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July 24, 2013

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: Investigation by the Department of Public Utilities Regarding Modernization of the Electric Grid, D.P.U. 12-76.

Dear Secretary Marini:

Enclosed for filing in the above-captioned matter please find the Initial Comments of the Office of the Attorney General, the Low Income Network, and the Associated Industries of Massachusetts. Please feel free to contact me if you have any questions. Thank you for your attention to this matter.

Sincerely,

/s/ Jamie Tosches

Jamie Tosches
Assistant Attorney General

Encl.

cc: Julie Westwater, Hearing Officer
Service List

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Investigation Modernization of the Electric
Grid

D.P.U. 12-76

**INITIAL COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL, THE LOW
INCOME NETWORK, AND THE ASSOCIATED INDUSTRIES OF MASSACHUSETTS**

I. INTRODUCTION

On October 2, 2012, the Department of Public Utilities (“Department”) issued an order opening an investigation into the modernization of the Massachusetts electric distribution system (“*October 2 Order*”).¹ As part of the investigation, the Department commissioned a stakeholder working group. The Department sought input from stakeholders on how to ensure that the Department’s policies facilitate the adoption of grid modernization technologies and practices over the short, medium, and long term.² On July 3, 2013, the working group, which was organized into a steering committee (“Steering Committee”), filed with the Department its final report, the *Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee* (“Final Report”).³ Pursuant to the Department’s notice requesting comment, the Office of the Attorney General (the “Attorney General’s Office”), the Low Income Network,⁴ and the Associated Industries of Massachusetts (“AIM”) hereby submit this Initial Comment on the Final Report.⁵

II. OVERVIEW

The Attorney General’s Office, the Low Income Network, and AIM welcome the opportunity to provide recommendations to the Department in this inquiry into grid modernization. In its *October 2 Order*, the Department stated that it seeks to “examine [its] policies to ensure that electric distribution companies adopt grid modernization technologies and practices in order to enhance the reliability of

¹ *Investigation into Modernization of the Electric Grid*, D.P.U. 12-76 (October 2, 2012) (“*October 2 Order*”).

² *Id.*, pp. 1, 6.

³ *Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee* (“*Final Report*”), D.P.U. 12-76 (July 3, 2013).

⁴ The Low Income Network is the network of community agencies that, *inter alia*, implement the low-income energy efficiency retrofit programs pursuant to the Green Communities Act.

⁵ These Initial Comments are consistent with the Steering Committee’s ground rules that allow signatories to the Final Report to provide comments on the report and supplemental information that are “[n]ot inconsistent with the positions taken by that signatory organization within the Final Report.” The ground rules are available at the following link:

<http://magrid.raabassociates.org/events.asp?type=typ>

electricity service, reduce electricity costs, and empower customers to adopt new electricity technologies and better manage their use of electricity.”⁶

The Department should put affordability, reliability, and the safety of electric service at the forefront of its policy on grid modernization. Affordability is a significant concern for Massachusetts’ customers who pay some of the highest rates in the nation. The Department’s policy should promote least-cost service and enhance the electric distribution companies’ (“EDC”) ability to meet their respective obligations to provide safe and reliable service.

The Final Report is a good first step to achieving the Department’s objectives outlined in its *October 2 Order*. The Final Report provides recommendations on relevant topics in Chapter 5, addresses two significant questions in Chapters 6 and 7: “How should the EDCs recover costs for grid modernization technologies and practices?”; and “How should the Department evaluate the cost effectiveness of them?”; and provides recommendations for next steps in Chapter 8.

However, the Final Report does not present specific evidence or a reasonable basis upon which to justify adoption of grid modernization policies that depart from the base rate case method of cost recovery or the Department’s precedent on reviewing the cost-effectiveness of investments. No stakeholder has put forth specific evidence to demonstrate that such a departure is necessary. To the contrary, the EDCs have already begun the grid modernization process through the automation of their distribution systems. Before the Department adopts new regulatory policies that significantly depart from the Department’s cost recovery and cost-effectiveness policies in place today, the Department should answer the following key questions within company-specific adjudicatory proceedings:

1. What additional technologies and investments are needed, if any, to achieve the outcomes and attributes identified in Chapter 3 of the Final Report for each EDC, in light of the progress that each EDC has made in upgrading and modernizing its distribution network?
2. What evidence and facts support the identified or desired benefits associated with the grid modernization investments and opportunities recommended by the various stakeholders in the Final Report?
3. What would it cost to achieve additional grid modernization technologies and programs that are incremental to those that are already installed or planned? What are the associated rate and bill impacts? Are there less costly means of achieving similar benefits?
4. What are the costs and benefits of installing advanced metering for the EDCs, in light of the current metering systems in place, including what amount of stranded costs would be associated with replacement of those systems?
5. What are the potential impacts on reliability of service for customers that could be delivered with incremental investments in the distribution system? What are the potential cost, and rate and bill impacts? At what point is reliability an individual customer responsibility?

