantified to the extent possible. Where it is not possible to quantify benefits, a qualitative assessment of benefits may be included in a variety of ways.
- Utilities may present additional financial or business case analyses based on additional metrics and considerations.

Considerations and Recommendations:

- Discount rate: Energy efficiency program administrators in MA, VT, and RI use societal discount rates that are based on the long-term interest rate on a 10 year U.S. Treasury bond. RI and MA currently use a real interest rate of 1.15%. This rate reflects that fact that energy efficiency investments are predictable, low risk, and spread across all ratepayers. An alternative approach would be the use of a discount rate that is closer to the utility weighted average cost of capital. A recent report from the European Union suggests that the discount rate should balance the higher degree of risk associated with grid modernization investments with the potential societal benefits of these investments. Discount rates between 3.5 and 5 percent have been proposed in Europe.[50] Discount rates used in the analyses, and the rationale for their use, should be clearly documented.
- Uncertainty: Uncertainty regarding the magnitude of benefits from grid modernization investments should be incorporated into the cost-benefit framework through the use of sensitivity analysis. The magnitude of benefits from some investments might be dependent on the timing of the investment or the rate of customer participation or customer behavior change or persistence, among other elements of uncertainty. These factors should be included in the sensitivity analysis. Sensitivity analysis also serves to identify the determining factors for a positive economic and societal outcome.
- Double-Counting: The costs and benefits of existing statutorily required investments (e.g. existing energy efficiency programs or renewable portfolio requirements) should be evaluated separately from grid modernization proposals. Where there is program overlap or synergies, care should be taken to only count the costs and benefits of investments once.
- Comparing Alternatives: A cost-benefit assessment of grid modernization investments and approaches should include identification, analysis, and discussion of other investments or approaches (both “non-wires alternatives” or grid modernization and “traditional” investments, if any) that reasonably might achieve similar or better results. To the extent those expected benefits can be achieved through other investments, the cost benefit analysis should identify the incremental costs and benefits of the non-wires or grid modernization proposal.
- Bundling Investments: It may be appropriate to bundle a set of applications or investments together for cost benefit analysis purposes if the investments work together to deliver the intended functionality or objectives.[51]
- Emerging Technologies: To support the demonstration of emerging technologies, ENE supports the phased approach proposed by the Energy Storage Association.[52]

[50] European Commission Joint Research Center, Guidelines for conducting a cost-benefit analysis of smart grid projects. 2012.
[51] European Commission Joint Research Center, Guidelines for conducting a cost-benefit analysis of smart grid projects. 2012.
[52] From the Electric Storage Association regulatory framework proposal (introduced 5/14/2013):

Recommendations on Costs and Benefits:

- Costs and benefits transparently quantified and monetized to the extent possible.
- Cost benefit analyses should identify the costs and benefits of grid modernization proposals that are incremental to the baseline or business-as-usual scenario (i.e. identify what costs and benefits would be incurred in the absence of the grid modernization investment).
- All assumptions should be clearly documented, including assumptions regarding costs, benefits, discount rate, time frame, investments' useful life, bundling of investments, etc.
- To the extent that they can be reasonably quantified and attributed to the investment, environmental and reliability benefits should be included. A reasonable effort should be made to estimate reliability benefits separately for different customer groups.[53]
- Where benefits cannot be reasonably quantified, a qualitative impact analysis or description of potential benefits may be included to provide the Department with the whole range of potential benefits. The Department may consider weighting the relative importance of qualitative benefits.[54]
- Estimated costs may include, but not be limited to:
- Utility capital investments, including metering, infrastructure, software, communications, etc.
    - Operations & maintenance costs
    - Other program administrator expenses, including incentives paid to participants or third parties
    - Program administrator return, incentives, or rewards
    - Customer costs, including transactions costs, changes in reliability, and other costs associated with participation
    - Costs associated with increased energy consumption, including environmental compliance costs and negative environmental impacts

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"*Phase 1*: Utilities should have a small budget to be determined by the utilities and DPU (e.g., approximately $50 million), included in the rate base, which is devoted specifically to the pilot deployment of new technologies. These deployments should be fast-tracked to the field without regulatory hurdles.

Phase 2: Once a technology has been tested on the system, and a utility wants to expand the use of that technology, a more thorough regulatory proceeding should be adopted that includes cost-effectiveness analysis, utility reporting requirements and a cost-recovery mechanism.

Phase 3: After the technology has been utilized in the field for a sufficient period such that impacts are known, the technology should be considered as part of the class of regular transmission and distribution assets, and be eligible for funding by the utility through their annual budget for deployment without regulatory proceedings."

[53] Illinois Statewide Smart Grid Collaborative, Collaborative Report. 2010.

[54] European Commission Joint Research Center, Guidelines for conducting a cost-benefit analysis of smart grid projects. 2012.

- Potential benefits may include, but not be limited to:
    - Avoided capacity costs
    - Avoided energy costs
    - Avoided T&D costs
    - Avoided ancillary service costs
    - Reduced O&M costs
    - Other benefits associated with changes in the load curve
    - Market price suppression effect
    - Revenues from grid resources
    - Improved reliability
    - Avoided greenhouse gas emissions and other environmental externalities
    - Avoided environmental compliance costs

<u>Recommendations on Analytical Framework:</u>

- The cost-benefit framework should capture costs and benefits realized by utilities, customers, and society.. The Department may evaluate analyses both with and without customer costs and benefits. Energy efficiency models provide a good basis for capturing impacts on multiple parties.
- EPRI recommends directly applying traditional cost-benefit tests to grid modernization investments- "in general, these tests are applicable to smart grid evaluations because a major driver of smart grid benefits will be avoided supply costs realized through demand reductions, and assessing these impacts was the original driver behind the development of these models."[55]
- ENE contends that traditional cost-benefit tests are a good, flexible starting point for the Department's consideration. For example, the Total Resource Cost Test or Societal Cost Test could be modified to include the range of costs and benefits unique to grid modernization.
- ENE recommends that utilities should be required to utilize at least one modified cost-benefit framework, including the Total Resource Cost Test or Societal Cost Test.
- Additional financial analyses or business case analyses may be conducted. Alternatives may include the determination of deferred investment savings from non-wires or grid modernization investments through the use of net present value of the deferred revenue requirement analysis or the net present value of alternative investment proposals.[56,57]

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[55] Electric Power Research Institute, Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects. January, 2010).

[56] Rhode Island Public Utilities Commission, Docket 4202, Standards for System Reliability Procurement. July, 2011.

- All known and measureable costs and benefits should be transparently incorporated.

Concluding Recommendations

- The cost-benefit analysis is meant to provide the DPU with valuable perspective on the economic value of the grid modernization investment and should be given considerable weight by the DPU in its overall evaluation.
- The DPU should consider the cost-benefit analysis in addition to other factors in the decision-making process, such as public policy objectives, potential for synergies that meet multiple objectives, ability to meet identified system needs, anticipated reliability of the investments, operational complexity and flexibility, implementation issues, customer impacts, and other relevant decision-making factors.

[57] European Commission Joint Research Center, Guidelines for conducting a cost-benefit analysis of smart grid projects. 2012.

ENE Summary Matrix:

Decision Points:	**Recommendation**
Should the DPU require explicit, public cost-effectiveness analyses?	Yes
Which cost-effectiveness test(s) should be used?	Cost-benefit analysis should be employed. ENE recommends at least a modified Total Resource Cost or Societal Cost Test.
Should different tests by used for different activities?	Multiple analyses or frameworks can be presented.
Should the C-E results be reviewed/approved by DPU prior to implementation?	Yes
Should the C-E results be reviewed/approved by DPU after implementation?	On-going EM&V should inform future investment decisions and cost benefit assumptions.
What costs should be included?	Capital, O&M, , other potential costs
What benefits should be included?	Customer value, utility value, , ISO & wholesale market value, societal value, public policy value
What study period should be used?	TBD- useful life of the investments
What discount rate should be used?	TBD- rationale for the discount rate should be documented.
Should all costs and benefits be quantified?	Yes, to the extent possible.
If not, how should qualitative impacts be accounted for?	The C/B analysis is not the only factor in decision-making; DPU and utility decision making should also include an assessment of qualitative impacts, public policy objectives, etc.
How should reliability be accounted for?	To the extent reasonable, reliability impacts should be quantified and monetized for different customer groups.
How should risk be accounted for?	Risk and uncertainty should be addressed through the presentation of scenario analyses.
What type of evaluation, measurement and verification will be required?	On-going
What is the objective of the cost-benefit analysis?	See above
How should overlap between activities be accounted for?	Investments should not be double-counted. Existing statutorily required investments should be counted separately.

8. NEXT STEPS FOR THE REGULATORY PROCESS

This chapter presents several proposals for what the DPU can do to investigate these issues further, after this report is filed. The Steering Committee members did not reach agreement on a single recommendation for next steps. This chapter presents the each of the proposals separately, as they were submitted by several Steering Committee members.

8.1. Clean Energy Caucus/National Grid

Based upon the recommendations from this collaborative working group report, the Department should provide guidance to utilities as soon as possible, preferably by October 1, 2013, and encourage utilities, in the context of their next base rate proceeding, to include a grid modernization investment proposal consistent with the Department's directives.

Notwithstanding the foregoing, the Department should open a generic, stand-alone, investigation into the use of Time-Varying Rates. After a reasonable initial and reply comment period, the Department should issue an order in this proceeding by the end of 2013 that provides clear direction for utilities.

During any generic investigation opened by the Department, the Department should allow utility-specific grid modernization filings and should not suspend or delay decision on utility-specific proposals pending the outcome of any generic investigations.

8.2. NStar/WMECo/Unitil/Cape Light Compact

Recommendation is to follow a process similar to the Decoupling docket in 07-50-A.

- DPU would take recommendations from this report to open a Generic docket.
- Process includes:
    - Straw proposal (or set of straw proposals) and/or set of questions for parties to comment
    - Comments from interveners
    - Potential for the DPU to issue a second straw proposal, as necessary, followed by additional comments.
    - Would not require sworn testimony, but may be included depending on scope of the docket and preference of the DPU and interveners.
    - May also include technical sessions and hearings, as appropriate.
- Scope includes regulatory process, policies, regulatory frameworks, cost-effectiveness frameworks, principles. Does not include specific technologies or investments.
- TVR should be considered in a separate docket, after the initial docket described above is resolved.
- Does not preclude a utility-specific filing, prior to the completion of generic docket.

8.3. Office of the Attorney General and Low Income Network

Solicitation of Input on the Report

- The Department should establish a comment period to solicit comments on the Report after the Stakeholder Working Group files the Report with the Department on July 3, 2013.
- All interested parties, including members of the public who may not have participated in the Working Group process, should be allowed to submit initial comments and reply comments on the recommendations and proposals contained in the Report.
- The Department may opt to set a date for legislative-style hearings to gain a better understanding of the various proposals made within the Report through a dialogue with members of the Stakeholder Working Group, public officials and experts recommended by the Stakeholder Working Group.[58]
- As further explained below, once the Department completes the comment period and legislative-style hearings (if it opts to hold such hearings) concerning the Report, the Department should expeditiously (within 3 months or within some other reasonable time frame) issue an Order to provide the Distribution Companies and all other stakeholders with guidance for the path ahead to facilitate enhancement of the distribution system in Massachusetts.

A Roadmap for Implementing the Enhanced Regulatory Framework

The Office of the Attorney General requests that the Department issue an order to adopt the Enhanced Regulatory Model; a generic investigation is not needed to do so.[59] The model builds on the existing base rate case model to provide a framework that the Department may expeditiously adopt to encourage the utilities to facilitate enhancement of the electric distribution systems. As such, the utilities may move forward by facilitating enhancement of the electric distribution system, and will then be required to file a rate case to obtain recovery of costs. As explained below, the Department should take three main steps to implement the model:

- Increase the reliability standards provided under the Department's Service Quality Guidelines to facilitate reliability related grid-facing investments;
- Require the utilities to file a report on their grid-facing activities, which could then be implemented by the utilities after stakeholder input subject to review in a base rate case as outlined in the Enhanced Regulatory Model, and;
- Open investigations into Time Varying Rates ("TVR"), and Direct Load Control ("DLC") primarily to evaluate the utilities' roles in providing such services to their customers.

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[58] As noted below, the Department should review sweeping policy changes within the context of adjudicatory proceedings.

[59] The Enhanced Regulatory Model provides for a cost-effectiveness evaluation to review customer-facing activities that relies on a revenue requirements analysis as descried in Chapter 6 and 7 of this report. However, the evaluation recognizes that energy benefits may be included in the test under some circumstances. The extent of the inclusion of these energy benefits should be evaluated by the Department in the context of the contemplated TVR/TOU investigations.

