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September 23, 2015

Ms. Luly Massaro, Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: Docket 4568

Dear Ms. Massaro:

Enclosed please find an original and nine copies of the following document:

1. Direct Testimony of Janet Gail Besser, Vice President, Policy and Government Affairs, Northeast Clean Energy Council.

Please note that an electronic copy of this document has been provided to the service list.

Thank you for your attention to this matter.

Sincerely,

Joseph A. Keough, Jr.

JAK/kf
Enclosures
cc: Docket 4568 Service List *(via electronic mail)*

STATE OFRHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: REVIEW OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID'S RATE DESIGN PURSUANT TO R.I. GEN. LAWS § 39-26.6-4

Docket NO. 4568

PREFILED DIRECT TESTIMONY

OF

JANET GAIL BESSER
VICE PRESIDENT, POLICY AND GOVERNMENT AFFAIRS,
NORTHEAST CLEAN ENERGY COUNCIL

October 23, 2015

Introduction And Qualifications of Janet Gail Besser

Q. Please state your name and business address?

A. My name is Janet Gail Besser and my business address is 250 Summer Street, 5th Floor, Boston, Massachusetts 02210.

Q. By whom are you employed and in what capacity?

A. I am Vice President, Policy and Government Affairs for NECEC, the Northeast Clean Energy Council, a clean energy business, policy and innovation organization whose mission is to create a world-class clean energy hub in the Northeast delivering global impact with economic, energy and environmental solutions. NECEC represents the clean energy industry broadly, advocating for policies that advance clean energy across the range of technologies from solar to energy efficiency, demand response, grid-scale renewable energy, clean and renewable distributed generation, combined heat and power, energy storage, biofuels, fuel cells and advanced and "smart" technologies. Our member companies are diverse, ranging from small start-ups to large international corporations and include all sizes of companies providing services to a variety of customers under a variety of business models. Many of our members are located or do business in Rhode Island.

Q. Please describe your educational background.

A. I hold a Bachelor of Arts degree, *magna cum laude*, in Political Science from Williams College and a Master of Public Policy degree from the Kennedy School of Government at Harvard University.

Q. Please describe your professional experience.

A. I have worked in the energy industry in a variety of roles since 1980. Currently, I lead NECEC's policy development and advocacy efforts. Prior to joining NECEC in January 2012, I was Vice President, Regulatory Strategy, for National Grid USA, from 2007 to 2011, where I was responsible for development, coordination and articulation of regulatory strategy across National Grid's distribution, transmission and gas lines of business and Vice President, Transmission Regulation and Commercial Services, from 2004 to 2007, where I oversaw all regulatory and commercial policy issues for US Transmission at the federal and state levels. Prior to that I held positions as Vice President at Analysis Group, Inc. (2003-2004) and Senior Vice President at Lexecon Inc. (2000-2003), two economic, regulatory, policy and strategy consulting firms, providing expert advice to a variety of clients.

Prior to becoming a consultant, I was the Chair and Commissioner of the Massachusetts Department of Telecommunications and Energy (now Department of Public Utilities) from 1995 to 2000, where I oversaw Massachusetts' nation-leading electricity industry restructuring initiatives. As a commissioner, I served as a member of the Board of Directors of the National Association of Regulatory Utility Commissioners and as member and Vice-Chair of its Energy Resources and Environment Committee. I was also a member and past President of the New England Conference of Public Utilities Commissioners, and a member of the Electric Power Research Institute's Advisory Council, the Energy Foundation's Utility Futures Group, and the Harvard Electricity Policy Group.

I also served as the Policy Director of the National Independent Energy Producers (NIEP), a Washington, DC-based trade association, and held senior staff positions at the Massachusetts and New Hampshire public utility commissions and the Massachusetts Executive Office of Energy Resources. I was Assistant to the Director of Development at Essex Hydro Associates and began my energy career with the Low-Income Energy Advocate's office with the Community Action Programs of Belknap-Merrimack Counties, Inc., in New Hampshire. My resume and CV are attached to my testimony as Appendix A.

Q. Have you ever testified before a state or federal regulatory commission?

A. Yes. I have testified for the Massachusetts Executive Office of Energy Affairs before the Massachusetts Department of Public Utilities (1988), for the staff before the New Hampshire Public Utilities Commission (1989, 1991), for the New Hampshire Public Utilities Commission before the Federal Regulatory Commission (1989), for National Grid before the Massachusetts Department of Public Utilities (2007), and for NECEC before the Massachusetts Department of Public Utilities (2014). As a consultant, I also testified before the Public Service Commission of the State of Mississippi on behalf of Colonial Pipeline Company and before the Arkansas Public Service Commission on behalf of the Arkansas Electric Distribution Cooperatives. Additional details can be found in my resume and CV in Appendix A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the rate design proposal submitted by the Narragansett Electric Company, d/b/a National Grid ("National Grid" or the "Company") in this proceeding, specifically its proposal to implement a four-tiered customer charge for Residential Rate A-16 ("Rate A-16"), and Small Commercial and Industrial ("C&I") Rate C-06 ("Rate C-06"). Pursuant to the revised procedural schedule issued on October 16, 2015, I will file testimony addressing the Company's proposal for an Access Fee for stand-alone distributed generation facilities on November 23, 2015, if necessary.

Q. On whose behalf are you submitting testimony in this proceeding?

A. I am submitting testimony on behalf of NECEC.

Q. How is your testimony organized?

A. Section I of my testimony addresses the purpose of the proceeding as described in the Renewable Energy Growth Program Statute ("REG Statute") (RIGL §39-26.6). Section II addresses the problems with the Company's proposal for a tiered customer charge for Rate A-16 and C-06. Section III discusses actions or steps that need to be taken to arrive at an appropriate rate design proposal. Finally, Section IV presents my recommendation to the Commission in this proceeding.

I. Requirements of the Renewable Energy Growth Program Statute

Q. Please describe the requirements of the REG statute as they relate to this proceeding.

A. The REG Statute requires the Commission to "open a docket to consider rate design and distribution cost allocation among rate classes in light of net metering and the changing distribution system that is expect to include more distributed energy resources, including, but not limited to, distributed generation." (RIGL §39-29.6-24) The REG Statute goes on to say that "the commission shall take into account and balance" a number of factors, including "the benefits of distributed energy resources" and "[t]he general assembly's legislative purposes in creating the distributed generation growth program." (RIGL §39-29.6-24) This purpose is "to facilitate and promote installation of grid-connected generation of renewable energy; support and encourage development of distributed renewable energy generation systems; reduce environmental impacts; reduce carbon emissions that contribute to climate change by encouraging the siting of renewable energy projects in the load zone of the electric distribution company; diversify the energy generation sources within the load zone of the electric distribution company; stimulate economic development; improve distribution system resilience and reliability within the load zone of the electric distribution company; and reduce distribution system costs." (RIGL §39-26.6-1)

Q. Does National Grid's filing address the factors enumerated in the REG Statute?

A. No, it does not. The REG Statute makes it clear that the Commission it to consider factors beyond the benefits and costs of distributed energy resources (DER) to the distribution grid *per se*. In its filing, National Grid's appears to be focused only on the benefits and costs to the distribution grid and not more broadly. In my testimony I will note where broader consideration of benefits and costs is needed to fulfill the direction of the REG Statute.

II. National Grid's Rate Design Proposal for a Tiered Customer Charge

Q. Do you agree that National Grid's proposal for a tiered customer charge should be approved?

A. No. I do not.

Q. Please elaborate.

A. National Grid's rate design proposal is not appropriate for the following six reasons:

1. National Grid's assertion that distribution rates based on demand charges would be the "ideal" (National Grid Joint Pre-Filed Direct Testimony, Bates 20) rate design for the future is not universally supported.
2. Even if distribution rates based on demand charges were appropriate, National Grid's proposal to use a tiered customer charge structure is not a good approximation of a demand charge structure.
3. The complexity of a distribution rate design based on tiered customer charges will require significant customer outreach and education, for which National Grid has not presented a plan or cost estimates.
4. The complexity and cost of implementing a distribution rate design based on tiered customer charges is not warranted by the extent of net metering and the size of the REG program at this time.
5. The Company's proposal for a tiered customer charge is not consistent with the objective of the REG statute.
6. Finally, National Grid's rate design proposal does not represent a step toward a long-term solution to addressing the changing nature of the electricity system in Rhode Island.