⁶ *October 2 Order*, p. 1

6. What are the costs, benefits, and rate and bill impacts associated with adopting one or more of:
 - (a) the approaches to cost effectiveness recommended in Chapter 6 of the Final Report, and;
 - (b) the recommendations concerning changes in the current rate making policies in Chapter 7 of the Final Report?

Instead of embarking on individualized adjudicatory proceedings to evaluate policy options, the Department should adopt the measured and reasonable approach to cost recovery and cost-effectiveness that the Attorney General's Office and the Low Income Network have developed. The approach is reflected in the Enhanced Regulatory Model, as described in the Final Report.⁷ Given that the Enhanced Regulatory Model does not significantly depart from existing cost recovery and cost-effectiveness policies in place today, the Department can adopt the approach now, and without further investigation.

Under the Enhanced Regulatory Model, the EDCs will continue to be required to demonstrate within a base rate case proceeding that investments are prudent, used and useful, least cost, and that they have been appropriately allocated among rate classes.⁸ That process helps ensure affordable rates, and provides for a review of proposed rates and the bill impacts associated with those proposed rates. The Enhanced Regulatory Model enhances the base rate case model by recommending that the Department amend its Service Quality Guidelines to increase the reliability performance targets that the EDCs must meet on an annual basis in order to avoid penalties. This recommendation recognizes the potential for grid-facing investments to improve reliability.⁹ The EDCs would also file additional reports on their grid-facing plans and activities, which could then be implemented by the EDCs after stakeholder input, with actual costs and benefits subject to full review in a base rate case proceeding.

Additionally, the Enhanced Regulatory Model facilitates opt-in time varying rates ("TVR"), opt-in direct load control programs, and advanced metering proposals by providing an additional layer of review. The model adds pre-approval proceedings requiring the EDCs to demonstrate that the costs and benefits of a direct load control program or a full metering roll-out provides customers net benefits and employs a cost-effectiveness test based on existing Department precedent. The cost of the programs would not be recovered until the EDC files a base rate case proceeding, in which the EDC would be held accountable for the costs and benefits it claimed in the pre-approval proceeding.

This measured approach makes sense given that there is still a good deal to learn from the American Recovery and Reinvestment Act ("ARRA") Smart Grid pilot projects and the Massachusetts

⁷ The Enhanced Regulatory Model is described in Chapter 6 of the Final Report, and it incorporates the recommended cost-effectiveness framework in Chapter 7. *See Final Report*, pp. 59-63 (describing the Enhanced Regulatory Model); *Id.*, pp. 75-79 (describing the recommended framework for evaluating cost-effectiveness framework).

⁸ However, National Grid has been authorized to recover some capital investment costs through a capital tracker. *See Massachusetts Electric Company, Nantucket Electric Company, d/b/a/ National Grid*, D.P.U. 09-39 (2009).

⁹ This is consistent with the Office of the Attorney General's recommendations in *Notice of Inquiring on Service Quality Standards*, D.P.U. 12-120.

smart grid pilots.¹⁰ Caution is advisable for a number of reasons. Grid modernization technologies are still developing and carry a risk of obsolescence with them. Requiring investments today without fully considering the results of these pilots will yield uncertain future benefits and potential stranded costs. Many technologies are not yet proven through wide-scale deployment to provide actual benefits, and in some cases, program benefits will hinge on customer engagement, which is uncertain. Moreover, cost overruns for deployment of grid modernization have been a problem in these pilots.

Requiring the EDCs to rely on traditional base rate cases for cost recovery will encourage the EDCs to invest prudently in technologies that will achieve the Department's goals at least cost and deliver the claimed benefits while minimizing the risk of obsolescence. The Enhanced Regulatory Model lowers the risks that would be imposed on ratepayers as compared with the recommendations for regulatory reform suggested by other stakeholders.

Therefore, the Department should limit its current action to adopting the regulatory enhancements provided in the Enhanced Regulatory Model. The modifications are modest, and the justification for adding a pre-approval proceeding for customer facing programs is clear. Customer-facing investments, such as advanced metering, typically involve a large investment that may bring demonstrated risks as noted above. The additional pre-approval proceeding is necessary to minimize those risks. Under the Enhanced Regulatory Model, the EDCs should continue to move forward by making individual, targeted proposals.

Finally, there are many topic-specific issues that will need to be addressed in the future. To answer key questions regarding time varying rates, the Department should open a generic investigation to evaluate the EDCs' role in providing time varying rate service as proposed by the Office of the Attorney General and the Low Income Network in Chapter 8 of the Final Report. The Attorney General's Office and the Low Income Network provided recommendations in Chapter 5 of the Final Report that are necessary to protect customer interests, including consumer protection, privacy, cyber security, and the promotion of TVR options through retail supplier offerings.