No other action is necessary at this time given that the Enhanced Regulatory Model does not recommend major changes to the existing regulatory system. If the Department seeks to adopt a new policy that would result in major changes in the Commonwealth's current ratemaking and cost-effectiveness policies for capital investments, then the Department should initiate a formal proceeding to collect evidence in the way of sworn testimony, discovery, evidentiary hearings and briefing prior to making such changes. Implementation of a new policy such as a performance based rates will require the utilities to file a rate case.[60] Such is necessary to explore how major changes may significantly impact the affordability of customer rates, the operations of the distribution system and the like.

For grid-facing investments, implementation of the Enhanced Regulatory Model would entail the following:

- To encourage investment in cost-effective grid-facing technologies that enhance reliability, the Department should establish more stringent reliability requirements under the Department's Service Quality Guidelines in D.P.U. 12-120.[61]
- In its order on the Report, the Department should direct each utility to file a plan to illustrate their grid-facing plans for the future within 6 months of its order, or within some other timeframe that the Department deems reasonable. Consistent with the Enhanced Regulatory Framework, each utility should design its plan to meet the Department's reliability targets for each utility that are established pursuant to the Service Quality Guidelines established by the Department's Order in D.P.U. 12-120. The Department should solicit broad stakeholder input on the plans. Filing of the plans must not amount to pre-approval of specific investments, and recovery of costs to implement those plans would occur through a base rate case as outlined in the Enhanced Regulatory Model. The Department should also set a schedule for the utilities grid-facing plans to be reviewed in 3-5 years.

For customer-facing investments, implementation of the Enhanced Regulatory Model would entail the following:

- The Department should open generic investigations into the appropriate role of the Distribution Companies in offering TVR and Direct Load Control[62] options to basic service customers upon issuance of its order on this Report.
    - If after a generic investigation, the Department determines that distribution companies should offer TVR programs to achieve peak load reduction or other supply-related objectives, the Department should ensure that such programs should not be adopted or

[60] *See Decoupling Order*, D.P.U. 07-50-A, p. 82 (2008) (requiring each utility to file a rate case to implement decoupling after stating that "the Department can not conclude that it is appropriate to use these as initial rates [in place today] for decoupling without investigating issues related to cost allocation, rate design, and cost reconciling mechanisms.").

[61] From an affordability standpoint, it should be recognized that different customers or customer clusters may prefer or need higher levels of reliability in order to support their specific needs.

[62] The Department may distinguish between TVR that is enabled by advanced metering and direct load control programs that can be implemented with current metering systems so that direct load control programs could be designed and implemented sooner.

designed on a wide scale basis until the results from the Department-approved smart grid programs becomes available and have been publicly reviewed in a formal proceeding to consider the evaluation report submitted by each utility.

    - If the Department determines that the utilities should implement direct load control programs, the Department should require each utility to file a DLC pre-implementation filing to evaluate the costs and benefits of a utility-administered direct load control program for its customers and compare such a program in terms of costs and benefits to one or more such programs administered by third parties, consistent with the Enhanced Regulatory Model. This evaluation and consideration of each utilities' DLC proposal should be considered in a utility-specific adjudicatory proceeding

- In its order on this Report, the Department should not mandate that distribution companies deploy advanced metering. Any distribution company that seeks to deploy advanced metering should submit a business case that is considered in a formal adjudicatory proceeding before the Department, after the smart grid pilot programs are completed, as noted above. Such a proposal should be reviewed based on the cost effectiveness principles set forth in the Enhanced Regulatory Model and costs associated with approved advanced metering investments should be recovered in distribution base rates in a future rate case after it is determined that the benefits of the proposal have in fact exceeded the costs.
- The Department's order on this Report should also make clear that alternative suppliers and aggregators can offer TVR and DLC programs to customers at any time and that the costs associated with providing those programs, such as metering and billing expenses incurred by the distribution companies, must be allocated to the participating customers. This policy includes TVR options for Electric Vehicle customers.

These steps are either expressly contemplated by the Enhanced Regulatory Model, and if not, they should be implemented in a manner that is consistent with the spirit and letter of the model (as well as the companion cost-effectiveness framework provided in Chapter 7).

8.4. Targeted Electric Vehicle Proceeding

<u>Clean Energy Caucus, MA DOER, Direct Energy, CLC</u>

While the work in this proceeding has touched on the relationship and potential of electric vehicles and grid modernization, the specific issues needed to address and support consumer use of plug-in electric vehicles in Massachusetts should be the topic of a separate DPU proceedings. The States of California[63] and New York[64] have both completed (California) and recently instituted (New York) similar proceedings.

[63] See California Rulemaking 09-08-009 for completed proceedings. A general overview of the California Alternative-Fueled Vehicle proceeding is available at: http://www.cpuc.ca.gov/PUC/hottopics/1Energy/090814_ev.htm. The order instituting the rulemaking is available from: http://www.psrc.org/assets/3758/D_California_CPUCRulemaking_2009.pdf

[64] See State of New York Public Service Commission Case 13-E-0199. See: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=42691

Ten states have legislation that exempt EV Charging Services from utility regulation.[65] The record in Massachusetts must be established as priority for the DPU.

The Department should open a separate proceeding to consider the range of issues associated with the deployment of electric vehicles and their effect on the grid. The proceeding should address the barriers to Electric Vehicle Adoption including, but not limited to:

- Uncertainty as to the jurisdiction of the Department of Public Utilities over persons or corporations owning, controlling, operating, or managing facilities to provide supply electricity to the public to charge plug-in electric vehicles poses a barrier to private investment in plug-in electric vehicle charging infrastructure necessary to facilitate the widespread use of electricity as a transportation.
- To obtain the benefits that electric vehicles can bring to the grid the DPU must address the proper role for regulated utilities in removing barriers to the widespread deployment of plug-in electric vehicles, minimizing adverse impacts associated with vehicle charging, and maximizing the environmental and system benefits of the use of electricity as a transportation fuel.

The proceeding should also consider the following principles:

1. The Department should open a separate proceeding to consider the range of issues associated with the deployment of electric vehicles and their effect on the grid. The proceeding should address the following issues:
2. Support a strategy that addresses an open market approach for a variety of business models relating to charging system ownership and payment operations. The strategy needs to encompass current and future technology and interconnection issues as well as private/public sector barriers.
3. Incentivize off-peak charging of electric vehicles and avoid adverse grid impacts associated with vehicle charging.
4. Develop a transparent customer billing process that is fair to all customers, helps develop the electric vehicle market and identifies best practices for charging them to avoid demand pricing.
5. Encourage utilities to support short term and forward looking issues related to integrating electric vehicles into the grid to increase asset utilization and load management such as demand response as well as into the house or commercial property for emergency power.
6. Encourage utilities to develop information sharing capacity to educate consumers and commercial entities about the benefits of EVs and develop partnerships with stakeholders to further advance outreach efforts. Utilities should develop communication plans to identify EV owners in their districts to control local impacts and enhance reliability of electricity services.

[65] California, Colorado, Florida, Hawaii, Illinois, Maryland, Minnesota, Oregon, Virginia, and Washington. Source: "Lessons Learned – The EV Project Regulatory Issues and Utility EV Rates; Prepared for the US Department of Energy" and is available online at: http://www.theevproject.com/cms-assets/documents/103425-835189.ri-2.pdf

7. Utilities should be provided with timely notification about plug-in electric vehicle purchases and charging equipment installations to facilitate strategic system-wide planning and ensure adequate and strategic distribution system upgrades.

To support consumer acceptance and use of plug-in electric vehicles (PEVs), the DPU should seek to ensure that its regulations and policies promote the continuing evolution of the market for Plug in electric vehicles (PEVs) and for supporting services, while maintaining the safety and reliability of Massachusetts' electric grid. PEVs occupy an increasing share of the automobile market.

APPENDIX I: SUMMARY OF QUESTIONS FROM THE NOI

Current Status of Electric Grid Infrastructure as it Relates to Grid Modernization

- What grid modernization technologies and practices has each electric distribution company already implemented, and what plans does each company have for introducing additional technologies and practices?
- To what extent does each distribution company's recent investments in grid modernization, including advanced meters (e.g., Automated Meter Reading ("AMR"), Advanced Metering Infrastructure ("AMI")), affect decisions about future investment in grid modernization?
- What role do existing Department regulations, policies and practices play in encouraging or discouraging future investments in grid modernization infrastructure?

Grid-Facing Technologies

- What are the key grid-facing technologies and practices that the distribution companies should be implementing to maximize the reliability and the efficiency of the grid?
- How do grid-facing technologies and practices overlap with customer-facing technologies (e.g., advanced meters and communications systems) and practices, and to what extent do they need to be coordinated?

Customer-Facing Technologies

- How can customer-facing technologies, practices, and strategies be used in conjunction with time-varying rate design to (1) enable customers to manage their electric usage most efficiently and enable maximum customer cost savings; and (2) integrate resources such as distributed generation, electricity storage devices, and electric vehicles?
- What are the appropriate roles for the Department, distribution companies, and stakeholders in identifying customer-facing technologies to achieve these goals?
- How should the Department and other stakeholders ensure an open and robust market for third-party customer-facing technology providers and ensure adequate consumer protection?

Time-Varying Rate Design

- Which time-varying rate designs (i.e., time-of-use rates, peak-time rebates, critical peak pricing, real-time pricing) are most appropriate for Massachusetts customers, and should this vary by customer class and/or service territory?
- What factors should the Department consider in applying time-varying rate designs to basic service customers, and what impact might the application of these rate designs have on the competitive retail market?
- Should time-varying rate designs be mandatory, opt in, or opt out, and should designs vary by customer class?

Costs and Benefits of Grid Modernization

- What is the appropriate framework to evaluate the cost-effectiveness of grid modernization technologies and practices, including grid-facing technologies, customer-facing technologies, advanced meters, and time-varying rate designs?
- How should the Department value hard-to-quantify impacts such as improved reliability, increased customer choice, and reduced environmental impacts?

Grid Modernization Policies

- What role do existing Department regulations and policies play in encouraging or discouraging future grid modernization initiatives?
- What mechanism(s) should be considered for cost recovery of grid modernization investments?

The Pace of Grid Modernization Implementation

- How should electric distribution companies and the Department determine the appropriate sequencing and timing for implementing various grid modernization technologies and practices?
- To what extent, if at all, can and should distribution companies implement time-varying rate designs in advance of full-scale deployment of enabling technologies?

Health, Interoperability, Cybersecurity, and Privacy

- What steps should the Department take to address the health concerns associated with grid modernization that have been raised in a few other areas of the country?
- What steps should the Department take to promote open, interoperable grid modernization technologies?
- What steps should the Department take to address cybersecurity and privacy concerns associated with grid modernization?

APPENDIX II: COMMITTEE REPRESENTATIVES AND ALTERNATIVES

Organization	Steering Committee Reps	Steering Committee Alternates	Customer-Facing Sub Reps	Customer-Facing Sub Alternates	Grid-Facing Subcom Reps	Grid-Facing Subcom Alternates
Bloom Energy & ClearEdge Power (Fuel Cells)	Lisa Ward (CEP)	Charlie Fox (Bloom)	Lisa Ward	Charlie Fox	Lisa Ward	Charlie Fox
ChargePoint (EV/Charging)	Colleen Quinn	Scott Miller	Colleen Quinn	Scott Miller	n/a	n/a
Cape Light Compact	Joe Soares	Briana Kane	Briana Kane	Rebecca Zachas	Joe Soares	Rebecca Zachas
Constellation	Daniel Allegretti	Jeanne Dworetzky	Daniel Allegretti	Brett Feldman	Daniel Allegretti	Brett Feldman
CSG (EE)	Pat Stanton	Joe Fiori	Pat Stanton	Joe Fiori	n/a	n/a
Direct Energy	Marc Hanks	Chris Kallaher	Marc Hanks	Chris Kallaher	n/a	n/a
ESA & Ambri (Storage)	Katharine Hamilton (ESA)	Kristin Brief (Ambri)	n/a	n/a	Katharine Hamilton	Kristin Brief
EnerNOC (DR)	Herb Healy	Greg Geller	Herb Healy	Greg Geller	n/a	n/a
ENE	Abigail Anthony	Mike Henry	Abigail Anthony	Jeremy McDiarmid	Mike Henry	Abigail Anthony
GE Digital Energy	n/a	n/a	n/a	n/a	David Malkin	Byron Flynn
IREC	n/a	n/a	Erika Schroeder	Kevin Fox	n/a	n/a
ISO New England	Henry Yoshimura	Catherine McDonough	Henry Yoshimura	Catherine McDonough	n/a	n/a
Low Income Network	Jerry Oppenheim	Nancy Brockway	Jerry Oppenheim	Nancy Brockway	Jerry Oppenheim	Nancy Brockway
MA AGO	Sandra Merrick	Jamie Tosches	Nathan Forster	Anna Grace	Jamie Tosches	Anna Grace
MA CEC	Martha Broad	Galen Nelson	Martha Broad	Galen Nelson	Galen Nelson	Martha Broad