I will address each of these issues in more detail herein below.

Q. Can you address the first issue that National Grid's assertion that distribution rates based on demand charges would be the "optimal" rate design for the future is not universally supported.

A. Demand charges as they are generally applied are less than optimal because they do not do a good job of accomplishing one of the two purposes of rate design – providing an accurate price signal to customers about the costs incurred by the distribution utility to serve them. The other primary purpose of rate design is providing the distribution utility with the opportunity to recover the costs incurred to serve customers. Another important criterion that is one of the factors to be considered in this proceeding is "the allocation of the costs of the distribution system among customers." (RIGL § 39-29.6-24) It is not clear that demand charges as they are generally implemented do a good job with respect to this criterion either.

Q. Please elaborate.

A. A recent paper by Jim Lazar and Wilson Gonzalez for the Regulatory Assistance Project, entitled "*Smart Rate Design for a Smart Future*"[1] discuses the shortcomings of demand charges in rate design. The paper notes, "[D]emand charges have typically been applied to the individual peak demand of each consumer, regardless of whether it occurs during system peak periods." (*Smart Rate Design for a Smart Future*, page 37) This individual peak is generally referred to as the "non-coincident peak" or "NCP." The NCP is the peak demand that National Grid is proposing to approximate with its tiered customer charge rate design proposal. *Smart Rate Design for a Smart Future* and others explain that demand charges are used to send a signal to customers about their usage at system peak, when costs are high, referred to as "Coincident Peak" or "CP." National Grid notes repeatedly that it wants to encourage

[1] Lazar, J. and Gonzalez, W. (2015). Smart Rate Design for a Smart Future. Montpelier, VT: Regulatory Assistance Project. ("*Smart Rate Design for a Smart Future*") Available at: http://www.raponline.org/document/download/id/7680. Also included in testimony filed by the Energy Efficiency and Resource Management Council, Bates 33 – 130.

customers to reduce their peak usage. Sending customers a signal to reduce their individual peak usage or NCP will have a greatly attenuated effect on system peak usage making it not a good rate design to accomplish National Grid's goal.

In addition, basing rates on NCP demand may also fail to address the distribution cost allocation issue National Grid asserts. *Smart Rate Design for a Smart Future* states, "While the revenue to be collected is represented by the system coincident peak costs, the billing unit used to set the prices are the sum of all customers' individual non-coincident peaks." (*Smart Rate Design for a Smart Future*, page 37) While the National Grid proposal is focused on distribution circuit peaks, the *Smart Rate Design for a Smart Future* asserts that the effect should be similar. Another confounding factor is that the distributions system is built to a size that takes into account the "diversity of load" among all distribution customers. (National Grid Joint Pre-Filed Direct Testimony, Bates 31 – 33; 44) Yet the National Grid (ideal) proposal would charge customers based on their individual peak demands (or a proxy for them). Customers whose individual peak does not coincide with the distribution peak will pay more than their share and customers whose peak does coincide will pay less, which is also inconsistent with cost causation principles.

Smart Rate Design for a Smart Future goes further arguing that extending the application of demand charges from industrial customers to residential and small commercial as a way to ensure that solar customers contribute to distribution system costs is "inapt for most situations for several reasons, " including the diversity of load cited by National Grid. (Smart Rate Design for a Smart Future, page 51)

Q. Are there other problems with a distribution rate design based on demand charges?

A. The effectiveness of including a demand charge in rates as a signal to customers to change usage depends on their ability to see it, change their behavior and then see changes in the charges to them or costs they pay within a reasonable time frame. The National Grid proposal includes a 12-month ratchet, which requires a customer to pay based on his or her highest usage in a 12-month period on a rolling average basis. Ratchets are common with demand charges though the time periods may vary. This practice further undermines the price signal that customers see because they cannot realize the benefits of their behavior changes for an extended period of time. This can also aggravate the mismatch between on-peak costs and on-peak usage. (*Smart Rate Design for a Smart Future*, page 38)

Q. Do you have any other comments about demand charges?

A. Yes. Demand charges are actually volumetric based on the number of kW a customer uses. They are not fixed monthly, or as in National Grid's proposal, fixed yearly charges. Charging customers based on demand requires metering not in place. And National Grid has indicated that it does not have plans to put this metering in place. If National Grid believes that demand charges represent an ideal rate design, then the Company should present a benefit-cost analysis of the metering that would be needed to implement it. Among the benefits of the such advanced metering functionality is that it would provide information to customers that would enable them to see the price signal in a timely manner and thereby react to it. A demand charge that customers cannot see and cannot react to may help utilities with cost recovery but it will not help to reduce the overall costs of the distribution or enhance its efficient utilization, which National Grid appears to acknowledge. (National Grid Joint Pre-Filed Direct Testimony, Bates 37)

For the purposes of this proceeding, the costs of metering needed to implement demand charges should also be compared to the costs of implementing the tiered customer charge as an interim proposal. In addition to the other shortcomings of the tiered customer charge proposal, which I will discuss below, it may represent an expense for the Company, and ultimately customers, that is a diversion from the path to an ideal rate design.

Q. What would be a better rate design than demand charges?

A. *Smart Rate Design for a Smart Future* recommends implementation of Time Varying Rates ("TVR") over demand charges. (*Smart Rate Design for a Smart Future*, page 9) It notes that demand charges were implemented for commercial and industrial customers when more advanced metering was not available or too expensive. (*Smart Rate Design for a Smart Future*, page 51) It is worth further analysis of the benefits and costs of implementing TVR before concluding demand-based rates are an appropriate interim solution.

Q. What about metering needs for TVR?

A. Both TVR and demand-based rates require more advanced metering functionality. A next step for National Grid in Rhode Island should be conducting or presenting a benefit cost analysis of deployment of advanced metering and other functionalities that would enable more efficient use of the distribution grid. The Company can also take advantage of efforts underway in neighboring states addressing the issue of the technical capabilities needed to implement demand charges and TVR.

For example, in the New York Renewing the Energy Vision ("REV") proceeding, the "Staff White Paper on Ratemaking and Utility Business Models" ("Track 2 Staff White Paper") discusses the importance of moving to demand charges (and TVR) not as part of a "mere reallocation of costs among customers" but "as part of a broader strategy to reduce long-term system infrastructure needs, encourage the optimal development of DER, discourage uneconomic bypass of the distribution system, and maintain affordable rates for all customers," objectives similar to those articulated in the REG Statute. (Track 2 Staff White Paper, page 98)[2]

[2] Case 14-M-0101, "Staff White Paper on Ratemaking and Utility Business Models," New York Department of Public Service, July 28, 2015. For full discussion see pages 98 - 101.

Q. The second issue you raised is that National Grid's proposal to use a tiered customer charge structure is not a good approximation of a demand charge structure, even if distribution rates based on demand charges were appropriate. Can you explain why?

A. Yes. In Table 1, National Grid's own testimony shows a wide range of usage associated with the same level of demand. Each of these three illustrative customers has an annual maximum demand of 2 kW, which according to National Grid means their impact on the distribution grid is similar if not the same. However, their usage ranges from 3,000 kWh per year (250 kWh per month) for Customer 1, which would put him/her in Tier 1 paying a customer charge of $5.25/month; 5,000 kWh per year (417 kWh per month) for Customer 2, which would put him/her in Tier 2 paying a customer charge of $8.50 per month; and 10,000 kWh per year (833 kWh per month) for Customer 3, which would put him/her in Tier 3 paying $13.00 per month. (National Grid Joint Pre-Filed Direct Testimony, Bates 26) Under National Grid's proposals, these customers would pay different amounts for the same level of distribution service.

Q. Are there other reasons why the tiered customer charge is not a good proxy for a demand charge?

A. Yes. The Company's analysis of Residential load data for the relationship between Maximum Billed Usage and Maximum Hourly Load shows that usage explains only 46%, or less than half, of the variation in load (R-squared = .4648). (Schedule NG-7, Bates 131) While the correlation for Commercial customers is higher (R-squared = .7273), there is still considerable variability. (Schedule NG-7, Bates 132) I would also note that the residential load research sample on which this analysis is based includes only 200 customers.