III. COMMENT

A. The Department's Grid Modernization Policy Should Promote Affordability

First and foremost, the Department should tailor its policies on grid modernization to meet the reality of energy costs in Massachusetts. Massachusetts' residential, commercial, and industrial electric customers pay some of the highest electricity rates in the country. The Commonwealth is likely to remain near the top of that list in the near future. Certainly, it is difficult to predict rates. However, future drivers

¹⁰ See *id.*, pp. 32-36 (discussing the Massachusetts pilot programs).

of electric rates will likely include transmission costs, the replacement of old and inefficient infrastructure, the cost of government energy-related mandates, and possibly wholesale electricity costs.¹¹ To help minimize impacts of future rate increases, the Department should adopt grid modernization policies that promote affordable rates for all.

Steering Committee Members all agree that “affordability must be addressed.”¹² Also, nearly all parties -- including all EDCs, ISO New England, consumer, environmental, and clean energy interests -- have recommended protections and affordability for low-income income customers.¹³ However, parties do not necessarily agree on how to achieve these goals. The Attorney General’s Office and the Low Income Network made recommendations set forth in the Final Report with a special emphasis on affordability, which the Department should adopt.

B. The Department’s Grid Modernization Policy Should Include Consumer-Related Protections and Policies

In addition to promoting the affordability of electric service, the principles and recommendations endorsed by the Attorney General’s Office and the Low Income Network in Chapter 5 of the Final Report seek to establish consumer-related protections and policies that the Department should now adopt.¹⁴ First, the Department should continue to require the EDCs to provide Basic Service as a flat rate service for residential customers.¹⁵ Second, the Department should ensure that any new time-varying rates and direct load control programs are provided on an optional basis.¹⁶ No state that has implemented retail electric competition has moved to adopt a default service rate structure that reflects TVR for residential customers, and all states have retained a flat rate service for residential customers that is based on a managed portfolio of wholesale market contracts.¹⁷ Further, the Department should adopt the important consumer protections associated with the functionalities of advanced metering, particularly with respect to

¹¹ For instance, federally regulated transmission rates will likely increase by 35 percent as a result of an additional \$3.8 billion in investments in the New England Region over the next four years through 2017. See A4 RNS Rates 5-year Forecast Presentation, ISO New England, slides 6 and 7 (July 22-23, 2013) (the \$86.95 projected 2013 rate per kW-Year is projected to increase to \$117.44 per kW-Year in 2017, and slide 6, where the incremental investments for 2014 through 2017 are \$907 million, \$1,122 million, \$892 million and \$893 million respectively available at http://www.iso-ne.com/committees/comm_wkgrps/reblty_comm/reblty/mtrls/2013/jul22232013/index.htm. Although generation supply costs have declined in recent years due to falling gas prices, it is unclear whether gas prices will remain at present levels in the future.

¹² *Final Report*, p. 9.

¹³ *Id.*, pp. 107, 119, 122, 125 n. 79.

¹⁴ See *Final Report*, pp. 51-56 (referring to principles endorsed by the Attorney General and Low Income Network in Sections 5.8 and 5.9).

¹⁵ *Id.*, p. 55 (Opt in vs. Opt Out vs. Mandatory Time Varying Rates, Principle No. 2); see also *Id.*, p. 54 (Coverage: Customer Classes, Principle No. 2).

¹⁶ *Id.*, p. 55 (Opt in vs. Opt Out vs. Mandatory Time Varying Rates, Principle No. 2).

¹⁷ *Id.*, p. 37, Table 4-10: TVR and Metering in Other Restructured States (showing restructured states that have a basic service design that is a flat rate for residential customers).

the switch that allows remote connection and disconnection of the meter without a premise visit.¹⁸ Finally, the Department should reinforce and enhance its existing consumer protection policies.¹⁹

The Department should adopt the consumer-related protection and policy recommendations endorsed by the Attorney General’s Office and the Low Income Network in Chapter 5 of the Final Report.

C. The Department Should Not Adopt a Grid Modernization Policy That Abandons the Traditional Approach to Cost Recovery and Cost-Effectiveness

The stakeholder input included in the Final Report provides the Department with a launching pad. However, nothing presented in the Final Report provides the basis for the Department to conclude that it should now significantly depart from the regulatory policies on cost recovery and cost-effectiveness in place today.

This is not to say that the Department should abstain from adopting a policy that enhances the existing regulatory framework in order to facilitate the grid modernization process and to provide additional oversight over the process. In fact, the Enhanced Regulatory Model does just that. The approach seeks to balance the desire to move forward with modernizing the distribution system and customer offerings in a manner that brings benefits to customers without burdening customers with unnecessary costs and risks. The Enhanced Regulatory Model appropriately balances risk between customers and EDCs.

1. The Final Report Does Not Provide a Reasonable Basis for the Department to Conclude That the Department Should Significantly Depart from Existing Cost Recovery and Cost-Effectiveness Policies

While the Department may change its regulatory policies under its existing statutory authority, its *October 2 Order* does not cite any specific evidence indicating why such a change is necessary in order to facilitate the grid modernization process.²⁰ The information in the Final Report is valuable, but it does not constitute specific evidence on which the Department should act.