APPENDIX II continued						
MA DPU Electric Grid Modernization Committee Reps and Alternates						
Organization	Steering Committee Reps	Steering Committee Alternates	Customer-Facing Sub Reps	Customer-Facing Sub Alternates	Grid-Facing Subcom. Reps	Grid-Facing Subcom. Alternates
MA DOER	Birud Jhaveri	Dwayne Breger	Lou Sahlu	Gerry Bingham	Gerry Bingham	John Ballam
MA DPU (ex officio)	Ben Davis	Julie Westwater	Ben Davis	Julie Westwater	Ben Davis	Julie Westwater
MA DTC (ex officio)	Paul Abbott	Ben Dobbs	Ben Dobbs	Karlen Reed	Paul Abbott	Ben Dobbs
MA EOEEA (ex officio)	Steven Clarke	Barbara Kates-Garnick	Steven Clarke	Barbara Kates-Garnick	Steven Clarke	Barbara Kates-Garnick
National Grid	Peter Zschokke	Amy Rabinowitz	Peter Zschokke	Ed White	Cheri Warren	Chris Kelly
NE Clean Energy Center	Janet Besser	Charity Pennock	David O'Brien	Mark Kalpin	Michael McCarthy	Zachary Gerson
NECHPI (CHP)	Jonathan Schrag	Bill Pentland	Jonathan Schrag	Bill Pentland	Jonathan Schrag	Bill Pentland
NEEP (EE)	Natalie Hildt Treat	Josh Craft	Natalie Hildt Treat	Josh Craft	n/a	n/a
NSTAR	Larry Gelbien	Doug Horton	Doug Horton	Bryant Robinson	Amin Jessa	Bill McDonough
SEBANE/SEIA (Solar)	Carrie Hitt (SEIA)	Fran Cummings (SEBANE)	Carrie Hitt	Fran Cummings	Fran Cummings	Carrie Hitt
Unitil	Tom Meissner	Gary Epler	Justin Eisfeller	Cindy Carroll	Kevin Sprague	John Bonazoli
WMECO	Jennifer Schilling	Camilo Serna	Camilo Serna	Jennifer Schilling	David Wrona	Jennifer Schilling

<u>KEY:</u>

n/a = Organization is not a member of this Committee or-Subcommittee

<u>Additional Affiliations not noted above:</u>

Rebecca Zachas and Jo Ann Bodemer-BCK Law, PC (for Cape Light Compact)

Jeanne Dworetzky –Exelon (for Constellation)

Nancy Brockway – Nancy Brockway Associates (for Low Income Network)

David O'Brien-Bridge Energy Group (for NECEC)

Mark Kalpin - Wilmer Hale (for NECEC)

Michael McCarthy -Ambient Corporation (for NECEC)

Zachary Gerson   Foley Hoag (for NECEC)

APPENDIX III: DETAILED DESCRIPTIONS OF REGULATORY FRAMEWORKS

Enhanced Regulatory Model

Author: Office of the Attorney General
The proposal is fully described in Section 6.2.

The table below provides a summary of the key points.

Heading:	**Existing Model**	**Enhanced Regulatory Model**				
Column Title:	Base Rate Case and Service Quality Index Program Model:	Grid-Facing Reliability Enhancements Submodel:	Advanced Metering Submodel	Time Varying Rate/Time of Use ("TVR/TOU") Submodel:	Distributed Generation Submodel:	Direct Load Control Submodel[66]
Customer-/ Grid-facing.	Both.	Grid-facing.	Customer-facing.	Customer-facing.	Both.	Customer-facing.
Rationale for, or summary of, model	This column describes the existing base rate case model through which the Department of Public Utilities reviews the operations and costs of Massachusetts electric local distribution companies ("LDCs"), including grid modernization costs.[67] Base rates are set at a level that provides a	Enhance Service Quality Index benchmarks to allow utility to improve reliability in the most economical manner.	Allow LDCs to demonstrate net benefit of a full system wide advanced meter rollout. Otherwise require utility to provide technology to collect interval data for those who request it, including electric vehicles and target resources accordingly.	Add to Customers' Energy Supply service options to provide TVR/TOU offerings to shift system peak.	Facilitate the connection of Distributed Generation.	Direct control of individual customers load to provide maximum control of system peak load.

[66] The model refers to direct control of customer appliances and temperature control facilities, e.g. central air, water heaters and heat pumps.

[67] The NGRID, NSTAR, and Unitil smart grid pilot programs and the capital tracker to recover costs associated with incremental capital investments established for Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid are the exceptions to this general rule. The Department of Public Utilities has, pursuant to a directive in the Green Communities Act, established limited trackers for recovery of capital investments made in conjunction with a pre-approved smart grid pilot program. No new trackers should be established.

	utility an opportunity to recoup costs from customers for providing distribution service and to earn a reasonable return on its capital investment. Service quality is maintained through requirements under the Department's Service Quality Guidelines.					
Regulatory Oversight:						
Regulatory Elements:	Base Rate Case and Service Quality Index Program Model:	Grid-Facing Reliability Enhancement Submodel:	Advanced Metering Submodel:	TVR/TOU Submodel:	Distributed Generation Submodel:	Direct Load Control Submodel
Utility pre-implementa-tion filing	None	No change.[68]	Yes.	Yes.	Yes.	Yes.
Regulatory review and approval of filing	LDCs file a base rate request for review and approval by the Department. The filing includes a review of capital investments and operating expenditures. The Department conducts a proceeding, which entails discovery, expert testimony, evidentiary hearings, and briefings. The LDC's SQI program is reviewed annually.[69]	Yes for enhancement of SQI.	Yes.	Yes.	Yes.	Yes.

[68] "No change" indicates that there is no change from the existing model, as described in the Base Rate Case and Service Quality Index Program Model, although the Department would require improved reliability performance under its existing Service Quality Guidelines.

[69] Base rate distribution revenues may be reconciled through a decoupling mechanism, if approved by the Department as part of a base rate proceeding. NSTAR Electric Company is the only electric distribution company that does not have fully decoupled base distribution rates.

Utility request for pre-approved electric grid modern-ization budgets	None.	No change.	Yes.	Not applicable.	No change.	Yes.
Stakeholder input	Numerous opportunities: annual investigations into the LDCs Service Quality; periodic investigations into updating Service Quality requirements; base rate case proceedings, and; other DPU proceedings (distributed generation interconnection standards and annual capital tracker proceedings).	All previous opportunities exist plus the new opportunity to participate in the review of grid modernization reports is created.	All previous opportunities exist plus the new opportunity to participate in the pre-implementation proceeding and review of grid modernization status reports is created.	All previous opportunities exist plus the new opportunity to participate in the pre-implementation proceeding and review of grid modernization status reports is created.	All previous opportunities exist plus the new opportunity to participate in the pre-implementation proceeding and review of grid modernization reports is created.	All previous opportunities exist plus the new opportunity to participate in the pre-imple-mentation proceeding and review of grid moderniz-ation reports is created.
Regulatory Elements:	Base Rate Case and Service Quality Index Program Model:	Grid-Facing Reliability Enhancement Submodel:	Advanced Metering Submodel:	TVR/TOU Submodel:	Distributed Generation Submodel:	Direct Load Control Submodel
Utility reporting requirements	Annual Service Quality Reports.	Annual service quality reports and new grid modernization status reports.[70]	New grid modernization status reports.	New grid modernization status reports.	New grid mod. status reports.	New grid mod. status reports.
Cost-Effectiveness:						

[70] The reports should include a description of all new significant initiatives and investments intended to maintain or improve reliability as well as a description of changes to existing initiatives intended to do the same.

Explicit, public cost-effectiveness requirement[71]	None.	No change.	Revenue requirement Test[72]	No.	No	Revenue Requirement Test
Internal analysis by utility	Yes. LDCs evaluate potential capital investment and non-capital investment solutions using a cost-benefit analysis.	Yes	No	No	Yes	No
Ratemaking and Cost Recovery:						
General ratemaking (historic, future test years)	The Department uses a historic test year to establish a revenue requirement, the level of revenues to be recovered from customers through base distribution rates.	Historic test year.	Historic test year.	Not applicable.	Historic test year and customer-specific enhanced terms of service.	Historic test year.
Frequency of rate cases	Current law requires each LDC to file a rate case at least once every five years.	No change.	No change.	Not applicable.	No change.	No change.
Cost recovery (e.g., base rates, trackers)	Base rates. Each LDC must demonstrate the prudence and used and usefulness of its capital investments in a base rate case.	No change.	No change.	Not applicable.	No change.[73]	Subject to utility-specific proposed rollout.

[71] This proposal interprets the term "Explicit, public cost-effectiveness requirement" to mean a cost-benefit analysis methodology that is prescribed by the Department as opposed to a cost-benefit methodology that is developed internally by the LDC.

[72] The Revenue Requirement here refers to the cost-benefit method called the Cumulative Net Present Value Revenue Requirement method. This test compares the expected life-cycle revenue requirements resulting from the program being operational and completely in base rates versus the revenue requirements of alternative scenarios in which the program is not operational and is replaced with other programs as they are needed. The difference between the stream of benefits and costs, when appropriately discounted and summed over time, is the net present worth of the resource. See Western Massachusetts Electric Company, D.P.U 85-270, pp. 71-75 (1985).

[73] The Distributed Generation interconnection tariff governs cost recovery currently.

Regulatory Elements:	Base Rate Case and Service Quality Index Program Model:	Grid-Facing Reliability Enhancement Submodel:	Advanced Metering Submodel:	TVR/TOU Submodel:	Distributed Generation Submodel:	Direct Load Control Submodel
Cost allocation (among customer classes)	Employ cost causation principles, the practice of "assigning cost responsibility to the class of customers for whom the costs were reasonably incurred." (D.P.U. 94-101/95-36, p. 70).	No change.	No change for full rollout, but direct assignment for targeted investment to customers that request a meter enhancement /participate in a program.	Not applicable.	No change.	Subject to utility-specific approved rollout.
Cost assignment (e.g., to third party)[74]	Third party beneficiary pays for investments targeted for that third party.	No change.	If full rollout is not economic, direct assignment for targeted investment.	Yes – Assigned to the appropriate class of customers or individual customer, as applicable.	Per existing tariffs, investments made for connecting specific customers are paid for by those customers.	Subject to utility specific approved rollout.
Rate design	Traditional	No change.	No change.	Establish new supply service for TVR/TOU.	No change.	Subject to utility specific approved rollout.
Utility incentives (e.g. ROE, rewards/ penalties)	ROE for Rate Based Investments /Service Quality penalties.[75]	No change.	No change.	No change.	No change.	No change.
Performance Targets or Metrics:						
Role of performance targets	Maintain service quality.	Maintain and enhance service quality.	To hold the utilities accountable for estimated costs and benefits provided during the pre-implementation review.	Measure effectiveness of program to shift peak.	Enforce DG interconnect-tion timelines.	Measure effectiveness of program to shift peak.

[74] This proposal interprets "third party" to refer to an individual customer, group of customers or a noncustomer.

[75] The LDCs have opportunity to earn a fair rate of return on all capital investments including grid modernization investments. The Service Quality framework may result in penalties for subpar service quality.

Performance targets that will be used	Performance targets are set in the Service Quality Guidelines.[76]	Enhanced Service Quality Guidelines adopted in DPU 12-120. Additional targets as needed.	Review in rate case as a precursor to cost recovery.	Annual review of effect on peak in standalone proceeding.	Under Develop-ment by the D.P.U. 11-75Working Group.	Annual review of effect on peak in standalone proceed-ing.

[76] Service reliability includes SAIDI, SAIFI, CKAIDI, and CKAIFI.