Q. Is National Grid's tiered customer charge better in any way than a demand charge?

A. No. National Grid's tiered customer charge proxy for a demand charge is subject to a number of the same weaknesses as an actual demand charge. National Grid's witnesses discuss the fact that distribution planners take into account the "diversity of demand on the system and account for that in their system design." (National Grid Joint Pre-Filed Direct Testimony, Bates 31) As National Grid and *Smart Rate Design for a Smart Future* point out, all customers get the value of diversity through a lower revenue requirement or demand charge overall, but individual customers are billed at the tier in which their usage places them, or their NCP, meaning that customers whose usage/demand occurs off peak subsidize customers whose usage/demand is on peak. (Smart Rate Design for a Smart Future, page 37)

Similarly, in the Company's tiered customer charge proposal, the price signal to customers is muted because customers are billed for hitting a peak level of usage after the fact and then must pay a higher customer charge for another 12 months or until they hit an even higher level of usage. Practically speaking, this would require a customer to remember that he/she hit a peak level of usage, say in July of one year, which he/she would only find out in mid-August, so that he/she could change their behavior in the following July. To provide customers with an opportunity to see and react to the tiered customer charge rate design as proposed will require significant and ongoing outreach and communications throughout the year, the costs of which should be taken into account in evaluating this proposal.

Q. Anything else?

A. National Grid's proposal may actually send a mixed signal to DG customers to maximize production to reduce kWh so that they can fall into a lower customer charge tier. In National Grid's words, the incentive to "over-generate" under the current construct will increase. (N.Grid response to Division 1-17, Bates 25) In addition, the rate design proposal appears to run counter to the incentive National Grid is trying to send in its Tiverton pilot to have customers orient solar to maximize output at peak times and save costs for the distribution and larger electricity system rather than maximize kwh production.[3]

[3] Peregrine Energy Group Inc.'s June 2014 Report "Solar PV for Distribution Grid Support: The Rhode Island System Reliability Procurement Solar Distributed Generation Pilot Project" cited in N. Grid's response to NECEC 1-2, Bates 3-25.

Q. Please address the third issue that you raised – that the complexity of a distribution rate design based on tiered customer charges will require significant customer outreach and education, for which National Grid has not presented a plan or cost estimates.

A. The tiered customer charge rate design that National Grid proposes will be confusing to all customers, with and without DG, and will require significant customer outreach and education, equivalent to that required for advanced metering and TVR.

National Grid has not yet developed a customer outreach and education plan (N. Grid's response to PUC 1-20, Bates 45) nor indicated the estimated cost of such an effort. Implementation of a tiered customer charge will require up front outreach and education as customers will have questions about the change, and ongoing customer support to respond to customers' questions as they see changes in the customer charges on their bills.

Q. The fourth issue that you raised is that the complexity and cost of implementing a distribution rate design based on tiered customer charges is not warranted by the extent of net metering and the size of the REG program at this time. Would you please elaborate?

A. The size of the "problem" with distribution cost allocation resulting from the REG program and net metering in Rhode Island is small in terms of total revenues collected by the company. The total REG program size is 160 MW and 12 MW have been reserved for residential and small commercial and industrial customers. Net metering in Rhode Island is largely behind the meter and remote net metering is reserved to public entities, limiting its impact.

While National Grid notes that it cannot provide "an accurate calculation of annual lost [delivery] revenue from net metering," it estimates that it is approximately $760,932 for 2014. (N.Grid response to PUC 1-5, Bates 7) The estimated cost of the REG program due to "displaced kWh" is about $1.13 million. (N.Grid response to CLF 1-16, Bates 30) The total of about $2 million is approximately 0.8 % of the total revenue requirement of $251 million (Schedule NG-10, Bates 139), not a significant amount. The estimated displaced kWh for the four years of the REG program, over a 25 year period, are only $8.3 million (N.Grid response to CLF 1-16, Bates 30), or 3.3% of National Grid's current revenue requirement, (which is reasonably likely to increase over this period).

In addition, the implication that Rhode Island will see DER growth comparable to that experienced in Hawaii, California or Germany (National Grid Joint Pre-Filed Direct Testimony, Bates 16) over the next few years is not credible. Hawaii, California and Germany have significantly higher levels of support for renewable energy as well as higher costs for electricity.

Moreover, the distribution cost allocation issue is being addressed to some degree already in the provision in the REG Statute for recovery of program costs in "a fixed monthly charge per customer…charged to all distribution customers." (RIGL § 39-26.6-13 and §39-26.6-25)

Q. **While the distribution cost allocation issue may be small, shouldn't customers who use the distribution grid pay for that use?**

A. I agree that all users of the distribution grid should pay for that use, and I further agree that DG customers use the grid. (National Grid Joint Pre-Filed Direct Testimony, Bates 17-18) However, the cost and complexity of National Grid's proposed "solution" cannot be justified by the size of the "problem" now or in the next few years.

Q. Shouldn't National Grid be thinking about the future implications for distribution cost allocation of increasing amounts of DER?

A. I understand that National Grid is looking at an electricity system future with increasing amounts of DER, as is NECEC. We want to see the Company anticipating and planning to truly integrate more DER and laying the foundation for a better rate design proposal that will advance the Company and its customers into the future rather than implementing this inappropriate and less than "ideal," in National Grid's own words (National Grid Joint Pre-Filed Direct Testimony, Bates 20), rate design now.

Q. You also raised the issue that the Company's proposal for a tiered customer charge is not consistent with the objective of the REG Statute. Would you please explain why it is not consistent?

A. The first stated purpose of the REG Statute is "to facilitate and promote installation of grid-connected generation of renewable energy" and the second is to "support and encourage development of distributed renewable energy generation systems." (RIGL §39-26.6-1) To the extent that installation of DG does less to reduce an individual customer's costs under the tiered customer charge rate design proposal, it will make the economics of DG worse for that customer and will therefore discourage DER in a manner inconsistent with the statute. There is a balancing required in the REG Statute but as discussed above, the costs and complexity of the tiered customer charge proposal have not been demonstrated to be offset by other factors that would warrant its adoption.

Q. Finally, would you please explain why National Grid's rate design proposal does not represent a long-term solution to addressing the changing nature of the electricity system in Rhode Island?

A. As discussed above, the magnitude of the distribution cost allocation issue in Rhode Island does not warrant adoption of National Grid's rate design proposal. Rather, a more appropriate next step would be a process to explore how National Grid can make the investment needed to support the distribution, and more broadly the electricity, system needed to provide customers with safe, affordable and reliable service in an evolving future. Such a process should take advantage of National Grid's and other stakeholders' experience and expertise in Rhode Island

and other jurisdictions and take into account existing mechanisms and processes in Rhode Island. Then National Grid will be better situated to propose a new rate design, consistent with long established rate design principles and aligned with and supportive of that future.

Based on my long experience in the industry, particularly with respect to recognizing and responding to fundamental underlying technical and economic changes, I agree with much – but not all – of National Grid's description of the changing nature of the electricity system and the evolving role of the distribution utility. I also recognize the need for two way communications and power flow to be added to a largely one-directional distribution grid. However, distribution utilities such as National Grid face a conundrum. The number of kilowatt-hours used by most, if not all, customers is flat or declining because of the success of energy efficiency programs – both in delivering energy efficiency to customers but also transforming the market for lighting, appliances and other end-uses – as well as increasing customer adoption of distributed generation. At the same time, these changes require new investment by distribution utilities, which now largely recover the costs of the distribution grid on a kilowatt-hour basis.

That said, the appropriate response is *not* adoption of a rate design that simply shifts the balance of utility cost recovery from a variable kilowatt-hour charge to a fixed customer charge, which National Grid proposes. Rates based on demand or kilowatts are another type of variable charge to which customers can respond by changing their behavior if the tools to do so are reasonably available within a reasonable time frame – which brings us back to the need to invest in two way capabilities on the distribution grid.