For instance, the Final Report includes valuable information about the potential functionalities and attributes for selected grid-facing and customer-facing technologies, preliminary industry-wide cost

¹⁸ *Id.*, p. 52 (Remote Disconnect/Connect, Principles No. 2, 3 and 5); *c.f. Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid*, D.P.U. 11-129, pp. 63-64 (2012) (directing the utility to configure the meters so that the remote disconnect feature is disabled, but declining to require a the utility to “permanently or physically remove the remote shutoff features of its AMI meters” after finding that action was not possible).

¹⁹ *Final Report*, p. 51 (Consumer Protections, Principles No. 3 and 4).

²⁰ The Department has broad discretion to depart from established policy after a specific finding that such changes are within the public interest. *Deacon Transportation, Inc. v. Department of Public Utilities*, 388 Mass. 390, 395-396 (1983); *New England Telephone & Telegraph Company v. Department of Public Utilities*, 372, Mass. 678, 680 (1977). “[T]he requirement of “reasoned consistency” in *Boston Gas Company v. Department of Public Utilities*, 36 Mass. 92 (1975), means any change from an established pattern of conduct must be explained.” *Robinson v. Department of Public Utilities*, 416 Mass. 668, 673 (1993). “It does not mean that the DPU may never deviate from its original position.” *Id.*

information for metering infrastructure (adjusted by the EDCs based on knowledge and experience), and various reports about the metering infrastructure deployments and grid-facing deployments to date.²¹ However, this information is general, and it is not utility-specific. Without concrete utility-specific information about costs, benefits and the like, it is unclear why any change in the Department's cost recovery and cost-effectiveness policies is needed. Consider that the Final Report does not, on a utility-specific basis, identify the technologies that each EDC should deploy, quantify the costs and benefits associated with such deployment, develop customer bill impacts, or identify the timeframe during which such deployments might be reasonable.²² In fact, the Final Report does not, nor was it intended to, specifically identify for each EDC which technologies should be deployed. Furthermore, no party has specifically described what additional investments are needed, or why they cannot be implemented under the current regulatory system. These gaps in information should be filled before the Department embarks on any significant policy change.

The New York Public Service Commission ("New York PSC") recognizes the nebulous nature of grid modernization, noting that "the problem isn't just that 'smart grid' is a vague and over-applied term; the bigger problem is that it has morphed into a catch-all idea, stuffed full of promises that could smother the true potential."²³ The Final Report sought to address the nebulous nature of the term "grid modernization" by establishing grid modernization taxonomy and discussing "a range of metering technology options."²⁴

However, much of the information needed to help identify which technologies and programs are promising is not yet available. The federal government has invested billions of dollars in smart grid pilot projects nationwide, and most of those pilots are still in progress. In addition, two of the three Massachusetts EDCs have not yet concluded their Massachusetts smart grid pilot programs, and the Department has not fully evaluated the third EDC's program.²⁵ The results from these programs will be relevant in determining what significant deployments are promising, particularly for advanced metering investments.

²¹ *Final Report*, pp. 37-43

²² The relevant questions are captured on page 2 and 3 of this comment.

²³ *Proceeding on Motion of the Commission to Consider Regulatory Policies Regarding Smart Grid Systems and the Modernization of the Electric Grid*, Smart Grid Policy Statement, (Case 10-E-0285, August 19, 2011) ("NY Smart Grid Policy Statement"), p. 8 *citing* Steven Andersen, *Saving the Smart Grid*, PUBLIC UTILITIES FORTNIGHTLY, January 2011, Volume 149, No. 11, p. 33.

²⁴ *Final Report*, pp. 11, 40-43. However, Chapter 3 includes this caution: "[t]he use of each potential capability and enable 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." *Id.*

²⁵ *Id.*, pp. 32-36.

Therefore, the Department should not significantly amend its ratemaking policies in the absence of specific evidence of what is needed to encourage grid modernization, and why the existing regulatory system will inhibit the grid modernization process.

2. *The Department Should Adopt the Enhanced Regulatory Model*

The Department should adopt the Enhanced Regulatory Model to reasonably enhance its existing rate policies. The Enhanced Regulatory Model, which is fully described in the Final Report, features three key characteristics. The key characteristics include: (1) preserving the existing base rate case model; (2) retaining a least-cost approach to grid modernization, and; (3) enhancing the existing regulatory framework.