Grid Modernization Expansion - Pre-approval Process

Authors: NSTAR, National Grid, Unitil, Western Massachusetts Electric

Summary of Regulatory Model

Regulatory Elements:	Description:
Customer-facing, grid-facing or both	Both
Rationale for, or summary of, model	Utilities submit proposals for grid modernization investments prior to initiating the plan.
Regulatory Oversight:	
Utility pre-implementation filing requirement	Filing required prior to implementation.
Regulatory review and approval of filing	Yes. DPU review and approval of a utility grid modernization proposal would occur in the context of an adjudicatory proceeding with set time frames for review and receipt of a final order to enable timely and efficient implementation of grid modernization initiatives.
Utility request for pre-approved GM budgets	Yes.
Stakeholder input	Yes. During the DPU adjudicatory proceeding interested stakeholders can participate.
Utility reporting requirements	Annual or as determined during the DPU proceeding. Utilities may report on progress (e.g., budget and installation status) as well as evaluation criteria. Depending on the nature of the grid modernization investment, a variety of reporting elements may be applicable.
Cost-Effectiveness:	
Explicit, public cost-effectiveness requirement	Traditional standards for reviewing projects necessary to maintain the safety and reliability of service to customers would remain in place. Cost-effectiveness tests may be applicable for certain customer and grid-facing investments in order to demonstrate the benefits exceed the costs. However, it is not appropriate to apply those tests uniformly across all investment types. As such, these tests should be included in the context of a utility filing, as appropriate. Following DPU approval of grid modernization initiatives, utilities shall pursue such initiatives efficiently.
Internal analysis by utility	Traditional standards for reviewing projects necessary to maintain the safety and reliability of service to customers would remain in place.
Ratemaking and Cost Recovery:	
General ratemaking (historic, future test years)	The process for general utility ratesetting does not change from the process that exists today. Base distribution rates will be set in the context of a general rate proceeding. As necessary for grid modernization investments, a separate funding mechanism outside of base rates will apply.
Frequency of rate cases	Present rules apply.
Cost recovery (e.g., base rates, trackers)	As necessary, utilities should be permitted to request recovery of grid modernization investments through mechanisms outside of base rates, as determined by the Department.
Cost allocation (among customer classes)	This would be addressed in the context of the DPU proceeding. A principle of the utility's proposal will be to consider the need for affordability for low-income customers.
Cost assignment (e.g., to third party)	The beneficiary of an investment in grid modernization should pay the costs, wherever it is feasible to do so.
Rate design	This would be addressed in the context of the DPU proceeding. A principle of the utility's proposal will be to consider the need for affordability for low-income customers.
Utility incentives (e.g. ROE, rewards/penalties)	This would be addressed in the context of the DPU proceeding.

Performance Targets or Metrics:	
Role of performance targets	This would be addressed in the context of the DPU proceeding.
Performance targets that will be used	Targets and goals would be an element of each utility proposal. Given that grid modernization investments serve to accomplish a variety of targets and goals, these would vary depending on the nature, scope, size, and timing of the investment. As such, it is premature to identify in this document specific targets or goals that should be considered.
Comments/Major issues	To enable timely implementation of grid modernization initiatives, specific timeframes should be established for DPU review and approval of utility grid modernization proposals.

Description of Regulatory Model

Executive Summary

Utilities would be allowed to submit plans to the Department of Public Utilities ("DPU") that meet the DPU's grid modernization objectives in a manner suitable for the unique characteristics of each system and rate plan. An individual utility approach accounts for the unique service territory characteristics and various technologies deployed by each utility currently. After receiving a utility proposal, the DPU would open an adjudicatory proceeding to investigate the plan. The establishment of specific timeframes for review and approval of utility plans is critical to ensuring the timely and efficient implementation of grid modernization initiatives.

Regulatory Oversight

The utilities would file proposals with the DPU that meet the DPU's grid modernization objectives in a manner suitable for the unique characteristics of each system and rate plan.

Rules regarding stakeholder participation in the DPU review process would be identical to current rights afforded to participants in adjudicatory proceedings before the DPU.

Cost Effectiveness

Traditional standards for reviewing projects necessary to maintain the safety and reliability of service to customers would remain in place. Cost-effectiveness tests may be applicable for certain customer and grid-facing investments in order to demonstrate the benefits exceed the costs. However, it is not appropriate to apply those tests uniformly across all investment types. As such, these tests should be included in the context of a utility filing, as appropriate. Following DPU approval of grid modernization initiatives, utilities shall pursue such initiatives efficiently.

Ratemaking & Cost Recovery

As necessary, utilities should be permitted to request recovery of grid modernization investments through mechanisms outside of base rates, as determined by the Department.

Performance Targets or Metrics

Incentives would be addressed in the context of the DPU proceeding and would be specific to the nature of the investment.

Stakeholder input to filing

Stakeholders would provide input by intervening in the docket before the DPU. In this way, stakeholders would be entitled to all privileges afforded to interveners for providing input to inform the DPU's review of a utility proposal prior to approval.

A formal requirement for obtaining stakeholder input prior to a utility filing would interfere with a utility's planning processes. This approach is consistent with current regulatory practice.

Utility reporting requirements

Reporting requirements should be specific to each plan but at least annually. Depending on the grid modernization objectives ultimately endorsed by the Department, investments might span a variety of technologies and horizons, so allowing for flexibility to address in the context of a specific proposal is appropriate.

Utilities may report on progress (e.g., budget and installation status) as well as evaluation criteria. The nature of the grid modernization investment may warrant a variety of variables and elements for reporting (e.g., technologies with different lead times, installation times, and evaluation criteria, as well as other complexities). Reporting requirements would be proposed by the utility in its initial filing.

If a cost recovery mechanism is approved by the Department, annual reporting to request cost recovery would be necessary.

Comments/Major issues

The DPU's review and approval process must contain specific timeframes for review and approval of grid modernization investments. A protracted review and approval process with no clear end-date for issuance of a final order jeopardizes the utility's ability to make efficient and timely investments in grid modernization.

Strengths and Weaknesses of the Regulatory Model

Strengths

This framework will allow for utility specific proposals to satisfy the DPU's grid modernization objectives while providing the following regulatory process benefits:

- Provide the DPU with the opportunity for a full review of any proposal prior to implementation.
- Allow stakeholder input to the proposal via participation in the DPU adjudicatory proceeding.
- This would provide an opportunity to address a number of stakeholder issues, for instance:
    - Review of consumer protections and bill impacts;
    - Empowerment and enablement issues; and
    - Risks to various parties.

- Allow each utility to expeditiously achieve grid modernization objectives by providing pre-approval of a proposal in a timely manner, and in a way that is suitable for the unique characteristics of each system and rate plan.
- Support innovation in the industry as a whole and by utilities individually by enabling an incremental approach to infrastructure investment that allows for flexibility by the utility in the face of rapidly changing technologies while providing a mechanism for timely cost recovery of investments.
- Enable opportunities for review and approval of pilots of new technologies and innovative methods to provide safe, reliable service or to achieve other grid modernization objectives.

Weaknesses

This proposal as constituted does not include a specific requirement for a date by which utilities should file a plan, which could potentially delay implementation of a plan.

Expansion of Investment Caps and Move to Future Test Year

Author: National Grid

Utility investments in infrastructure are driven by the obligation to provide safe and reliable service to customers. As a result, utilities are modernizing their infrastructure at a pace that considers the safety and reliability priorities of their investment plans, available technologies, the current design of their systems, and concerns about costs to customers, without necessarily taking full advantage of opportunities to modernize the grid for the future. In this paper, National Grid describes four alternatives to the current regulatory framework which will enable utilities to begin making meaningful investments in grid modernization to better meet the needs of customers both today and tomorrow, while at the same time maintaining the traditional focus on safety, reliability, and cost.

Two of the options are variations on capital investment recovery mechanisms currently in use by some Massachusetts utilities. The first option would allow a utility with such a mechanism to seek Department approval to exceed the annual investment cap for grid modernization spending, subject to an after the fact prudency review as with all capital investments. The second option is the same as the first, but would allow a utility to seek Department approval for a multi-year investment budget, to enable more long term planning and investment. The third option is to move from a historic test year to forecasted test year for ratemaking with ongoing capital recovery mechanisms under decoupling, as historic spending levels are by definition not indicative of the costs of modernizing the grid. The fourth option is the same as the third, but provides for a multi-year rate plan, under which the Department would review a utility's plan for the following three years and set out the course for grid modernization.

In order to set the stage for increased investments in grid modernization, the Department does not need to do everything all at once. Rather, it can make a series of small, but important, incremental step changes to the regulatory framework in Massachusetts by considering the annual capital investment budget review and pre- approval process as a first step, with other changes to the regulatory framework potentially implemented based on experience and the desire to achieve particular grid modernization goals. As discussed below, National Grid recommends that the Department take this first incremental step change by allowing National Grid to make a proposal to the Department under Menu Option 1, to change the spending level under its capital investment recovery mechanism, to invest in grid modernization.

Today's Framework

Current investment decisions are consistent with the concept of "good utility practice," i.e., investments that are similar to investments that other utilities around the country are making to serve their customers in terms of the types of technologies and materials used, expected useful life, and costs and benefits. Under the traditional approach to utility ratemaking in Massachusetts, utilities recover the costs of infrastructure investments only after the investments are made and there is often a considerable lag between the time expenditures are made and costs are recovered from customers. Although some commentators have maintained that regulatory lag provides discipline for utilities in the management of their assets, when utilities make investments that are not supported by current revenues, they erode earnings and hinder the utility's opportunity to earn its allowed rate of return. Because regulatory lag impacts the financial performance of utilities, it also places pressure on utilities to limit investments when the utility must balance capital investment against earnings deflation. Accordingly, utilities will typically prioritize investments that maintain safe and reliable service over investments in innovation and grid modernization, because there is significant precedence that such investments will meet the standard of good utility practice, as compared to more innovative and novel grid modernization investments. Lastly, the erosion in earnings brought on by regulatory lag can also harm customers as financial investors may require a higher return to invest in the Company's bonds. This will result in increased rates to customers from higher bond rates. Thus, under the status quo regulatory framework, the pace of grid modernization may not be sufficient to meet the changing energy needs of customers both today and over the long term.

Enabling Investments in Grid Modernization

Each of the alternatives described below represents a viable change to the regulatory framework that will enhance the opportunity for utility innovation and investment in grid modernization and allow the Department to evaluate the benefits of

Menu Option 1: Expand Investment Caps Eligible for Recovery - Historic Test Year

Menu Option 1 builds from National Grid's approved electric capital investment recovery mechanism. The Department approved in National Grid's last electric rate case an annual recovery mechanism for in-service capital investments made by National Grid in a preceding calendar year. The Department approved this mechanism as a complement to decoupling. The amount that National Grid can recover is based upon a cap of $170 million of in-service investments in a given year. The Company's actual investments are reviewed annually by the Department in a proceeding in the year following the in-service year of the investment. The Department review allows for investigation of the prudence of the investments in an adjudicatory proceeding. This approach maintains the historic test year method for rate recovery and, as such, does not eliminate the effects of regulatory lag.

Menu Option 1 would allow a utility with this mechanism in place to request an increase to its capital investment budget cap outside of a base rate proceeding for additional investment that a utility has determined is necessary to modernize the grid while maintaining safe, reliable service. Under this approach, the utility would have the ability to request an increase to the capital investment budget established during its most recent base rate proceeding for Department review and approval. The scope of this review would be limited to the Company's broad rationale for increasing its capital investment budget . So long as the request is consistent with the goals of modernizing the grid, the Department would not need to conduct a full adjudicatory proceeding to review the request to increase the capital investment budget. Rather, the Department would undertake a thorough review of the actual investments, projects and costs at the time that the utility requests recovery for in-service investment in the following year. Thus, the utility maintains the full risk of cost disallowance if its investments are deemed imprudent even though the Department may have approved an increased capital investment budget at the beginning of the year.

There are many strengths to this approach. First, the approach provides flexibility regarding the level of investment that a utility deems necessary in any given year. A utility can elect to use its entire budget or can fall back to a lower level if appropriate. Second, the request can accommodate the effect of inflation on costs for equipment and manpower by allowing expansion of the capital investment budget. Third, the Department can determine the appropriate speed for modernization of the grid and improvements to safe, reliable service based upon the impacts to customers' bills from an expansion. Lastly, this approach speeds the modernization of the grid without the need for frequent rate cases yet maintains the full authority of the Department to investigate the prudence of the utility's investments.

The weakness of this approach is the potential for the utility's initial request to increase its capital investment budget to become bogged down in a lengthy regulatory proceeding with an uncertain timeline for receipt of a final decision from the Department. Even though all investments would be reviewed after the in-service date, the Department and intervenors may request additional time for investigation into the need and projects associated with the proposal to increase the capital investment budget. This may affect the timing of grid modernization investment while the proceeding remains ongoing and provide uncertainty to the utility in its planning process and in the implementation of its plan. Also, as noted above, this approach maintains the effects of regulatory lag on first year investment which will be recognized by the financial markets as noted above.

In principle, this menu option accords with the Utility Consensus model.

<u>Menu Option 2: Expand Menu Option 1 to Three Years - Historic Test Year</u>

A concern of regulators and customers may be path of investment necessary to modernize the grid. Although utilities must be cautious regarding forecasts too far in the future given the risk of uncertainty, expectations regarding investment levels and corresponding need over a few years would be far less uncertain. Technological changes and changes in customer use will not be as dramatic as could be possible over a longer timeframe. Thus, the utility can plan for a certain level of work using certain standards for modernizing the grid. Adaptation of the plan will occur annually as known facts reveal differences from the initial plan. However, the annual changes will be small adjustments, not major unforeseen changes. A three year period would be an appropriate length of time for a utility to present a fairly definite level of investment necessary for modernizing the grid while providing safe, reliable service to customers.