III. Actions To Be Taken To Arrive At An Appropriate Rate Design Proposal

Q. What would be the next steps in Rhode Island to arrive at an appropriate rate design proposal?

A. There are several steps that should be taken in Rhode Island to lay the foundation for an appropriate rate design proposal that will achieve a balance between sending customers price signals that reflect the costs to serve them in a timely manner so that they can change their behavior and see the results of it, and providing distribution utilities with the opportunity to recover the just and reasonable costs of providing such service. Such rate design should also advance the evolution of the electricity system to meet customers' expectations and changing needs. These steps can provide important information for future policy processes and regulatory proceedings.

Fundamentally, deployment of the technical capability to measure customer demand and patterns of usage and then communicate related information to customers in a timely manner – i.e., two-way communications capability – is important for developing future rates. Customers also need to have tools available to them to react to this information, some of which will be captured in rates, and change their behavior if they choose to do so. In addition, grid side enhancements that provide the distribution utility with information about and enhance the capabilities of the distribution system to improve system efficiency and enable two way power flows are essential.

Enhancing the capability of the distribution system or modernizing the grid will require investments in the grid. Figuring out what those investments should look like will require changes to distribution planning, certain elements in the regulatory framework, new rate design and harnessing innovation.[4] To ensure that these investments will benefit customers, National Grid, with input from stakeholders and guidance from policymakers, will need to continue the work it has already begun in Rhode Island, as well as Massachusetts and New York

[4] NECEC has outlined these priorities in a white paper, "Leading the Next Era of Electricity Innovation: The Grid Modernization Challenge and Opportunity in the Northeast," which can be found at the link: http://www.necec.org/files/necec/Policy%20Documents/Grid%20Mod%20Report%20NECEC%20Aug.%202014.pdf and is attached in Appendix B.

and the UK, to identify not only the type and balance of investment but also the pace of investment that it can demonstrate will deliver benefits to customers that exceed the costs in order to justify it as just and reasonable to regulators.

Q. Are there specific next steps that you recommend?

A. Yes. National Grid should work with stakeholders in Rhode Island, including the parties in this proceeding, in a collaborative process to build a shared understanding of the steps to be taken to lead the evolution it describes in its pre-filed testimony. (Bates 15-17)

It can build on the work under way in the System Integration Rhode Island ("SIRI") process, take advantage of the information it is gathering from its Worcester, Massachusetts Smart Energy Solutions pilot (as referenced in N. Grid response to PUC 2-17, Bates 40), and the work it has done for its Massachusetts Grid Modernization Plan ("GMP") filing. It is interesting to note that of the four scenarios filed in its GMP, the only one with a benefit-cost ratio over 1.0 is the Advanced Metering Infrastructure ("AMI") scenario, but this is also the most expensive scenario. I expect that the Massachusetts regulators will delve into the details and Rhode Island can take the opportunity to learn from this as well.

Moving further to the west, the New York REV proceeding offers an additional source of information and experience. Among other things, New York will be investigating the metering functionality needed for demand-based rates and TVR, as well as the value that DER can provide to the distribution grid through its "LMP+D" process in 2016. The Track 2 Staff White Paper explains, "As applied here, LMP+D is a broader measure capturing the full value of DER, including energy (LMP) and the full range of values provided by distribution- level resources (D)"[5]

[5] Case 14-M-0101, "Staff White Paper on Ratemaking and Utility Business Models," New York Department of Public Service, July 28, 2015, page 75. See also Case 15-E-0407, "Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation", New York Public Service

IV. Recommendations

Q. What is your recommendation to the Public Utilities Commission?

A. I recommend that the Commission not approve National Grid's rate design proposal for the reasons discussed in my testimony.

The Company's filing is not consistent with the requirements of the REG Statute. It does not represent a balance among the factors the Commission is to take into account, most notably the "benefits of distributed energy resources" and "the general assembly's legislative purposes in creating the distributed generation growth program." In addition, it does not achieve "[s]implicity, understandability and transparency of rates to all customers, including non-net metered and net-metered customers" due to its complexity, nor has the Company demonstrated that its proposal is aligned with "cost causation principles." (RIGL §39-29.6-24)

The REG Statute requires that the Commission open a proceeding and that National Grid file a revenue neutral rate design filing. It does not require that a new rate design be adopted at this time and National Grid has not demonstrated that one is warranted. I recommend that National Grid instead be required to engage in a collaborative process with stakeholders, including the parties to this proceeding, in the context of exploration of system integration in Rhode Island and other existing processes to see how progress can be made toward a distribution grid with two-way communications and power flow capabilities, among other requirements for the evolving electricity system, and a rate design better suited to that system. Consideration should be given to demand based rates and TVR and other alternative rate designs that may require advanced metering functionality, along with other strategic

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Commission. October 16, 2015, page 9, discussing the elements of the value of D (generally for Distribution), which "can include load reduction, frequency regulation, reactive power, line loss avoidance, resilience and locational values as well as values not directly related to delivery service such as installed capacity and emission avoidance."

investment to develop the grid to meet customer expectations in a changing electricity system and continue to provide safe, affordable and reliable service for all Rhode Island customers.

Q. Does this conclude your testimony?

A. Yes.

Janet Gail Besser
Appendix A

JANET GAIL BESSER

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SUMMARY

Energy policy and regulatory strategy leader with proven track record of influencing debate on framework and rules to advance competition, efficiency, and clean energy and to support needed investment.

- Effective advocate with recognized expertise, credibility, and communications success.
- Broad industry experience as regulator, utility, developer, consultant, and consumer advocate.
- National, regional, and state experience and recognition.
- Particular strength in bringing together diverse groups in pursuit of common goal.

EXPERIENCE

NEW ENGLAND CLEAN ENERGY COUNCIL, Boston, MA — 2012-present

Vice President, Policy and Government Affairs

Lead policy development and advocacy activities of regional non-profit clean energy business and advocacy organization, coordinating across six state jurisdictions and at federal level, representing the business perspectives of investors and clean energy companies across broad spectrum of technologies and every stage of development.

- Led broad stakeholder coalition that resulted in successful enactment of 2012 Massachusetts energy law, expanding legislative and policy support for clean energy; negotiated compromise language and successfully advocated for passage of 2013 comprehensive Connecticut energy law, including new long term contracting provisions for clean energy sources across variety of technologies; successfully negotiated, with utility and environmental advocates, 2014 expansion of Rhode Island renewable energy growth program.
- Brought together and led "clean energy caucus" in groundbreaking Massachusetts regulatory proceeding to advance grid modernization, attracting broad support beyond clean energy community; leveraged Massachusetts experience, expertise and relationships in similar New York proceeding.
- Developed and led implementation of legislative and regulatory policy tracking, reporting and advocacy process for organization's members.
- Established state coordinators/partnerships, Government Relations Committee and recruited new members, enhancing effectiveness of organization's advocacy efforts.

NATIONAL GRID USA, Waltham, MA — 2004-2011

Vice President, Regulatory Strategy and Policy (2007-2011)
Vice President, Transmission Regulation and Commercial Services (2006-2007)
Vice President, Transmission Regulatory Affairs (2004-2005)

Led development of company regulatory strategy, coordinating policy positions across multiple state and federal jurisdictions to advance business objectives, ensure consistency, and enhance company influence on national, regional, and state energy policy and regulation.

- Developed and led implementation of regulatory outreach process for senior executive contact with key regulators, identifying company priorities leading to improved messaging for utilities across four states.
- Directed regulatory strategy to advance energy efficiency, renewable, clean, and advanced (smart) technology initiatives, achieving policy support and regulatory approvals for leading edge programs.
- Led development of widely disseminated and quoted white papers on role of transmission as a critical link in advancing renewable energy and competitive electricity markets, thereby shaping national debate.
- Effective expert witness on revenue decoupling as prerequisite to aggressive utility pursuit of energy efficiency. Recognized as expert on policy promoting energy efficiency, advising advocates and utilities nationally.
- Led cross-functional team and external consultants to assess benefits, costs, and risks of default service procurement strategy (affecting $3B+/yr), successfully gaining regulatory approval of preferred approach.

CONSULTING

At two firms below (Analysis Group and Lexecon), provided energy policy, regulatory, strategy, economic advice and analysis, business consulting, and litigation support to variety of clients, including generators, developers, utilities, large and small customers, specializing in regulatory framework, incentive regulation, retail/wholesale market structure, renewable and advanced technologies, transmission, energy efficiency, and environmental issues.