First, the proposal preserves the existing base rate model to facilitate deployment of grid modernization initiatives by the EDCs. In a base rate proceeding, the EDC has the burden to demonstrate that it prudently incurred distribution system upgrades and investments that fall under the grid modernization rubric, and that it followed used and useful, least-cost, cost allocation and cost assignment principles in place today.²⁶ A primary goal, to establish affordable and just and reasonable rates that minimize bill impacts to customers, would be preserved. The Department would evaluate cost-effectiveness of grid-facing investments through traditional means, preserving EDC discretion in making decisions about needed upgrades. Further, EDCs would use their own internal economic analyses to make appropriate decisions. Other states have recognized the value of the base rate approach and its applicability for recovery of grid modernization-related costs.²⁷

Second, the model promotes least-cost deployments by requiring the EDCs to operate under the base rate case model, as well as conduct a rigorous cost-effectiveness analysis.²⁸ This should include consideration of alternatives to the deployment. For instance, a direct load control program may be less expensive and may achieve similar goals to a TVR program that would require significant advanced meter rollout.

Third, the Enhanced Regulatory Model enhances the existing regulatory framework through: strengthening the reliability targets under the Department's Service Quality Guidelines; adding reporting requirements for grid-facing investments; establishing pre-approval processes for advanced meters, direct

²⁶ National Grid may recover costs associated with capital investments annually through its tracker. *Supra* note 10.

²⁷ See e.g. *Baltimore Gas and Electric Company* ("Baltimore Gas"), Order No. 83531 (Case No. 9208, August 13, 2010), p. 35 (disallowing a proposal to recover the costs for advanced meters through a rate tracker, but creating a means to capture carrying costs in the period that precedes a base rate case proceeding where rate base treatment would be determined); NY Smart Grid Policy Statement, p. 4 (stating that, in the near term, investments that provide a relatively certain return on investment should be recovered through a rate case proceeding, and recognizing that "[i]f a utility maintains that a novel or unproven technology will produce net benefits, [the commission] will consider risk sharing mechanisms in order to balance ratepayer and shareholder risks).

²⁸ *Final Report*, pp. 75-79 (describing the recommended cost-effectiveness).

load control and TVR programs; and formalizing a cost-effectiveness framework for advanced meters, direct load control and TVR programs.²⁹ With respect to increased reliability targets and reporting requirements for grid-facing investments, the model provides that 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 EDCs should continue to evaluate cost-effectiveness by using their own internal economic analyses to make the appropriate decisions. Costs should be recovered through base rates under the same regulatory scheme that the Department has successfully employed for many decades. This way, the EDC 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.

The Enhanced Regulatory Model also contemplates that the EDCs will file annual grid modernization status reports and plans. 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. The Department, as always, would have the opportunity to review actual grid-facing expenditures in the base rate case to determine whether they were least-cost, prudent, and reasonable, and whether the resulting rates, subject to cost allocation, are just and reasonable.

With respect to the addition of pre-approval processes for advanced meters, direct load control and TVR programs, this provides the Department, customers, and other stakeholders with an opportunity to review these programs before the EDCs spend any money on the programs. From the EDC standpoint, this should be attractive, because it is an opportunity to gain additional certainty around the recovery of costs associated with such investments and programs, assuming that the approved program can be delivered on time, meet its estimated cost projections, and achieve the estimated benefits or results. It is particularly attractive for customers, because it provides an opportunity to help ensure that the programs are cost effective and least-cost prior to any investment.

In addition, the Enhanced Regulatory Model employs a narrowly tailored cost effectiveness approach to evaluate advanced meters and direct load control investments based on Department precedent.³⁰ Under the proposal, an EDC would have the burden to demonstrate net benefits of a program in a pre-implementation proceeding.³¹ Net benefits are determined using a net present value revenue requirement method that is based on Department precedent.³² That method compares the expected life-cycle revenue requirements resulting from the program being operational and completely in base rates

²⁹ *Id.*, p. 61-63

³⁰ *Final Report*, pp. 77-79.

³¹ *Id.*

³² *Id. relying on Western Massachusetts Electric Company*, D.P.U. 85-270, pp. 71-75 (1985).

versus the revenue requirements of alternative scenarios in which a program is not operational and is replaced with other programs or investments as needed.³³ The difference between the stream of benefits and costs, when appropriately discounted and summed over time, is the net present worth of the resource.³⁴ Table 7-2 in the Final Report provides a list of quantifiable costs and benefits that would be included in the analysis.³⁵

In contrast, the business case approach offered by the Clean Energy Caucus and the EDCs raises concerns. This approach would “capture both the quantifiable and unquantifiable characteristics of a proposed project or investment.”³⁶ This overly broad approach to evaluating investments is a potentially expensive and unworkable approach that could result in the burdening of customers with higher costs and rates without providing commensurate benefits.

For instance, under the Clean Energy Caucuses proposal, all potential costs and benefits of an investment would be evaluated on a projected basis, regardless of whether they are quantifiable or not, and this includes societal costs.³⁷ The investment would be pre-approved “when the benefits of such investments exceed the costs . . . ”.³⁸ However, the proposal does not explain how this determination can be made when all of its components do not have numerical values. By using this sort of analysis, which includes a broad range of benefits, many of which are not quantified, the EDCs will more likely be able to obtain pre-approval for their grid modernization investments. Moreover, consistent with longstanding Department precedent and the Supreme Judicial Court’s interpretation of the scope of the Department’s jurisdiction, societal benefits that do not affect the utilities’ cost of service to customers cannot legally be included in the evaluation.³⁹

In addition, several stakeholders recommend that any evaluation of costs and benefits include a “value of service” approach in determining reliability benefits.⁴⁰ We are not aware of any state that has adopted such an approach. Moreover, the “value of service” approach would require a significant change in the Department’s approach to determining reliability impacts through its Service Quality Guidelines. The approach would require reliance on surveys that ask hypothetical questions to customers on the value

³³ *Final Report*, p. 78.