The regulatory request for approval would be identical to Menu Option 1, except the request would be for a three year period. Utilities would present grid modernization goals for the next three years along with a capital investment budget to meet these goals for each year of the plan. The Department would review the request in terms of meeting the twin goals of modernizing the grid while balancing concerns over bill impacts to customers. As in Menu Option 1, regulatory review should assess these facts quickly and the Department should reach a decision within a set period of time, since the review of the prudency of actual investments would occur in each year after the investment was made and delays at this stage would impact the Company's ability to implement its plan.

This menu option maintains the strengths from the first option: Utility can flex the level of investment deemed necessary in any year; accommodation for inflation on costs for equipment and manpower; Department can determine the appropriate speed for modernization of the grid considering bill impacts to customers; authority of the Department and right of intervenors to question the prudence of investment is maintained. In addition, the ability of the Department to determine a multi-year level of investment that modernizes the grid provides greater real transparency regarding the utility's expected investment levels and goals for the investment.

The weakness of this approach is the potential for the utility's initial request to increase its investment budget to become bogged down in a lengthy regulatory proceeding with an uncertain timeline for final decision. Even though all investments would be reviewed after they are placed in-service, the Department and intervenors may request additional time for investigation into the need and projects associated with the proposal for increased investment. This may affect the timing of grid modernization investment while the proceeding remains ongoing. Also, as noted above, this approach maintains the effects of regulatory lag on first year investment which will be recognized by the financial markets, increasing costs to customers.

In principle, this menu option accords with the Utility Consensus model.

Menu Option 3: Change from Historic Test Year Review to Forecast Rate Year Review

The next menu option is a forecast rate year method for rate-setting. In Menu Options 1 and 2, the utility's capital investment plan goals and total investment are forecasted but recovery occurs after investment is in service as a result of a separate Department review of the investments. Menu Option 3 introduces the concept of forecasting all costs that the Company anticipates incurring during the year in which rates become effective. The forecasted items would include changes in revenue, investment plan, operations and maintenance expense and administrative and general expense. This approach uses the historic test year as a base from which the forecast is created along with any adjustments for known changes in future costs significantly above or below inflation, except for the investment plan which is more specific to projects and programs.

The forecasted rate year approach would continue with an ongoing capital recovery mechanism for utilities with decoupled rates as described in Options 1 and 2. Maintaining this approach in the years after the rate year would provide all the benefits enumerated before for those options.

A forecasted rate year approach to cost of service provides utilities with greater incentive to invest in modernizing the grid because it would align the cost of service with the time period in which the costs would be incurred. As such, the revenues would be set to match expected costs, as approved after review by the Department, in the year of incurrence instead of costs incurred two years earlier. Modernizing the grid implies that additional investment may be necessary than what has occurred in the past. In addition, the availability of greater amounts of information would cause an increase in O&M costs to process and analyze the data for use in operating the distribution grid and providing service to customers. A benefit from use of a forecast rate year is the alignment of future plans to modernize the grid with the rates necessary to recover the costs. Department approval of the forecast rate year would align the company's future operations and investments in the rate year with the goals of the state energy plan that requires a modern grid. A future rate year does not eliminate the risk that the company must perform according to the approved plan and manage costs in a way to deliver the approved plan.

The current source of costs and revenues for rate case filings in Massachusetts is a recent historic test year adjusted for known and measurable changes, such as union contracts. Historical costs and revenues are often not a good indication of what costs and revenues will actually be at some future point in time, especially in the context of grid modernization which by its very definition is not historic. For Massachusetts, preparation for a rate case does not even begin until a historic test year is complete. Preparation of the case takes time, typically up to five months before filing. Due to recent statutory changes, a filing that occurs five months after the end of the historic test year is now reviewed by the Department over a ten month suspension period. By the time an order is issued and rates are in effect, the data upon which the rates are determined will be fifteen to twenty- seven months old. The staleness of the data results in attrition of the ability of the utility to earn its allowed return on equity approved in the case from the effective date, which has a negative impact on utility investment decisions.

The future grid will do more than the present grid to enable renewable energy, distributed generation and customer demand response, among other goals. Assuming that a modern grid is justified as used and useful and cost beneficial for delivery and distributed generation customers, historic levels of investment in utility infrastructure are not representative of the levels of investment that will be necessary to modernize the grid for the future. Decoupling fixes the revenue level which does not allow any increase from growth to pay for additional expenses to modernize the grid. Continuation of a capital recovery mechanism for decoupled utilities after the initial rate year allows for the potential deferral of rate cases as it would provide for recovery of ongoing investment to modernize the grid as outlined earlier.

A forecasted rate year takes the inputs from the historic test year and inflates those values by inflation or actual forecasts of costs, e.g., capital investment plans, to derive the revenues necessary to run the utility in a forward-looking rate year. All elements of the forward-looking rate year including inflation in O&M expenses, forecasts of revenues and forecasts of capital investment are carefully reviewed by the regulator and intervenors to the case. The utility is required to justify the reasons for increases in costs in the future such as the rate of inflation for O&M costs or investment costs for projects and programs in the investment plan.

The drawback to a forward rate year cost of service approach is the uncertainty created among all stakeholders regarding a significant change in the regulatory model. This uncertainty may result in prolonged adjudication of any proceeding in which the Department considers institution of forecast rate years as an approach. However, any prolonged delay in receiving a final decision from the Department may lessen the speed of further grid modernization investments given the uncertainty in the regulatory model.

Menu Option 4: Multi-year Rate Plans with Forecasted Rate Years

The final menu option is a multi- year forecasted rate plan. This approach takes the same form as Menu Option 3 with a forecasted rate year based upon an historic test year and forecasts of known changes such as capital investment. However, it would extend the plan for a number of years, usually three to five years. The benefit from multi- year plans, particularly when considering grid modernization, is that the utility's capital

investment plan can be reviewed and approved for a number of years with recognition of and accountability for the goals of the plan. Also, multi-year rate plans improve the efficiency of regulation, particularly for utilities with decoupled rates, as they will not need to file multiple rate cases to acquire the revenues necessary to provide safe and reliable service through a modern grid. The length of the plan should be reasonable but not too long, as experience has shown that long multi-year rate plans tend to forecast the needs in the latter half of the plans poorly. A three year period provides the transparent view of the utility's plans going forward while avoiding the risks from unforeseen changes that affect utility plans in future years.

Conclusion and Recommendation

Each of the options discussed above will enable utilities to make increased investments in grid modernization. National Grid recognizes that some represent bigger changes to the present regulatory construct than others, and require careful thought. As a first step, National Grid recommends that the Department allow it to make a grid modernization proposal consistent with Option 1 (pre-approval of an increased spending amount under its capital investment recovery mechanism, subject to an after the fact prudency review) in order to begin the journey of grid modernization, while the more far reaching proposals are considered. This small step in regulation will enable a giant leap for grid modernization.

Utility of the Future, Today

Authors: Members of Clean Energy Caucus, ISO New England and National Grid

Summary of Regulatory Model

Regulatory Elements:	Description:
Customer-facing, grid-facing or both	Both. While the Utility of the Future Framework was developed in response to the Department's Notice of Inquiry in D.P.U. 12-76 concerning the modernization of the electric grid, the framework should apply to all utility spending and not just spending associated with grid modernization investments and business practices.
Rationale for, or summary of, model	To encourage cost-effective grid modernization (GM) efforts, this regulatory model utilizes forward-looking and performance-based ratemaking elements. The process is initiated by the utility filing a forecasted, multi-year rate case that includes its proposed capital and operational expenditures including those associated with its GM plan. The DPU reviews and approves (1) the investment plan, of which GM is a part, if found to be cost-effective as defined herein, and (2) the resulting rates if found to be just and reasonable for providing safe, reliable service to customers. Based on the utility's implementation plan, an annual schedule of base rates is developed to recover approved capital and operational expenditures. During an annual review process, variances between planned and actual capital expenditures must be explained by the utility. A Capital Reconciliation Mechanism is used to adjust annual base rates on a going-forward basis to reflect DPU-approved variances in capital spending. Operational costs reflected in base rates are adjusted annually using an approved, forward-looking formula that considers inflation adjusted for productivity. Base rates are also adjusted annually pursuant to DPU review of performance, including service quality metrics that give utilities the incentive to improve performance and service quality.
Regulatory Oversight:	
Utility pre-implementation filing requirement	Elements of the capital investment plan filed by the utility with the DPU should include: a description of the purpose and scope of the plan, an explanation of how the plan is consistent with the GM values and objectives adopted by the DPU as a result of the Docket 12-76 Final Report, itemized benefits and costs with supporting documentation, benefit-cost analysis, cost recovery proposal, class ratepayer impact analysis, and implementation plan. If the capital investment plan includes deployment of more advanced metering that accommodates time-based rates, an analysis, and if appropriate, a proposal for time-varying rates for basic service that addresses each function of service (e.g., customer, distribution, transmission, generation), including a plan for low-income customer protection, should be filed as well.
Regulatory review and approval of filing	The DPU reviews and holds a proceeding on the utility's filing.

	Standard administrative procedures for a rate case are followed.
Utility request for pre-approved GM budgets	As previously described, the utility would file a forecasted, multi-year rate case for DPU review and approval that includes its proposed capital and operational expenditures including those associated with its GM plan.
Stakeholder input	Each utility should be required to present to stakeholders the critical aspects of its capital investment plan and the plan's focus on GM goals *before* filing the plan with the DPU. Utilities should be encouraged to modify plans based on stakeholder comments or proposals. The capital investment plan filing by the utility should include a description of the stakeholder input process and the value it provided to the utility.
Utility reporting requirements	Utility reports annually on progress implementing its capital expenditure plan, which includes GM. The Capital Reconciliation Mechanism is adjusted annually to reflect DPU-approved variances in capital spending. Base rates are adjusted annually pursuant to DPU review of utility performance and service quality metrics.
Cost-Effectiveness:	
Explicit, public cost-effectiveness requirement	Before the start of each plan period, the utility files a rate case in which it must present a "business case" that would include a description of each quantifiable cost and benefit, the associated net present value, and the key assumptions that went into each value, along with a sensitivity analysis. Any costs and benefits of the proposed investment that the proponent believes should be considered but which could not be reasonably quantified should also be presented and explained. Generally, the proposed approach would be considered cost-effective when the benefits of the business case exceed the costs, and is consistent with the GM values and objectives adopted by the DPU as a result of the Docket 12-76 Final Report.
Internal analysis by utility	Any relevant analyses by the utility are discoverable.
Ratemaking and Cost Recovery:	
General ratemaking (historic, future test years)	Future test (rate) years with performance-based ratemaking element.
Frequency of rate cases	The duration of the plan for which the forecasted, multi-year schedule of base rates would be in effect is proposed by the utility. A Capital Reconciliation Mechanism is used to adjust annual base rates on a going-forward basis to reflect DPU-approved variances in capital spending. Base rates are also adjusted annually pursuant to DPU review of utility performance and service quality metrics.
Cost recovery (e.g., base rates, trackers)	Base rates are used to recover forecasted capital (including depreciation and return components) and operational expenditures. A Capital Reconciliation Mechanism is used to adjust annual base rates on a going-forward basis to reflect DPU-approved variances in annual capital expenditures. The Capital Reconciliation Mechanism is primarily intended to address timing of investment that takes place over multiple years. Total capital expenditures recovered in base rates are not expected to exceed what was presented up front and was analyzed for cost effectiveness, though the utility may

	petition the DPU to consider using the Capital Reconciliation Mechanism to decrease or increase base rates to address unusual circumstances. Operational costs are recovered through base rates set as a result of the multi-year rate case filing in which the costs are adjusted over the term of the plan based on a formula that takes into account the rate of inflation adjusted for productivity gains, with annual adjustments pursuant to DPU review of utility performance and service quality metrics.
Cost allocation (among customer classes)	Traditional cost allocation principles apply.
Cost assignment (e.g., to third party)	Limited third party assignment based on traditional cost causation principles.
Rate design	Time-varying rates for all customer classes based on time-specific marginal costs for each function of service (e.g., customer, distribution, transmission, generation) should be considered if the plan includes the installation of time-based metering. The utility should evaluate the range of rate design options, and recommend the appropriate option(s) for each customer class including whether the recommended rates should be an opt-in versus opt-out approach. Low-income customer rates should provide affordability and stability, but also should enable low-income customers to benefit from shifting consumption to lower-cost periods.
Utility incentives (e.g. ROE, rewards/penalties)	Standard/baseline ROE established according to pre-determined formula (e.g. Treasury + X%). Additional basis points of return tied to performance and service quality. ROE adjustment is symmetrical.
Performance Targets or Metrics:	
Role of performance targets	Give utilities incentives to improve performance and service quality given the cap on the regulated portion prices/revenues.
Performance targets that will be used	Performance targets and metrics are integral to utility capital plan and flow from its supporting business case. Performance targets and metrics should be designed around the most important, forward-looking assumptions that impact the business case of the proposed GM investment. Actual metrics can vary from utility to utility and should be offered by the utility in each rate case filing at the outset of each plan period.