ANALYSIS GROUP, INC., Boston, MA 2003-2004

Vice President

- Led economic, technical, and policy analysis for national transmission forum and wrote report demonstrating need for transmission, identifying barriers to investment and options for overcoming them.
- Identified opportunities for existing and future development of renewable energy facilities by analyzing implications of locational marginal pricing.
- Provided analysis and expert witness testimony for several clients on economic and policy foundation for contracts resulting from federal and state law and regulation promoting competitive power generators, and on valuation of power plants post-industry restructuring.

LEXECON INC., Cambridge, MA 2000-2003

Senior Vice President (2001-2003)

Vice President (2000-2001)

- Achieved consensus among diverse group of generators and marketers on framework for New England Regional Transmission Organization, providing technical and analytic support for FERC filings and successfully eliciting support of other key stakeholders.
- Advised generation company on wholesale energy and capacity market design, transmission and ISO issues, federal and state market rules, siting and environmental regulation to enhance participation in regional markets.
- Assisted large customer in negotiations with electric utilities to reduce costs, providing strategic advice, rate analysis, and evaluation of self-generation options.
- Provided support for transmission development to several clients through economic, technical, and policy analysis on planning, need, and siting of transmission, including impacts of non-wires alternatives.

MASSACHUSETTS DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY 1995-2000

Formerly and now Massachusetts Department of Public Utilities Boston, MA

Chair (1998-2000)

Acting Chair (1997-1998)

Commissioner (1995-1997)

Gained national recognition for MA, leading regulatory initiatives to restructure electric industry to introduce competitive wholesale generation and retail electricity markets while promoting energy efficiency and renewable energy.

- Initiated coordination with state environmental regulatory agency to align energy and environmental policy; led national effort to promote similar coordination in other states.
- Promoted incentive regulation, including key framework that led to adoption of performance-based rate plans and service quality standards for several electric, gas, and telecommunications companies.
- Established new policy to encourage and oversaw first utility mergers (two electric and three gas) in MA in over 20 years to capture efficiencies and reduce costs for customers.
- Led introduction of competition and unbundling in natural gas and telecommunications industries, improving efficiency and providing benefits to customers.

NATIONAL INDEPENDENT ENERGY PRODUCERS, Washington, DC 1993-1995

Policy Director

- Influenced federal and state policy and regulatory framework through regulatory filings and white papers to establish robust competitive generation markets to enhance efficiency and investment opportunities.
- Successfully coordinated and developed consensus among members of national trade association, with varying interests and business models, to advance competitive wholesale and retail markets.

MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES, Boston, MA 1992-1993

Director, Electric Power Division

- Implemented integrated resource planning rules to promote energy efficiency and power purchase contract policy to ensure cost-effective and adequate supply for utility customers.
- Led state and regional efforts to coordinate energy and environmental policy to reduce emissions and advance clean energy resources while ensuring resource adequacy.

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION, Concord, NH 1988-1992
Manager, Energy Planning (1991-1992)
Utility Analyst for Energy Planning (1988-1991)

- Developed and implemented integrated resource planning process and rules for electric and gas industries, leading to first utility energy efficiency programs in the state.

MASSACHUSETTS EXECUTIVE OFFICE OF ENERGY RESOURCES, Boston, MA 1985-1988
Director, Electricity Planning and Policy Development (1987-1988)
Senior Electricity Economist (1985-1986)

- Developed and produced State Annual Forecast of Energy Resources, the first systematic and analytically supported forecast of MA energy demand, resources and impacts of energy policy.
- Drafted and played significant role in developing consensus among six New England states to support Plan for Meeting New England's Electricity Needs.

RELEVANT PRIOR EXPERIENCE

Worked as Assistant to Director of Development for Essex Development Associates, Inc., Concord, NH assessing feasibility and securing regulatory approvals of potential small hydroelectric projects. Began career as advocate for low-income energy customers at Belknap-Merrimack Community Action Programs, Concord, NH.

EDUCATION

M.P.P., HARVARD UNIVERSITY - JOHN F. KENNEDY SCHOOL OF GOVERNMENT, Cambridge, MA

B.A., **Political Science**, *magna cum laude*, WILLIAMS COLLEGE, Williamstown, MA

RECENT PROFESSIONAL ACTIVITIES

Member, Advisory Committee to MITei Utility of Future Study, November 2014-
Member, PowerOptions Board of Directors, 2011-present; Chair, Strategic Planning Committee, 2013-present
Lecturer, Energy Policies for a Sustainable Future, MIT, 2007, 2009-2011
Lecturer, Green Management Consulting, Babson College, 2009, 2011
Member, State Energy Efficiency Action Network Utility Motivation Working Group, 2010-2011
Member, New York State Climate Action Plan Integration Advisory Panel, 2009-2010
Member, Ceres 21st Century Utility Futures Group, 2009
Member, National Electricity Forum Working Group, 2007-2009
Founding Member and officer, WIRES (Working Group for Investment in Reliable and Economic Electric Systems), 2007
Chair, Green Buildings Advisory Committee, Massachusetts Renewable Energy Trust, 2002-2005
Member, National Association of Regulatory Utility Commissioners (NARUC) Board of Directors, 1999-2000
Member, Ad Hoc Committee on Electric Industry Restructuring, NARUC, 1998-2000
Vice Chair, Energy Resources and the Environment Committee, NARUC, 1997-1999; Member, 1995-2000
President, New England Conference of Public Utility Commissioners (NECPUC), 1997-1998; Member, 1995-2000
Member, The Energy Foundation Utility Futures Group, 1995-2000
Member, Harvard Electricity Policy Group, 1995-2003, 2007-2011
Member, Electric Power Research Institute (EPRI) Advisory Council, 1995-1998
Member, New England Chapter, International Association for Energy Economists, 1988-2004

PUBLICATIONS, REPORTS, AND ARTICLES

"Leading the Next Era of Electricity Innovation: The Grid Modernization Challenge and Opportunity in the Northeast" (with Peter Rothstein and Jesse Jenkins), NECEC Institute White Paper, August 2014.

"Transmission and Wind Energy: Capturing the Prevailing Winds for the Benefit of Customers," National Grid Paper, September 2006.

"Transmission: The Critical Link – Delivering the Promise of Industry Restructuring to Customers" (with Joe Rossignoli and Mary Ellen Paravalos), *The Electricity Journal*, Volume 18, Issue 5, 2005.

"Transmission: the Critical Link," National Grid Paper, June 2005.

"Shining Light on the Blackout" (with Jeffrey Tranen), *The Energy Daily*, September 24, 2003.

"The Political Economy of Long-Term Generation Adequacy: Why an ICAP Mechanism Is Needed as Part of Standard Market Design" (with Susan F. Tierney and John Farr), *The Electricity Journal,* August/September 2002.

"Activating Ontario's Capacity Market: Design and Implementation Issues" (with Susan F. Tierney and John Farr), prepared for Sithe Energies, Inc., October 24, 2001.

White paper on "Ensuring Sufficient Capacity Reserves in Today's Energy Markets" (with John Farr and Susan F. Tierney), prepared for submission as part of comments filed by Sithe Power Marketing LLC, Sithe New England Holdings, and FPL Energy LLC, in FERC Docket No. EX01-1-000, October 17, 2001.

"The Rationale and Need for Capacity Obligations and a Capacity Market in a Restructured Ontario Electricity Industry" (with Susan F. Tierney and John Farr), prepared for Sithe Energies, Inc., September 27, 2001.

"The Competitive Generation Market Has Been Assumed, Not Proven" (with Stephen Lewis), *The Electricity Journal*, April 1995.

"Is Competition Here? An Evaluation of Defects in the Market for Generation" (with Merribel S. Ayres, Harrison Wellford, and Scott Hempling), National Independent Energy Producers, Washington, DC, January 31, 1995.

"Utility Environmental Impacts: Incentives and Opportunities for Policy Coordination in the New England Region," US EPA CX817494-01-0, RCEE Core Group, June 1994.

"The State Annual Forecast of Energy Resources 1987-1997: Fueling the Future," principal author and editor, The Executive Office of Energy Resources, Commonwealth of Massachusetts, December 1987.