³⁴ *Id.*, p. 78.

³⁵ *Id.*, p. 79.

³⁶ *Id.*, p. 81.

³⁷ *Id.*, pp. 82, 84.

³⁸ *Id.*

³⁹ See e.g. *Order on Energy Efficiency Guidelines*, 08-50-A, p. 1 (2009); see also *Massachusetts Electric Company v. Dep’t of Pub. Utils.*, 419Mass. 239, 245-246 (1994) (stating that the Department could not take into account costs associated with environmental damages that do not and cannot reasonably be anticipated to have an effect on a utilities costs and thereby on the rates paid by customers without express statutory authority). However, as indicated in Table 7-2 of the Final Report, the recommended cost-effectiveness test does include quantifiable “Avoided Environmental Compliance Costs.” If an EDC can demonstrate that an advanced metering technology or direct load control program that it seeks to deploy will reduce carbon emissions, and that those reductions will result in avoided environmental compliance, then the avoided costs may be included in the cost-effectiveness test so long as the EDC is able to reasonably quantify the avoided environmental compliance costs.

⁴⁰ *Final Report*, p. 86.

that they put on an outage. The validity of this methodology is questionable for a variety of reasons including the fact that customers' willingness to pay for reliability cannot be measured with precision, and because that value will change depending on the income level and service class of the customer.⁴¹

3. *The Department Should Heed the Cautionary Tales from Other Jurisdictions*

The Enhanced Regulatory Framework is a reasonable approach to cost recovery and cost-effectiveness, especially in light of the examples that involve significant cost overruns, or the lack of customer benefits. The Department should consider the following examples from other states and the example of Massachusetts' own Fitchburg Gas and Electric Light Company d/b/a Unitil ("Fitchburg"), which illustrate substantial cost risks associated with "grid modernization."

Consider the Maine Public Utility Commission's ("Maine PUC") recent conundrum that arose after issuing a decision on January 19, 2010, authorizing an aggressive deployment of advanced metering based on estimates that the program would provide \$25 million in net benefits from operational savings over 20 years plus supply side savings.⁴² Just over two years later, the Maine PUC opened a proceeding to initiate a management audit of the utility's AMI project stating, "[w]hile this calculation is only a preliminary estimate, this apparent shift from a net ratepayer benefit [\$25 million] at the time AMI was authorized to a substantial net increase in costs to [\$99 million] now that the project has been completed and CMP is seeking to reflect AMI costs in rates, is of great concern to the Commission."⁴³ The Maine PUC also noted that, "[i]n addition to the mis-estimates (sic) and degradation of net savings on the T&D side, we are also concerned about the lack of capability to deliver customer benefits on the electric side."⁴⁴ The Maine PUC expects to use the audit in determining cost recovery.⁴⁵

Similarly, the 2008 Smart Grid demonstration project by the Public Service Company of Colorado, which sought to "integrate and deploy emerging 'smart grid' technologies in a comprehensive and interdependent manner in the City of Boulder, Colorado ("Boulder") as a first of its kind demonstration project," and included deployment of both grid-facing and customer facing technologies saw costs balloon.⁴⁶ Over a series of base rate case filings the Colorado Public Utility Commission

⁴¹ See e.g. Freeman, Sullivan & Co., *How to Assess the Economic Consequences of Smart Grid Reliability Investments*, (November 29, 2010), pp. 6-7 available at: <http://fscgroup.com/reports/how-to-assess-the-economic-consequences-of-reliability-investments.pdf>. This recent report funded by the National Association of Regulatory Utility Commissioners (NARUC) for the Illinois Commerce Commission discussed the difficulty with measuring impacts of Smart Grid investments on customer reliability of service. See also Freeman, et al., *Estimating Value of Service Reliability for Electric Utility Customers in the U.S.*, Lawrence Berkeley National Laboratory, LBNL-2132E (June 2009) (noting the distinct difference in valuing an outage for lower income customers compared to other customers).

⁴² *Central Maine Power Company*, Docket No. 2010-00051, p. 3, (June 2013) (initiating a management audit).

⁴³ *Id.*, p. 4.

⁴⁴ *Id.*

⁴⁵ *Id.*, p. 5.

⁴⁶ *Application of Public Service Company of Colorado for Approval of the Smart Grid City Cost Recovery*, Decision No. C13-0436, Docket No. 11A-1001E, p. 2 (March 21, 2013).