2. Description of Regulatory Model

Executive Summary

To encourage cost-effective grid modernization (GM) efforts, this regulatory model utilizes forward-looking rate making with future test years and performance-based ratemaking. While the Utility of the Future Framework was developed in response to the Department's Notice of Inquiry in D.P.U. 12-76 concerning the modernization of the electric grid, the framework should apply to all utility spending and not just spending associated with grid modernization investments and business practices.

The regulatory process is initiated by the utility filing a multi-year, forward-looking revenue recovery plan (rate case) using a forecast for investment and O&M including costs associated with its GM program. The duration of the plan is proposed by the utility at the time of filing. The utility would also include its business case for the plan (filing elements described below). The DPU approves the plan and associated rates for cost recovery for those elements found to be cost-effective. Once the DPU approves the plan, an annual schedule of base rates recovering capital and O&M costs associated with the approved plan (adjusted for in-service assumptions and appropriate depreciation), is also approved. Investments approved by the DPU as part of the plan are deemed to be prudent and in the public interest, and return of and on authorized investments are reflected in customer bills going forward and reflect the planned timing of investments made each year.

Each year an annual review process is held in which the utility must report and explain to the DPU any variances between planned and actual capital expenditures. The difference in revenue requirements between planned and actual capital expenditures is reflected in a Capital Reconciliation Mechanism which is used to adjust future base rates, including carrying costs based on the utility's pre-tax weighted average cost of capital, to reflect DPU-approved variances in capital spending. Additionally, operational expenditures reflected in base rates are adjusted annually using an approved, forward-looking formula that considers the rate of inflation adjusted for productivity gains for the duration of the plan. Base rates are also adjusted annually pursuant to DPU review of performance and service quality metrics that give utilities the incentive to improve performance and service quality.

<u>Regulatory Oversight</u>

Elements of the capital investment plan filed by the utility with the DPU should include: a description of the purpose and scope of the plan, an explanation of how the plan is consistent with the GM values and objectives adopted by the DPU as a result of the Docket 12-76 Final Report, itemized benefits and costs with supporting documentation, benefit-cost analysis, cost recovery proposal, class ratepayer impact analysis, and a detailed implementation/deployment plan. If the grid modernization plan includes deployment of more advanced metering that accommodates time-based rates, an analysis, and if appropriate, a proposal for time-varying rates for each customer class that addresses each function of service (e.g., customer, distribution, transmission, generation), including a plan for low-income customer protection, should be filed as well. The plan is approved by the DPU if found to be cost effective.

Each utility should be required to present to stakeholders the critical aspects of its capital investment plan *before* filing the plan with the DPU. Utilities should be encouraged to modify plans based on stakeholder comments or proposals. The capital investment plan filing by the utility should include a description of the stakeholder input process and the value it provided to the utility. The DPU will review the capital investment plan as well as the other elements of the utility's filing during the course of the rate proceeding. Standard administrative procedures for a rate case are followed.

Each year an annual review process is held in which the utility must report and explain to the DPU any variances between planned and actual capital expenditures. DPU-approved variances in capital spending are reflected in a Capital Reconciliation Mechanism, which adjusts base rates going forward.

Base rates are also adjusted annually pursuant to DPU review of utility performance and service quality metrics.

Cost Effectiveness

Before the start of each plan period, the utility files a rate case in which it must present a "business case" that would include a description of each quantifiable cost and benefit, the associated net present value, and the key assumptions that went into each value, along with a sensitivity analysis. Any costs and benefits of the proposed investment that the proponent believed should be considered but which could not be reasonably quantified should also be presented and explained. Generally, the proposed approach would be considered cost-effective when the benefits of the business case exceed the costs, and is consistent with the GM values and objectives adopted by the DPU as a result of the Docket 12-76 Final Report.

Ratemaking & Cost Recovery

Projected investment costs (depreciation and return on net plant in-service components) enter base rates beginning in the initial year of the plan and reflect the planned timing of investments over the approved plan timeline. Each year an annual review process is held in which the utility must report and explain to the DPU any variances between planned and actual capital expenditures. The difference in revenue requirements between planned and actual capital expenditures is reflected in a Capital Reconciliation Mechanism, which is used to adjust future annual base rates, including carrying costs based on the utility's approved pre-tax weighted average cost of capital, to reflect DPU-approved variances in capital spending. Operational expenditures are recovered through base rates that are set at the time of approval of the utility's multi-year rate case. This portion of base rates is then adjusted on an annual basis over the term of the plan based upon a formula that takes into account the rate of inflation adjusted for productivity gains. Further, base rates are adjusted annually pursuant to DPU review of utility performance and service quality metrics.

The allowed return on equity (ROE), used to determine the return component of cost recovery, is initially based on the utility's standard ROE as approved by the DPU in the forward-looking rate plan, but would be adjusted in subsequent years based on demonstrated performance. The standard ROE represents satisfactory or standard performance, akin to the status quo. The ROE can be increased or decreased annually according to performance under the approved metrics. The adjusted ROE would be applied to the utility's entire net plant in-service to determine the base rates for the next year. An example of how the ROE could be adjusted is as follows:

Performance Level	Add/Subtract	Allowed ROE*
Poor	(50 bps)	X - 0.50
Below Standard	(25 bps)	X - 0.25
Standard	0	X
Above Standard	25 bps	X + 0.25
Exceptional	50 bps	X + 0.50

Note that this table of adjustments is illustrative.

* X = Standard Return On Equity

The actual increments/decrements applied to the utility's standard ROE for superior/poor performance would be determined based on the premise that the increments/decrements must give the utility sufficient financial incentives to achieve GM plan success.

Base rates

As mentioned above, base rates are set initially reflecting approved, planned capital and operational expenditures. Base rates are then adjusted annually to reflect DPU-approved variances between actual and planned capital expenditures using a Capital Reconciliation Mechanism. Total capital expenditures recovered in base rates are not expected to exceed what was approved by the DPU based on the information presented up front by the utility, which was analyzed for cost effectiveness. The Capital Reconciliation Mechanism is primarily intended to address timing of investment that takes place over multiple years, though the utility may petition the DPU to consider using the Capital Reconciliation Mechanism to decrease or increase base rates to address unusual circumstances. Further, base rates are adjusted each year to reflect utility performance relative to DPU-approved performance and service quality metrics.

Time Varying Rates, Rate Design:

Time-varying rates based on time-specific marginal costs for each function of service (e.g., customer, distribution, transmission, and generation) should be considered for all customer classes. The utility should evaluate the range of rate design options (e.g., PTR, CPP, VPP, RTP, etc.) as part of the utility's general rate proceeding, or be considered in a separate, targeted rate design proceeding, and recommend the appropriate option(s) for each customer class including whether the recommended rates should be an opt-in versus opt-out approach. Low-income customer rates should provide affordability and stability, but also should enable low-income customers to benefit from shifting consumption to lower-cost periods.

Performance Targets or Metrics

Utilities must be given incentives to improve performance and service quality given the forward-looking cap on regulated revenues.

Generally, the performance targets and metrics would be designed around the most important, forward-looking assumptions that impact the business case of the proposed GM investment. For example, if the GM investment is dependent upon a certain percentage of its customers adopting demand response, distributed generation, or energy storage so that benefits outweigh costs, then a performance target/metric around that customer adoption rate would be formulated and linked to the increments/decrements around the baseline ROE for superior/poor performance with respect to those metrics. Also, service quality/system reliability metrics – e.g., SAIDI, SAIFI, CKAIDI, and CKAIFI – should be modified, if appropriate, to reflect the expected improved service quality resulting from GM investments and should be similarly linked to the increments/decrements around the baseline ROE for superior/poor performance with respect to those metrics. Actual metrics can vary from utility to utility and should be offered by the utility in each rate case filing at the outset of each plan period.

3. Strengths and Weaknesses of the Regulatory Model (compared to status quo)

Strengths

Since the primary mission of a distribution utility – the provision of safe and reliable service – is currently being accomplished without substantial GM, and since many of the incremental benefits of GM investments tend to accrue to others (i.e., customers, energy service and technology providers, and society in general) and not the utility, the risk of disallowance under traditional ratemaking practices (e.g., historical test-year approaches) discourages utilities from pursuing GM investments. This model addresses this shortcoming by requiring the utility to analyze GM investments from a broader point of view and providing alignment on the GM goals between regulators, stakeholders, customers and the utility. Perhaps most notably this model adds an improvement to performance measurement to traditional cost recovery. The accountability of performance is offered as a counter-weight to the comfort afforded utilities from pre-approval and concurrent capital cost recovery through base rates. In addition, regular reporting of performance can inform regulators and stakeholders of the true functional value of GM investment over time. GM investment is continually evolving which translates to uncertainty at the time GM plans are proposed. The ongoing reporting of performance can help alleviate uncertainty and build common understanding.

Weaknesses

Instead of reviewing the prudence of actual, booked costs, the focus is on reviewing forward-looking cost and risk assumptions in the benefit-cost analysis. This shifts the type of expertise needed to review GM plans. Assessing the reasonableness of cost projections and the connection to Docket 12-76 objectives becomes important because the prudence of investments authorized by the plan is presumed once a GM plan has been approved.

Summary of the Utility of the Future Framework

Since the primary mission of a distribution utility – the provision of safe and reliable service – is currently being accomplished without substantial grid modernization (GM), and since many of the incremental benefits of GM investments tend to accrue to others (i.e., customers, energy service and technology providers, and society in general) and not the utility, the risk of disallowance under traditional ratemaking practices (e.g., historical test-year approaches) discourages utilities from pursuing GM investments. Yet GM promises to bring substantial net benefits to society including improved reliability, improved capacity utilization, reduced environmental costs, and increased customer choice. To address the fundamental shortcoming in the incentive structure of traditional utility ratemaking practice, which imposes a barrier to cost-effective GM, we propose that a new regulatory model be adopted by the DPU – one that requires the utility to analyze GM investments from a broader point of view, gives the utility a degree of certainty regarding GM cost-recovery before it makes GM investments, and evaluates and rewards good GM plan implementation and performance on an ongoing basis. The regulatory model that we believe will encourage cost-effective GM efforts must be forward looking with annual review of plan implementation.

Under the proposed regulatory framework, the utility would file a forecasted, multi-year rate case that includes its proposed capital and operational expenditures including those associated with its GM implementation plan. The overall length of the multi-year plan should be proposed by the utility in its filing considering potential changes in technology, demand for GM products worldwide, inflationary and productivity trends, uncertainties in critical assumptions, etc. The utility's GM plan would include the following elements:

- A description of the purpose and scope of the plan,
- An explanation of how the plan is consistent with the GM values and objectives adopted by the DPU as a result of the Docket 12-76 Final Report,
- A business case evaluating the benefits and costs of the plan, which itemizes all of the benefits and costs and provides supporting documentation,
- A cost recovery proposal including performance adjustment elements,
- A class ratepayer impact analysis, and
- An implementation plan.

If the grid modernization plan includes deployment of more advanced metering that accommodates time-based rates, an analysis, and if appropriate, a proposal for time-varying rates for each customer class that addresses each function of service (e.g., customer, distribution, transmission, generation), including a plan for low-income customer protection, should be filed as well. The utility should evaluate the range of rate design options, and recommend the appropriate option(s) for each customer class including whether the recommended rates should be an opt-in versus opt-out approach.

The DPU approves the GM plan if the benefits exceed the costs in the business case and the plan is found to provide safe, reliable service to customers while modernizing the grid. The DPU approves capital cost recovery if rates that result are just and reasonable. If the DPU approves the plan, capital cost recovery of the plan is approved. Investments approved by the DPU are deemed to be prudent and in the public interest, and return of and on authorized investments are reflected in customer bills incrementally as investments are made each year. The utility's GM plan would include an implementation plan that would allow the DPU to track the utility's progress toward completing its GM plan. This implementation plan would include a projection of the incremental investment that would be made by the utility over time to implement its approved GM plan. Recovery of capital and operational expenditures will be through base rates that reflects the expected timing of the investments over the plan years.

At the end of each plan year, the utility's progress relative to its implementation plan is reviewed by the DPU. The utility must report and explain to the DPU any variances between planned and actual capital expenditures. The difference in revenue requirements between planned and actual capital expenditures is reflected in a "Capital Reconciliation Mechanism," which is used to adjust future annual base rates, including carrying costs based on the utility's weighted average cost of capital, to reflect DPU-approved variances in capital spending. Operational expenditures are recovered through base rates that are set at the time of approval of the utility's multi-year rate case. This portion of base rates is then adjusted on an annual basis over the term of the plan based upon a formula that takes into account the rate of inflation adjusted for productivity gains. Further, base rates are adjusted annually pursuant to DPU review of utility performance and service quality metrics.