SELECTED CONSULTING EXPERIENCE

- **Consumer Energy Council of America**
  Provides economic, technical and policy support to Transmission Infrastructure Forum investigating transmission needs, barriers to investment and options for overcoming these barriers. (2004)

- **Waste-to-energy facility**
  Provides economic analysis and expert witness testimony for litigation relating to valuation of power plant and how it had been affected by electric industry restructuring. (2003-2004)

- **New Hampshire Charitable Foundation**
  Provided economic analysis and verification of revenues of series of hydropower facilities pursuant to settlement of federal relicensing review. (2003)

- **Duke Power**
  Provided expert advisory services relating to state rate-making and other regulatory practices. (2003)

- **Retail energy service affiliate of large oil company**
  Provided strategic advice on and assessment of regulatory reaction to current natural gas supply conditions and price forecasts. (2003)

- **Electric utility company**
  Provides economic analysis and regulatory support to major electric utility regarding ability of distributed generation to defer need for transmission investment. (2002-2004)

- **Electric utility company**
  Provided strategic advice and regulatory support to electric utility relating to role of company in changing retail electricity markets. (2002-2003)

- **Electric utility company**
  Provided strategic advice to electric utility regarding nature of and opportunities in competitive retail electricity markets. (2002)

- **Regional independent system operator**
  Provided strategic advice on regional transmission organization strategy. (2002)

- **Law firm**
  Provided regulatory and policy advice, economic analysis, and expert witness testimony for litigation relating to power purchase contract terms. (2002)

- **Cogeneration facility**
  Provided economic analysis, regulatory support, and expert witness testimony on power purchase contract issues arising from electric industry restructuring. (2001-2002)

- **Electric utility company**
  Provided strategic advice and regulatory support to electric utility relating to proposals for incentive regulation in a major rate case and on an ongoing basis. (2001-2003)

- **Duke Energy Corporation**
  Provided analysis on strategic issues in gas and electric regulatory policy for Duke Energy's corporate office, including with regard to code of conduct issues, wholesale competition, and regional transmission organization policy. (2001-2002)

- **Massachusetts Technology Collaborative**
  Provided strategic, economic and technical assistance in support of the Massachusetts Technology Collaborative's Renewable Energy Trust program. (2001-2004)

- **NERPPA (New England Renewable Power Producers Association)**
  Provided analysis of implications of implementation of locational marginal pricing ("LMP") on existing and the development of future renewable energy facilities. (2001)

- **Electric distribution company**
  Provided regulatory and strategic advice regarding various regulatory requirements related to retail access and provision of default services. (2001)

- **Saint Gobain Co.**
  Provided analysis of natural gas price trends, forecasts, and ability to anticipate gas price spikes. (2001)

- **A major pipeline with operations in 14 states**
  Provided strategic, economic and technical support, including rate and tariff analysis and evaluation of self-generation options, in negotiations with electric utilities to reduce costs. (2000-2001)

- **American National Power, Calpine, El Paso, NRG Energy, Sithe, Southern Energy**
  Worked with diverse group of generators and marketers to achieve consensus on framework for a New England RTO; provided technical and analytic support for development of a proposal to FERC based on framework; assisted initial group in eliciting support of other key stakeholders, including state regulators, policymakers and consumer groups (both business and residential), as well as additional generators and marketers. (2000-2001)

- **Arkansas Electric Distribution Cooperatives and Arkansas Electric Cooperative Corporation**
  Provided expert witness support and analysis on economic and public policy issues associated with various aspects of wholesale and retail competition in Arkansas. (2000-2002)

- **Sithe Energies, Inc.**
  Provided strategic advice and regulatory support on a variety of issues (market design and analysis, transmission and ISO issues, federal and state market rules, legislation, siting, environmental strategy) relating to the company's participation in the New England, New York, Ontario and PJM markets. (2000-2001)

- **HEFA Power Options**
  Provided strategic advice regarding wholesale electricity market and supply procurement process for aggregation of large retail purchasers of electricity in Massachusetts. (2000-2003)

- **Major real estate development company**
  Provided strategic support relating to electric utility infrastructure affecting various real estate development projects. (2000-2001)

- **State independent power producers organization**
  Evaluated competitiveness of bids received to build new capacity in response to a utility RFP. (2000)

- **State energy office and environmental regulatory agency**
  Provided strategic advice on economic impacts of application and timing of new environmental regulations pertaining to power plants slated for auction. (2000)

- **Conectiv**
  Provided strategic wholesale market analysis and support for procurement of supplies for distribution utility company's provision of Basic Generation Services to retail customers. (2000)

TESTIMONY ON BEHALF OF CLIENTS

- **Generation Developer**
  Confidential expert report and oral testimony in arbitration proceeding. 2002, 2003.

- **New England Renewable Power Producers Association**
  Before the Federal Energy Regulatory Commission, New England Power Pool and ISO New England, Inc., Docket No. ER01-2329, Joint Affidavit (with Paul J. Hibbard), July 3, 2001.

- **Colonial Pipeline Company**
  Before the Public Service Commission of the State of Mississippi, Docket No. 00-UA-925, In re: Joint Petition of Entergy Mississippi, Inc., Entergy Corporation, FPL Group, Inc., and WCB Holding Corp. for Approval of Transfer of Controlling Interest in the Corporate Stock of Entergy Mississippi, Inc., Resulting from Merger Transaction; Prepared Direct Testimony on Behalf of Colonial Pipeline Company, March 2, 2001.

- **Arkansas Electric Distribution Cooperatives**
  Before the Arkansas Public Service Commission, In the Matter of a Generic Proceeding to Establish Uniform Policies and Guidelines for a Standard Service Package, Prepared Joint Reply Testimony (with Susan F. Tierney), July 21, 2000; Prepared Joint Surreply Testimony (with Susan F. Tierney), August 3, 2000; Oral Testimony, August 8, 2000.

TESTIMONY ON BEHALF OF THE COMMONWEALTH OF MASSACHUSETTS AND THE STATE OF NEW HAMPSHIRE

Before various Massachusetts legislative committees on electricity industry restructuring, energy policy (including mergers, incentive regulation, and codes of conduct), energy facilities siting, telecommunications, and budget matters, 1997-1999.

Before the New Hampshire Public Utilities Commission on Eastern Utilities Associates' attempt to acquire Unitil Service Corporation, 1991.

Before the New Hampshire Public Utilities Commission on Northeast Utilities-Public Service of New Hampshire merger, 1989.

Before the Federal Energy Regulatory Commission on New England Power Pool Performance Incentive Program, 1989.

Before the Massachusetts Department of Public Utilities in its investigation of 1987 reliability problems in New England, spring 1988.

TESTIMONY ON BEHALF OF NATIONAL GRID

Before the Massachusetts Department of Public Utilities in its investigation on its own motion of rate structures that will promote efficient deployment of demand resources (decoupling), DPU 07-50, September 2007.

TESTIMONY ON BEHALF OF NECEC

Before the Massachusetts Department of Public Utilities in its investigation on its own motion into modernization of the electric grid, DPU 12-76, February 2014.

Janet Gail Besser
Appendix B

Leading the Next Era of Electricity Innovation:

The Grid Modernization Challenge and Opportunity in the Northeast

Authors:

Peter Rothstein

Janet Gail Besser

Jesse Jenkins

necec Institute

August 15, 2014

Acknowledgements

Drawing on NECEC's work on the Massachusetts Grid Modernization Steering Committee and other grid modernization efforts in the Northeast, this paper examines the benefits of grid modernization and a 21st century electricity system and the policy and regulatory framework needed to advance them.

This is an independent report by NECEC, supported by funding from the Energy Foundation. It was written by NECEC President Peter Rothstein, NECEC VP of Policy and Government Affairs Janet Gail Besser and Jesse Jenkins. (Jenkins is a researcher, analyst, and writer with expertise in energy and climate change, electric power systems, energy policy, and innovation policy. He is currently an MIT PhD student researching the interaction between policy, regulation, and technological change in the electricity sector, including research with the MIT Energy Initiative's Utility of the Future project.)

NECEC is a regional non-profit organization representing clean energy companies and entrepreneurs throughout New England and the Northeast through programs and initiatives that help clean energy businesses at all stages of development to access the resources they need to grow. NECEC's mission is to accelerate the region's clean energy economy to global leadership by building an active community of stakeholders and a world-class cluster of clean energy companies.