("PUC") saw the utility's estimates increase from the original estimate of \$16 million in its 2008 rate case, to \$27.9 million in the Company's rate case in 2009, and those costs were adjusted later upward to \$42 million and then \$44.5 million.⁴⁷ Ultimately, the Colorado PUC found that the utility failed to demonstrate the prudence of the \$16.6 million cost overrun of the investment (\$44.5 - \$27.9 million), which was disallowed.⁴⁸

Other states have experienced significant cost overruns with advanced metering deployment. The premature adoption of the new metering and communication technologies have resulted in stranded costs and significant increases in the budgets for these new systems in California. The California PUC approved PG&E's request to increase costs by almost \$1 billion to change the communication system that was included in the original smart metering deployment application.⁴⁹ The same experience has occurred in Texas where Oncor Electric Delivery Co. installed smart meters that were later found not to comply with the resulting Texas PUC standards for these new metering systems. Nonetheless, Oncor's electricity customers were required to pay \$93 million for the obsolete smart meters that were never installed and \$686 million for meters with the newer technology.⁵⁰

Massachusetts has had its own experience with cost overruns associated with grid modernization investments. In its D.P.U. 09-31 Order, the Department approved a budget for the Unitil's smart grid program of \$114,029.⁵¹ The Company's program pilot costs have reached \$239,737.⁵²

D. Proposals to Make Significant Amendments to the Department's Rate Recovery and Cost Effectiveness Methods for Evaluating Capital Investments Should Not Be Adopted at this Time

Grid modernization appears to be yet another way for the EDCs to endorse cost recovery mechanisms that will benefit their shareholders. The Department should view with skepticism any "grid

⁴⁷ *Id.*, pp. 2-3.

⁴⁸ *Id.*, pp. 12-13.

⁴⁹ In fact, the actual experience associated with the implementation of smart metering and the associated communication systems in California reflect higher costs and delayed installation. For example, Pacific Gas & Electric halted its AMI deployment in order to make a change in its communication system and metering functionality. The utility subsequently sought and obtained approval from the California PUC to increase its AMI costs by over \$900 million on a present value basis, thus bringing the total cost estimate to roughly \$3.2 billion. Cal. PUC Docket No. A.07-12-009. See California PUC News Release issued March 12, 2009, available at: http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/98459.htm

⁵⁰ According to an August 3, 2009 article in the *Dallas Morning News*, "Consumers are already paying \$2.21 a month for the new round of meters, as retail electricity companies pass along Oncor's charge to their customers. That cost will last 11 years. If commissioners decide consumers must pay for the first smart meters, that could add about \$1.70 a month to the average customer's bill, according to calculations by the Steering Committee of Oncor Cities." Elizabeth Souder, *Consumers may pay for meters: \$93 million query Did Oncor or PUC make a mistake?*, *Dallas Morn. News*, Aug. 3, 2009 (available on Westlaw - 2009 WLNR 14980260). The Texas PUC issued an order allowing cost recovery for the obsolete meters. See *Application of Oncor Electric Delivery Co. LLC for Authority to Change Rates*, PUC Docket No. 35717, pp. 6-7 (August 31, 2009).

⁵¹ *Fitchburg Gas and Electric Light Company d/b/a Unitil*, D.P.U. 09-31, pp. 26-27 (2010).

⁵² *Initial Brief of the Fitchburg Gas and Electric Light Company, d/b/a/ Unitil*, D.P.U. 11-82/97, p. 2 (June 19, 2012) (final order pending).

modernization” cost recovery proposal that would grant the EDCs the ability to shift costs to ratepayers prior to the documentation of prudent costs and actual benefits.

First, the EDCs have not yet provided sufficient evidence to support a conclusion that consideration of a special rate treatment for “grid modernization” costs is appropriate. While the EDCs’ shareholders stand to benefit from additional cost certainty for capital investments that would normally be recovered through a base rate case proceeding, no commensurate ratepayer benefits have been demonstrated.

The Department does not and should not readily hand out special rate treatment to the EDCs upon request. It has approved such rate treatment for targeted capital investments only in limited cases.⁵³ Thus, the Department should consider the uncertainties around costs and benefits associated with grid modernization technologies and practices. As the Maryland PUC put it, “with a tracker, it would be nearly impossible to unring the bell.”⁵⁴ The Commission further stated that “[m]oney would flow from customers to the Company before significant benefits, and Baltimore Gas and Electric’s (“BGE”) well-intentioned review proposal would put us to the impracticable, challenge . . . of monitoring this project in real time and making on-the-fly decisions . . . about how and on what terms to proceed.”⁵⁵

The Department has frequently declined to adopt a future test year approach to ratemaking for good reasons, among them administrative inefficiencies, inability to adequately forecast a test year, and due process concerns.⁵⁶ It has stated that to “allow for the recovery in rates of capital projects that have not yet been reviewed and deemed prudent and used and useful by the Department would be akin to institution of a future test year, an idea rejected by the Department in its Decoupling Order as inconsistent with long-standing Department precedent.”⁵⁷

⁵³ It is not appropriate to recover costs through trackers unless they are: (1) objectively ascertainable; (2) over which a company has very little control; and (3) that may materially affect a company's operations; *Consumers Organization for Fair Energy Equality v. DPU*, 368 Mass. 599, 601-608 (1975).