Perhaps most notably, this model adds a substantive element of performance measurement to traditional cost recovery. The accountability of performance is offered as a counter-weight to the comfort afforded utilities from pre-approval and concurrent capital cost recovery through base rates. Generally, the performance targets and metrics would be designed around the most important, forward-looking assumptions that impact the business case of the proposed GM investment. Actual performance targets and metrics can vary from utility to utility and should be offered by the utility in their GM plan. A utility that performs well relative to its performance metrics would have its return on equity (ROE) raised above its standard or baseline ROE – likewise, a utility that performs poorly relative to its performance metrics would have its ROE reduced below the baseline ROE. The performance reviews and performance-based rate adjustments described above would occur annually at the same time the utility's progress toward completion of its GM implementation plan is reviewed by the DPU.

In addition to reviewing the prudence of actual, booked costs as the basis for determining utility cost recovery, regulators under this model review forward-looking cost and risk assumptions in the benefit-cost analysis of a utility's GM plan as the basis for utility cost recovery. Also, it allows pre-determination that the utility's plan meets the GM goals of the State, customers, stakeholders and the utility. This shifts the type of expertise needed to review GM plans. Assessing the reasonableness of cost projections and the connection to Docket 12-76 objectives becomes important because the prudence of investments authorized by the plan is presumed once a GM plan has been approved. However, these changes are needed to encourage utilities in pursuing forward-looking GM investment that bring substantial net benefits to society.

Distribution Services Pricing

Author: National Grid, Clean Energy Caucus

Summary of Regulatory Model

Regulatory Elements:	Description:
Customer-facing, grid-facing or both	Both
Rationale for, or summary of, model	The growing implementation of customer-based energy technologies and local generation is transforming the distribution grid from one-way electricity delivery to an integration of load and generation (including, for purposes of this document, other distributed resources, e.g. storage, etc.). The distribution utility will need to manage this integration for the benefit of load and generation customers on the distribution grid. These services require pricing structures to recover appropriate levels of costs caused by load and generating customers and compensate load and generating customers for services provided to the grid, through appropriate economic signals so that customers can take maximum advantage of these technologies through forms of demand or generation response in order to lower costs of the distribution grid.
Regulatory Oversight:	
Utility pre-implementation filing requirement	File proposal and implementation plan for approval.
Regulatory review and approval of filing	Yes. DPU review and approval of a utility proposal for changes to distribution pricing would occur in the context of an adjudicatory proceeding with set time frames for review and receipt of a final order to enable timely and efficient implementation of approved changes.
Utility request for pre-approved GM budgets	Maybe: Depends on need for new technology and any other costs associated with implementation
Stakeholder input	Yes. Interested stakeholders can input during the DPU adjudicatory proceeding. The utility would conduct outreach activities prior to filing, as appropriate, to inform stakeholders and solicit feedback on potential new service offerings by the utility.
Utility reporting requirements	Determined during DPU proceeding, if necessary.
Cost-Effectiveness:	
Explicit, public cost-effectiveness requirement	If additional utility investment and/or costs are involved, business case analysis described in Chapter 7 would apply. Otherwise, none.
Internal analysis by utility	Any relevant analyses by the utility are discoverable.
Ratemaking and Cost Recovery:	
General ratemaking (historic, future test years)	Historic usage and customer information and/or forecast year information would be used in the rate design process.
Frequency of rate cases	As necessary, present rules apply.
Cost recovery (e.g., base rates, trackers)	As necessary if investment or costs incurred to engage customers or implement new prices.
Cost allocation (among customer classes)	Allocating costs on based on cost causation, fairness and equitable responsibility principles while providing

	economically efficient price signals would be applied and would be addressed in the context of a DPU proceeding.[77]
Cost assignment (e.g., to third party)	Limited third party assignment based on traditional cost causation principles.
Rate design	This would be a rate design (pricing) filing. Rate design principles related to sending economically efficient price signals based on underlying costs would apply.[78]
Utility incentives (e.g. ROE, rewards/penalties)	Not applicable
Performance Targets or Metrics:	
Role of performance targets	Not applicable
Performance targets that will be used	Not applicable

2. Description of Regulatory Model

Executive Summary

The future of the distribution utility is evolving towards the integration of load and generation for the benefit of customers receiving deliveries and customers with generation behind or at the meter. Current cost recovery and prices assumes all customers receive deliveries of kWh and that one-way power flow is the single reason for the distribution grid. However, the industry is changing with renewed investment and State policy support for local, renewable generation, combined heat and power generation, storage, microgrids (with capability to intentionally island from the rest of the grid as described in Chapter 3, Outcome 1) and electric vehicles at customer locations or stand-alone generation. The challenge for the distribution utility is mastering the integration of customer load and customer generation at the local level to provide low cost, safe and reliable delivery of electricity to customers, among customers and to markets.

Distribution systems are built to meet peak demands on each feeder and substation while managing the stability of the system. Maintaining stability and reliability of the system in this integrated world provides the opportunity to test and introduce new concepts regarding use of distributed resources, such as customer load, generation or storage to provide that stability, if possible. In addition, customer load and generation may create costs on the grid that must be managed and paid for under the concept of cost causation, across the system, as a group or as a customer . Modernization of the distribution grid will lead to improvements in knowledge regarding capability of the system to integrate load and generation; may contribute to improved efficiency in operation of the grid and capital investment; and may facilitate promotion of renewable and other types of distributed generation.

The Commonwealth of Massachusetts has the opportunity to undertake an effort to design distribution pricing for the future and lead the industry in this effort. These designs would allow customers to pay for the level of service specifically requested by customers instead of socializing the costs across all remaining customers (or use). At the same time, customers with generation or stand-alone generation

[77] One guide to pricing for these services will be to consider methods to maintain affordability of the total electric bill for low income customers.

[78] See Footnote 1.

may realize opportunities to provide services to the distribution utility by offering their demand response, energy efficiency, generation output, VAR support[79] and/or other services to allow deferral of investments by the utility that may be necessary to resolve short or long term reliability or stability issues on specific areas of the grid. New designs could make transparent the short or long term benefits provided to the utility to promote certain technology or opportunity while clearly designing the ongoing cost responsibility for connection to the distribution grid. New designs can provide incentives for customers to embrace opportunities that provide savings in the costs to operate the distribution grid over the long-term while ensuring fair recovery of costs from all connecting customers. Further, prices should be designed to send economically efficient price signals to bring customer consumption and production decisions into alignment, to inform customer investment choices regarding energy use, storage, or production, and to increase the productivity of the electric system.

Three examples are offered for explanation of the potential of this distribution services pricing model. The Department recognizes the need to provide larger industrial customers a price for their demand for KVA in excess of their KW demands. Large KVA demands create voltage issues at the local level and result in a system built to meet the KVA demands which are higher than the KW demands. Demand pricing on rates for larger commercial/industrial customers charge large customers if the customer demands a large amount of KVA relative to their KW demand. Customers have an economic incentive to install their own equipment to serve their KVA needs if doing so is less expensive than the Company's charges. This rate design internalizes to the customer the economics of the specific costs they were causing on the system.

Another example is National Grid's Second Feeder Service offering. Customers can request reservation of capacity on a second feeder in order to obtain immediate switch of service to the second feeder in the event of an outage on the first feeder. The customer pays for this reserved capacity every month as a capacity charge. Second Feeder Service is a form of insurance that capacity is always available for the customer except during emergency situations.

The last example is the Company's non-wires alternative Pilot in Brockton. In that pilot, National Grid provided a credit to customers for reducing their demand when called by National Grid to off-load the Belmont St. substation to provide National Grid the time to properly engineer, permit, and construct an expansion at the substation. Customers providing demand response, or generation, may allow a utility the opportunity to defer investment by lowering demand on the system during critical periods and assisting the utility in providing reliable and stable service to customers in the area. Customers who participated in this pilot saved money on electricity by lowering peak consumption when called and receiving a credit for that reduction in their peak load requirements.

These examples show that when charged their costs for services, customers can compare economic alternatives. and the distribution company can compensate customers with resources for the opportunity to use those options to maintain reliable, stable service to customers. In addition, the

[79] As stated in Chapter 3 (under Outcome 2), "Future applications [of Integrated Volt/VAR Control] may also incorporate distributed solar photovoltaic (PV) cells and other resources through the use of controllable inverters for VAR support."

offerings provide revenues to the Company to offset the costs of the services described above in the event the services are necessary while attempting to ensure that lowest cost alternatives are utilized when proven to be effective. Lastly, the Brockton pilot is a potential framework for providing value to customers who make available their resources/capabilities in a manner that lowers distribution costs to serve customers over a period of time.

The distribution grid is the area of the electric system that has the greatest effect on daily reliable service to customers. Thus, it is important to allow the design of the grid to provide reliable service. At present, the approach to cost recovery does not recognize a future that is about connections and capability, not simply delivery. Some, but not all, potential design characteristics could be considered:

1. Size of customer (kWh range, demand (kW or kVa), service amp level, requested service level);
2. Wheeling capacity requested;
3. Requested level of assured capacity or voltage(e.g., Second Feeder Service) and/or capabilities to intentionally island from the grid in microgrid mode;
4. Discounts would be available to local generation that allows physical assurance that demands will be reduced from the distribution grid;
5. Time varying pricing to encourage or schedule customer access to the Distribution grid that provides the reliability benefit to the grid. In this manner, customers can perform maintenance during low cost periods or take advantage of economic pricing from the market;
6. Power quality management services (e.g., management of excess voltage swings from either customer motors/machines or customer generation that flows onto the distribution grid; and/or services from the generation customer to the grid such as VAR support through controllable inverters); or
7. Rebates or lower costs for demand management or generation dispatch.

Regulatory Oversight

A proposed rate design can be filed as a component of a rate case, a proposal for metering systems or independently. Utilities would file a proposal once they determine a valid business case for the new price offering (rate design). The filing would include reasoning and analysis for the offering accompanied by a presentation of benefits to customers.

An alternative approach would be for the DPU to open an investigation into potential rate designs and their benefits/costs from implementation, either as part of a TVR proceeding or separately.

A change in rate design may require time for customers to comprehend the change. The principle of rate continuity may require a phase-in period for those customers receiving full distribution service.

Stakeholders would provide input to the filing by intervening in the adjudicatory proceeding before the DPU. In this way, stakeholders would be entitled to file formal comments and briefs, and all other privileges afforded to interveners for consideration in the Department's Order prior to implementation. The utility would conduct outreach activities prior to filing, as appropriate, to inform stakeholders and solicit feedback on potential new service offerings by the utility.

Also, a utility (utilities) and stakeholders may come to agreement on a proposal which becomes a settlement filed at the Department for its review.

Cost Effectiveness

If additional utility investment and/or costs are involved, business case analysis described in Chapter 7 would apply. Otherwise, none. In addition, the price structure would be designed on the underlying cost to deliver the service to requesting customers, and to promote economic efficiency.

Ratemaking & Cost Recovery

Any pricing proposal would demonstrate the fairness and equity of the new prices through analytical review of cost causation. Where benefits accrue to individual customers, any incremental costs would be paid for by customers on the proposed service offering. All customers would be responsible for any credits to customers for demand response or generation dispatch/availability as these efforts allow total reduction in costs to serve customers.

Performance Targets or Metrics

These are not foreseen as part of this model. However, any request for metrics or targets would be discussed during a proceeding before the Department.

3. Strengths and Weaknesses of the Regulatory Model

Strengths

- The model provides the opportunity to recognize the additional services provided by the distribution utility and charge the appropriate customers for those services.
- The model also provides the opportunity to recognize the services that distributed resources may provide to the system and to compensate the distributed resources appropriately.
- It minimizes cross-subsidies that will occur if these new service offerings or requirements are not recognized as a new service and charged appropriately.
- Provides economic basis for customers to determine whether utility provided service is more economic that own provision of service or third party provision.
- Provides the opportunity through physical assurance requirements to ensure the value claimed by local generation in terms of distribution savings by lowering the need for capacity.

Weaknesses

- The ability to change the present distribution rate structures to reflect cost causation may take a period of time due to rate continuity considerations.
- Concerns regarding incentives for energy efficiency in present rate structures will need to be understood as changes in rate structures are evaluated.