NECEC is the umbrella organization for the New England Clean Energy Council, which is the lead voice for hundreds of clean energy companies across New England, influencing the energy policy agenda and growing the clean energy economy, and the NECEC Institute, which leads programs across the Northeast that support Innovation & Entrepreneurship, Cluster and Economic Development and Workforce Development.

Cover image by Ontario Ministry of Energy.

Executive Summary

Introduction

The electric power sector in the Northeast United States stands at an inflection point. Distributed energy resources—from increasingly affordable solar panels and electric vehicles to internet-enabled smart devices and building systems and advanced power electronics—are creating both new demands on the grid and new opportunities to unlock system-wide efficiencies. This proliferation of distributed resources is challenging the operation of a 20th century electricity system built for one-directional delivery of electricity as two-way power flow is becoming increasingly common. At the same time, policy makers and grid users are demanding even more from our electricity system.

These new expectations for a cleaner, more resilient, and more distributed 21st century grid come against the backdrop of flat or declining demand for electricity across the region and growing cost pressures associated with the need to replace many components of the region's aging transmission and distribution infrastructure. The combination of new demands on utilities, substantial capital investments required to maintain current functions and meet new needs, and flagging electricity demand presents an almost untenable challenge for the region's traditionally regulated distribution utilities. Regulators and utilities must evolve to adapt to this changing world.

To build a 21st century electricity system that is cleaner, more efficient, more resilient, and capable of delivering affordable rates that keep the region competitive in the global economy, the Northeast must once again lead the next era of innovation in the electricity sector. This means embracing a modern grid that harnesses advanced energy and communications technologies to better integrate renewable and distributed resources, improve resiliency, and deliver system-wide efficiencies. For utilities, it means a new business model as the active operator of a dynamic distribution grid. For regulators, it means forward looking regulation to unlock markets, spur innovation, and harness competition on the customer and retail side of the market to deliver better performance, lower electricity costs, and a cleaner environment for the region.

Priorities for Policy, Regulatory, and Business Innovation

Policy makers, regulators, and utility and advanced energy industry leaders across the Northeast need to work together to craft a shared vision for the future of the region's electricity system. In *Leading the Next Era of Electricity Innovation*, NECEC focuses on four key priorities to seize the grid modernization opportunities and put the Northeast on a pathway to a truly 21st century electricity system:

Planning for Grid Modernization: Utilities should develop and implement forward-looking business plans, including distribution system investment plans, to make the transition from a commodity electricity delivery business model to a business model in which the utility serves as a distributed platform system operator that integrates distributed energy resources, enables bidirectional markets for electricity services and is a hub for grid data and information services, while continuing to provide the safe, reliable and affordable service customers expect.

A New Forward Looking, Outcomes-based Regulatory Framework: Regulators across the Northeast should pioneer a forward-looking, outcomes-based approach to regulating distribution utilities. First, regulators should work with the utility and stakeholders to define the set of outcomes the utility is expected to deliver in the years ahead. Second, mechanisms should be employed to ensure that both utilities and ratepayers benefit from cost-saving efficiencies. Third, regulators should define outcome-based incentives that reward utilities for delivering value to, and enabling value creation by, network users. Such a regulatory framework would support investments in a modern grid with enhanced reliability, resiliency, and environmental performance. It would also align incentives to fully integrate distributed energy resources, encouraging utilities to view DER owners as both customers and system users with unique needs to be served and new partners in efficient operation of system.

Efficient and Fair Rates: Regulators must also develop improved electricity tariffs or rates that set fair prices for the range of services distribution utilities deliver and ensure recovery of allowed costs, compensate distributed energy resources and electricity users for the services they provide, and send market signals to network users to optimize system-wide efficiency. Rates should send accurate signals about the value of consuming or producing electricity at different times and locations and under different system conditions, enabling customers to optimize their use of the electricity system. They should also ensure utilities have a reasonable opportunity to recover all allowed costs in a fair and non-discriminatory manner. Finally, rates should be designed to further state and regional policy objectives, such as incentivizing energy efficiency or distributed energy adoption. Accomplishing these three objectives may require balancing among them so that policy goals are achieved in a way that preserves efficient price signals and maintains adequate cost recovery.

Unlock Innovation: To become the central platform of a 21st century electricity system, distribution utilities across the Northeast must continually adapt to new technologies and changing energy needs, becoming active partners with the region's advanced energy companies and innovative system integrators of new technologies. Regulators should support these innovation efforts by allowing utilities to establish budgets for demonstration, testing, and integration and share accelerated learning about the performance, cost, and capabilities of these new technologies. These innovation activities would be consistent with the modern utility's role as an active system operator and integrator of distributed and advanced energy technologies and would ensure that the Northeast's utilities will be positioned to take advantage of cutting edge technologies and capabilities.

Seizing the Grid Modernization Opportunity

The challenges arising from the rapid evolution of electricity system needs and technologies are by no mean unique to the Northeast. But by acting with bold initiative and leading the regulatory and policy innovations necessary to seize the grid modernization opportunity, the Northeast can position itself at the forefront of a new era of electricity innovation. A modern, 21st century electricity system can deliver real economic, energy, and environmental benefits for the region by enabling a more efficient, flexible and resilient, grid that gets cleaner year after year. The time is now to seize the grid modernization opportunity in the Northeast and to build a 21st century electricity system that will position the region for economic competitiveness, support the growth of our advanced energy economy, improve environmental performance and deliver real cost savings for citizens across the region.

Introduction

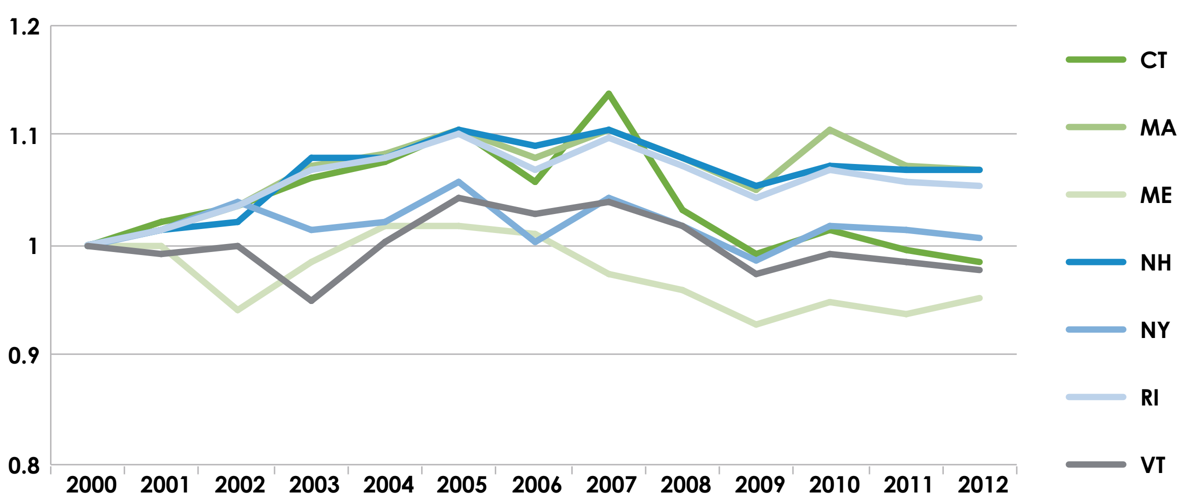
The electric power sector in the Northeast United States stands at an inflection point. Distributed energy resources, from increasingly affordable solar panels and electric vehicles to internet-enabled smart devices and building systems and advanced power electronics, are creating both new demands on the grid and new opportunities to unlock system-wide efficiencies. The increased performance of these advanced energy technologies is expanding capabilities for on-site power generation, optimization of daily energy consumption, and even supply of new services from customers and third parties to grid operators. The proliferation of distributed resources is simultaneously challenging the operation of a 20th century electricity system built for one-directional delivery of electricity from central station generators down through transmission and distribution voltages to end-use customers. Two-way power flow is becoming increasingly common on electricity distribution circuits and demand response and time-varying pricing are making electricity customers more dynamic than ever before. Electric utilities must now adjust operational practices to accommodate a growing variety of distributed energy resources and modernize their planning processes to fully integrate and take advantage of the new range of capabilities offered by these advanced energy technologies. Utilities must evolve their business model to adapt to this changing world.