⁵⁴ *Baltimore Gas and Electric*, p. 40.

⁵⁵ *Id.*

⁵⁶ See e.g. *Massachusetts Electric Company and Nantucket Electric Company*, D.P.U. 09-39, p. 84; *Decoupling Order*, D.P.U. 07-50-A, pp. 51-53 (2008); see also D.P.U. 12-25, p. 18 citing D.P.U. 1580, p. 19 (noting that a future test year “could have detrimental effects on the rights of due process of parties to [our] proceedings.”) The Department has “previously stated that we [view] the adoption of the future test year as fraught with speculation and uncertainty . . . [and there] are too many variables which affect the cost of service to justify employing a future test period.” *Bay State Gas Company*, D.P.U. 12-25, p. 18 (2012) citing *New England Telephone & Telegraph Company*, D.P.U. 18210, pp. 2-3 (1975).

⁵⁷ *Massachusetts Electric Company, Nantucket Electric Company, d/b/a/ National Grid*, D.P.U. 09-39, p. 84 (2009) relying on D.P.U. 07-50, p. 51-53.

E. The Department Should Not Make Sweeping Changes to Its Regulatory Policy on Cost Recovery and Cost-Effectiveness in a Generic Docket

A number of signatories to the Final Report have requested that the Department open a generic proceeding that is similar to the decoupling proceeding, D.P.U. 07-50.⁵⁸ As noted above, the Department should adopt the Enhanced Regulatory Proposal, and subsequently review the EDCs' grid modernization plans and investments in the manner prescribed therein. As such, each EDC would make a case for grid modernization technologies within the context of a base rate case. In the case of TVR, direct load and advanced metering programs, the EDCs would make a case for their proposal in a pre-approval proceeding.

The grid modernization process is not like the process to ramp up energy efficiency. In D.P.U. 07-50, the question was whether the Department should amend its regulatory structure to remove disincentives to the EDCs' deployment of energy efficiency.⁵⁹ Energy efficiency technologies had been around for at least two decades and had proven results of delivering benefits associated with the reduction of energy usage. To the contrary, deployment of grid modernization investments like advanced metering investments poses a significant risk to customers, and has often been associated with cost overruns as well as indirect and highly uncertain future benefits.⁶⁰ Under these circumstances, the only appropriate course of action is for the Department to conduct fact-dependent evaluations of individual EDC proposals to deploy grid modernization technologies and programs. The Department should not make such decisions at the theoretical level.

The Department should require each EDC (and other stakeholders) to provide testimony and supporting evidence to justify recommendations for any significant change to the Department's regulatory policy on cost-effectiveness and cost recovery. In particular, the Department should require the EDCs to substantiate claims that they need "special" rate recovery treatment to facilitate grid modernization and to provide an outline to the Department of what their plans are for grid modernization and the customer costs and benefits of those plans. In any case, it is well settled that the Department cannot approve rate increases to pay for investments in grid modernization outside of a base rate case proceeding.⁶¹

⁵⁸ Final Report, p. 93 (NSTAR Electric Company, Western Massachusetts Electric Company, Fitchburg Gas and Electric Light Company, d/b/a/ Unutil, Cape Light Compact, and General Electric recommended that the Department open up a generic docket of this scope and nature.).

⁵⁹ See *Vote and Order Opening an Investigation into Decoupling Order*, D.P.U. 07-50 (June 22, 2007).

⁶⁰ See *supra* Section III, D(2).

⁶¹ 368 Mass. 599, 601-608; D.P.U. 07-50-A, p. 84.

IV. CONCLUSION

Accordingly, for the reasons described herein, the Attorney General's Office, the Low Income Network, and the Associated Industries of Massachusetts respectfully request that the Department adopt the following recommendations:

- Affirm the principles of prudence, used and useful, least cost, appropriate allocation among rate classes, affordability, and consideration of rate and bill impacts;
- Adopt the Enhanced Regulatory Model and the associated Cost-Effectiveness Framework, and implement the model as outlined in Chapter 8 of the Final Report;
- Conduct the investigation into TVR as outlined in Chapter 8 of the Final Report;
- Adopt the principles endorsed by the Attorney General's Office and the Low Income Network in Chapter 5 of the Final Report;
- Conduct fact-specific adjudications to investigate proposals that the EDCs may file under the Enhanced Regulatory Model;
- Require each EDC (and other stakeholders) to provide testimony and supporting evidence to justify recommendations for any significant change to the Department's regulatory policy, and;
- Adopt any other measures that the Department deems appropriate.

Respectfully, the following parties submit this Joint Initial Comment:

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