Regulatory Approval for Time Varying Rates and Direct Load Control

Author: National Grid

Summary of Regulatory Model

Regulatory Elements:	Description:
Rationale for, Summary of, Model	Receive approval for plan to roll-out of new product opportunities (rate designs) to assist customers in managing their energy use
Utility pre-implementation filing requirement	File implementation plan for approval
Regulatory review and approval of filing	Yes
Stakeholder input to filing	Yes, during the regulatory proceeding
Utility request for pre-approved budgets for GM measures	Maybe: Depends on need for new technology, outreach efforts to customers
Explicit, public cost-effectiveness requirement	Yes
Utility reporting requirements	Determined during DPU proceeding, if necessary
Cost recovery mechanism (capital and O&M)	Yes, separate mechanism, forward looking
Cost allocation (among customer classes)	Determined as a part of regulatory proceeding
Cost assignment (e.g., to third party)	
Rate design	
Utility incentives (e.g. ROE, rewards/penalties)	
Performance targets or metrics	
Ratesetting (general rates)	Historic test year or forecast rate year method may apply
Frequency of rate cases	Present rules apply.
Comments/Major issues	Interaction of proposed rate design and wholesale commodity prices

Description of Regulatory Model

Summary

Rate design options may be filed for approval included as part of a rate case or apart from a formal rate case. Rate design options could be filed as part of a proposal to convert metering to advanced systems with greater capability to provide certain opportunities to customers. These rate options would be designed to be revenue neutral to approved rates on a class basis. The rate options could include Time-of-Use rates such as fixed period TOU, fixed period critical peak pricing (CPP), variable period CPP, hourly pricing of demand response credits for load control options, etc.

Regulatory process

A proposed rate design can be filed as a component of a rate case, a proposal for metering systems or independently. Utilities would file a proposal once they determine a valid business case for the rate design. The filing would include reasoning and analysis for the rate design accompanied by a presentation of benefits to customers.

An alternative approach would be for the DPU to open an investigation into potential rate designs and their benefits/costs from implementation.

Stakeholder input to filing

Stakeholders would provide input to the filing by intervening in the docket before the DPU. In this way, stakeholders would be entitled to file formal comments and briefs, and all other privileges afforded to interveners for consideration in the Department's Order prior to implementation.

Cost effectiveness

Utility proposals would need to include justification for the rate designs and associated costs for implementation, customer outreach and enabling technologies. A demonstration of benefit would be provided as part of the filing.

Utility reporting requirements

Reporting requirements may be determined as a result of utility proposals and DPU deliberations in the proceeding.

Cost recovery

Utilities may request recovery of costs associated with implementation of the rate design, outreach to customers and enabling technologies.

Utility incentives

Incentives would be addressed in the context of the DPU proceeding and be specific to the nature of the investment.

Comments/Major issues

New rate designs have to consider the interaction of the rate design with the costs as incurred and billed in the ISO-NE wholesale market. This interaction creates risks that must be considered during any investigation.

Summary Evaluation

Overarching Criteria:	
Ability to achieve Grid Mod Goals	Moderate
Feasibility; i.e., difficulty of implementation	Good
Timeframe for implementation and results	Good
Consistent with relevant statutes	Good
Timing & flexibility to address dynamic options	Good
Costs and Customer Concerns:	
Consumer protection - low-income	Good
Consumer protection - other residential	Good
Consumer protection - C&I	Good
Customer class cross-subsidy impacts	To be determined
Likely bill impacts	To be determined
Utility shareholder impacts	Good
Address risks - to customers and to utility	Good
General Criteria:	
Empowerment (i.e., will it empower customers, utilities, vendors?)	Good
Enablement (i.e., will it result in a sufficient platform?)	Moderate
Support innovation by utilities	Moderate
Identify performance objectives, has transparent measurement and symmetrical rewards based on performance	Good
Provide process stability, lowers regulatory uncertainty	Moderate
Common value measurement model (e.g., business case, NPV to consumers, society)	Good
Risk - to different parties	Good

New Technology Adoption

Author: Electricity Storage Association

Summary of Regulatory Model

Regulatory Elements:	**Description:**
Customer-facing, grid-facing, or both:	Both
Rationale for, Summary of, Model:	DPU regulatory frameworks should encourage demonstration of emerging technologies for grid modernization (e.g., electricity storage), without requiring burdensome regulatory processes. In many cases, new technologies are introduced by startup companies that do not have the flexible capital required to survive a drawn-out regulatory process. A minimal level of investment is needed in these technologies for deployment and testing, in order to understand the benefits of wide-scale integration. The regulatory treatment will change as the technology moves from emerging to established, and as the level of utility investment increases. The regulatory process for the adoption of new technologies should occur in three phases: *Phase 1*: Utilities should have a small budget to be determined by the utilities and DPU (e.g., approximately $50 million), included in the rate base, which is devoted specifically to the pilot deployment of new technologies. These deployments should be fast-tracked to the field without regulatory hurdles. *Phase 2*: Once a technology has been tested on the system, and a utility wants to expand the use of that technology, a more thorough regulatory proceeding should be adopted that includes cost-effectiveness analysis, utility reporting requirements and a cost-recovery mechanism. *Phase 3*: After the technology has been utilized in the field for a sufficient period such that impacts are known, the technology should be considered as part of the class of regular transmission and distribution assets, and be eligible for funding by the utility through their annual budget for deployment without regulatory proceedings. Classification of technologies in each phase should be determined by the total amount of capital being put toward a given project with limits for a project within each phase.
Regulatory Oversight:	
Utility pre-implementation filing requirement:	Phase 2 only.
Regulatory review and approval of filing:	Phase 2 only.
Stakeholder input to filing:	No.
Utility request for pre-approved GM budgets:	Yes, all phases.
Explicit, public cost-effectiveness requirement:	Phase 2 only.
Utility reporting requirements:	Phase 2 and 3.
Ratemaking and Cost Recovery:	
Cost recovery mechanism (capital and O&M):	Yes, all phases.
Cost allocation (among customer classes):	These would be addressed in the context of the DPU proceeding, but utilities should be able to recover the costs at all stages.
Cost assignment (e.g., to third party):	
Rate design:	
Utility incentives (e.g., ROE, rewards, penalties):	
Performance targets or metrics:	
Rate setting (general rates):	Included in base rates in a general rate proceeding.
Frequency of rate cases:	
Comments/Major issues:	

Grid Modernization Advisory Council

Author: Environment Northeast

Summary of Regulatory Model

Regulatory Elements:	Description:
Customer-facing, grid-facing or both	Customer-facing or both
Rationale for, or summary of, model	Grid Modernization Advisory Council (GMAC) helps facilitate stakeholder input in the grid modernization planning process.
Regulatory Oversight:	
Utility pre-implementation filing requirement	Multi-year plans and budgets filed with DPU, process for mid-course corrections.
Regulatory review and approval of filing	Yes, in advance.
Utility request for pre-approved GM budgets	Yes, from DPU
Stakeholder input	Yes. The GMAC has a specific timeline for reviewing utility grid modernization plans in advance of specified filing deadlines. The GMC may submit its recommendations regarding the plans to the DPU.
Utility reporting requirements	Annual to DPU and GMAC
Cost-Effectiveness:	
Explicit, public cost-effectiveness requirement	Yes, analytical model to be approved by DPU, also reviewed in advance by GMAC
Internal analysis by utility	
Ratemaking and Cost Recovery:	
General ratemaking (historic, future test years)	
Frequency of rate cases	
Cost recovery (e.g., base rates, trackers)	Yes.
Cost allocation (among customer classes)	Cost-recovery would reflect the benefits to an individual consumer and the electric system as a whole.
Cost assignment (e.g., to third party)	
Rate design	
Utility incentives (e.g. ROE, rewards/penalties)	Yes, based on ROE with performance-based rewards and penalties determined by DPU
Performance Targets or Metrics:	
Role of performance targets	
Performance targets that will be used	The GMAC will provide recommendations to the DPU on performance targets and metrics.

Description of Regulatory Model

Executive Summary

In the spirit of fostering a robust discussion of regulatory options for grid modernization, ENE offers this Straw Proposal.[80] At the outset, we believe that participants in this Grid Modernization Proceeding should advance strategies in a balanced manner that encourages innovation while maximizing consumer and environmental benefits.

[80] ENE does not contend that this Straw Proposal represents the only reasonable path forward, but does encourage the participants to consider the elements contained herein in the context of this proceeding.

In order to encourage utilities to adopt innovative strategies and take reasonable risks that advance the Commonwealth's grid modernization goals, ENE's Straw Proposal would employ a Grid Modernization Advisory Council ("Advisory Council") to help the utilities shape their grid modernization decision-making. The Advisory Council would be composed of stakeholders representing a variety of interests and would be charged with providing input to utilities and the Department in a number of areas, including, but not limited to: (a) customer protection and education; (b) strategies to implement technology over time; (c) environmental benefits; and, (d) selection of the analytical cost benefit analysis framework. Annually, utilities must file a report with the Council and the DPU detailing expenditures to date and progress toward meeting DPU- defined performance goals.

The DPU will retain all of its regulatory roles, and the Advisory Council will serve as a facilitator for stakeholder input, working to resolve issues to the extent possible in a defined time period before utility proposals come before the Department.[81]

Regulatory Oversight

- The DPU requires utilities to develop and implement guidelines for meaningful and comparable consideration of non-wires alternatives as possible solutions to planning and reliability issues in distribution planning.[82] This process would include an analytical process for screening non-wires alternatives and the comparison of feasible wires and non-wires alternatives, and a framework within which such comparisons can be made.[83] The DPU would require these guidelines to be updated periodically based on experience in analyzing and implementing non-wires projects.[84]
- The DPU defines the scope of grid modernization and objectives, requirements, and/or necessary functionalities of the modern grid for the Commonwealth.
- Utilities submit multi-year plans and budgets to the DPU to achieve the defined grid modernization objectives. Utilities are able to receive advance approval for grid modernization investments. The process also would allow for mid-term course corrections.
- Stakeholders provide input to the multi-year plan and budget filing as part of the Grid Modernization Advisory Council. Early stakeholder input within a defined time period will expedite and reduce the cost of the DPU approval process prior to implementation.

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[81] Similar to the existing energy efficiency council model, stakeholder input will be facilitated by the GMAC, and stakeholders will have additional opportunity to comment when filings are made at the DPU.

[82] Non-wires alternatives may be defined as demand side management and distributed energy resources that leverage customer/third party resources and complement and improve operation of existing distribution systems, and that individually or in combination defer the need for upgrades to the distribution system.

[83] Proposed non-wires alternatives and other grid modernization strategies should be evaluated on their ability to meet the identified system needs; anticipated reliability of the alternatives; risks associated with each alternative; potential for synergies that meet multiple grid modernization objectives; operational complexity and flexibility; implementation issues; customer impacts; and other relevant factors.

[84] It may be instructive for the Steering Committee and DPU to review the proceedings of RI PUC Docket No. 4202, specifically with regard to the Standards for System Reliability Procurement Standards. See: http://www.ripuc.org/eventsactions/docket/4202-EERMC-RevSRP(3-1-11).pdf.

- The regulatory review process shall define reasonable review and approval timeframes to approve plans prior to implementation.

Cost Effectiveness

- There will be a threshold requirement for cost-effectiveness as well as an effort to maximize benefits and customer value.
- Financial analyses of proposed investments will be conducted to the extent feasible. The selection of analytical model(s) will be subject to DPU review and approval.
- The Grid Modernization Advisory Council shall provide input to the DPU and utilities on the selection of the analytical cost-benefit model.
- Selection or approval of grid modernization investments shall be informed by the considerations approved by the DPU and an evaluation of costs and benefits according to the approved analytical model.

Ratemaking & Cost Recovery

- Grid modernization investments eligible for cost-recovery are defined by the DPU and are consistent with the objectives, requirements, and functionalities of grid modernization as defined by the DPU.
- Utilities receive recovery for pre-approved costs, with reasonable guidelines for recovery/credit of over- and under-spending.
- Cost-recovery would reflect the benefits to an individual consumer and the electric system as a whole.
- Utilities will file appropriate proposals for rate design with all support and justification. The DPU will review, analyze and approve the final rate design for cost recovery.

Performance Targets or Metrics

Incentives would be based on ROE with performance-based rewards and penalties, as determined by the DPU. The GMAC will provide recommendations to the DPU on performance targets and metrics.

3. Strengths and Weaknesses of the Regulatory Model (compared to status quo)

Strengths

- The Grid Modernization Advisory Council ensures that diverse stakeholder interests- including business, technology, consumer, and environmental- are and continue to be represented throughout the grid modernization planning process.
- Use of a Grid Modernization Advisory Council will facilitate the DPU review and approval process to encourage timely grid modernization investments and limit lengthy, contested regulatory processes.
- The Grid Modernization Advisory Council can institutionalize the stakeholder engagement started in current DPU Grid Modernization process, including assuming responsibility for updating and revising the taxonomy and functionality matrices.
- This model requires utilities to develop and implement guidelines and an analytical framework for comparing the costs, benefits, and risks of various grid modernization strategies, including non-wires alternatives and traditional investments.

Weaknesses

- Introduction of Grid Modernization Advisory Council could be time consuming.
- If the Grid Modernization Advisory Council is not properly implemented, it could create delay and uncertainty.

  The costs of the Grid Modernization Advisory Council will need to be recovered.