At the same time, policy makers and grid users are demanding even more from our electricity system. Electricity is now more central to our daily lives than ever before, and recent severe weather events across the Northeast have highlighted the need for a more resilient electricity system capable of both better withstanding shocks and recovering more rapidly from outages. The proliferation of internet and communication technology has also enabled unprecedented connectivity, making everyone from consumers to public officials accustomed to widespread access to up-to-the-minute information on all aspects of our modern lives. We now expect no less from our electric utilities and retail suppliers. Finally, the Northeast has led the world in recognizing and acting on the critical importance of a more economically efficient and environmentally sustainable electricity system. From driving aggressive energy efficiency and renewable energy priorities, leading restructuring of competitive wholesale power markets, and launching the nation's first regional market-based CO_2 reduction program for power plants, the Northeast is demanding and delivering an ever-cleaner and more efficient grid.

These new demands and expectations for a cleaner, more resilient, and more distributed 21st century grid come against the backdrop of flat or declining demand for electricity across the region (see Figure 1) and growing cost pressures associated with the need to replace many components of the region's aging transmission and distribution infrastructure. Nationwide, the American Society of Civil Engineers estimates that simply maintaining our existing electricity infrastructure will require $673 billion in new investment by 2020.[1] New York utilities alone may need to make $30 billion in investments to replace aging infrastructure over the next decade.[2] This combination of new demands on utilities, substantial capital investments required to maintain current functions and meet new needs, and flagging electricity demand presents an almost untenable challenge for the region's traditionally regulated distribution utilities. This challenge is rooted in the traditional cost of service regulatory framework and a utility business model centered on the delivery of electricity to customers who are not considered active market participants.

The Northeast led restructuring and launched independent transmission system operators to unlock competitive, efficient wholesale power generation markets. However, the age-old regulatory paradigm based on after the fact review of costs to provide service and allowed returns on investment still persists for electric distribution utilities across the region, which operate largely as they have for the past century. While this regulatory framework worked reasonably well in the past, it will not suffice for a truly 21st century electricity system. This input-focused, after the fact review provides poor incentives for utilities to seek cost-saving efficiencies and makes it challeng-

Figure 1. Electricity demand in Northeast states
(demand levels expressed relative to 2000 demand)[3]



ing for regulators to reward superior performance. The backwards-looking nature of this review also causes a delay between utility investments and recovery of costs and creates a risk that regulators will disallow cost recovery. This risk becomes acute for any investments that depart from previously accepted practice. Particularly at a time of slowly growing or declining electricity demand, these features can impede necessary investments in grid modernization, stifle innovation, and hamstring the utility's ability to adapt to and harness rapidly evolving technology.

Likewise, delivery of electricity is quickly becoming just one of many core responsibilities of the modern distribution utility. Yet the utility business model remains tied to electricity delivery and costs are recovered largely through volumetric tariffs on a per kilowatt-hour basis. While decoupling mechansims and efficiency incentive programs across much of the region may address utility reluctance to promote energy efficiency and distributed generation, flat or declining electricity demand and growing investment needs still mean rising prices for electricity delivery under today's business and regulatory model. That could lead to an unsustainable cycle of rising electricity prices across the region and, as distributed energy resource costs fall further, a growing possibility that more and more users will generate most of their own power, invest in deep energy efficiency measures to drastically cut and manage their demand, or even disconnect from the grid entirely. This is the "disruptive challenge" for electric utilities now being discussed across the country.[4] Even if widespread grid defection remains a hypothetical prospect, the utility business model today provides little incentive for utilities to see distributed energy resources as important and valuable customers, let alone potential partners in the operation of a modern grid. Likewise, today's electricity rates do not fairly or efficiently price the electricity services utilities deliver to customers nor compensate those customers for the services they increasingly provide to the electricity system.

The grid modernization challenge and opportunity for the Northeast

To build a 21st century electricity system that is cleaner, more efficient, more resilient, and capable of delivering affordable rates that keep the region competitive in the global economy, the Northeast must once again lead the next era of innovation in the electricity sector. This means embracing a modern grid that harnesses advanced energy and communications technologies to better integrate renewable and distributed resources, improve resiliency, and deliver system-wide efficiencies. But it also means leading in regulatory innovation to once again unlock markets, spur innovation, and harness competition on the customer and retail side of the market to deliver better performance, lower electricity costs, and a cleaner environment for the region.

The Northeast showed the nation how to get restructuring of wholesale power markets right, and the region pioneered policies to align utility, third party, and customer incentives to unlock energy efficiency opportunities. This leadership delivered clear results (see box on page 4), including consumer cost savings, improved regional economic competiveness and environmental quality, and new business opportunities. Today, policy makers, regulators, and utilities in the Northeast can once again lead in the restructuring and modernization of the distribution sector, engaging all stakeholders – customers, distribution companies, distributed energy resource providers, and other non-utility actors – in the delivery, integration, and innovation of electricity services. In particular, to unlock grid modernization, the regulatory framework should be forward-looking and provide strong incentives for distribution utilities to continually innovate and partner with grid users and third parties to deliver improved performance, unlock system-wide efficiency and cost savings, and create a platform for an increasingly diverse and distributed electricity sector.

The Rewards of Leadership: Electricity Restructuring in the Northeast

Analysts estimate that the restructuring of wholesale electricity markets in New England spurred significant improvements in the operational performance of the region's power plants, reduced emissions rates from electricity generation, and saved electricity consumers a cumulative \$6.5-7.6 billion from 1998-2005.[5] Utilization rates for the Northeast's nuclear power plants increased substantially after restructuring, and outage rates for fossil power plants fell. According to detailed studies from the Analysis Group, restructuring reduced wholesale generation costs by 5 percent in New York and 2 percent in New England, producing net economic savings on the order of hundreds of millions of dollars annually.[6]

At the same time, electric distribution utilities should embrace their evolving role as the active operator of a dynamic distribution grid, the pivotal connection between network users and the bulk power system, and the platform enabler of an innovative range of products and services harnessing distributed energy resources. This will require changes to both regulation and utility business practices and distribution system planning.

In the 21st century power system, optimizing electricity demand should no longer be a practice reserved for times of peak demand and emergencies but rather become a cost-effective tool in the utility's arsenal for day-to-day management of the grid. Likewise, distributed energy resources should not be viewed as backup or standby resources for when the grid fails or as passive users of the system, as utilities view most solar systems today. Instead, wherever cost-effective, these distributed energy resources – including distributed generation, storage, energy efficiency, demand response, and smart optimization of building systems and other loads – should be active participants in the 21st century grid and related markets for electricity services. The result will be a more competitive and diverse marketplace, more responsive and efficient optimization of demand, and new tools for independent system operators (ISO), distribution utilities and competitive aggregators[7] of distributed energy systems[8] to manage the power system, reduce congestion and price volatility, integrate renewable energy resources, and encourage investments in a more efficient and cleaner electricity system.

The time for leadership is now

The context in which electric utilities operate is already changing, and only a forward-looking and holistic approach to grid modernization can unlock the full benefits of a 21st century electricity system. Continuing business-as-usual has its own risks and the cost of doing nothing is not zero.

Utilities across the region are investing millions of dollars in network infrastructure every day. These utilities need a comprehensive, modern regulatory framework to guide those investments, ensure they can secure affordable finance, and reward them for cost-saving and performance-enhancing innovations. They also need to modernize their distribution planning processes to integrate new technologies on both sides of the meter, as well as distributed energy

> "In the 100+ year history of the electric utility industry, there has never before been a truly cost-competitive substitute available for grid power. Over the next few years, however, we believe that a confluence of declining cost trends in distributed solar photovoltaic (PV) power generation and residential-scale power storage is likely to disrupt the status quo. We see near-term risks to credit from regulators and utilities falling behind the curve."
>
> **– Barclays credit strategy team, May 2014**

resources. Finally, utilities need to define their roles differently as managers and operators of a system platform that enables a broad range of innovative new applications even as they continue to provide safe, reliable and affordable delivery of electricity and explore opportunities for new products and services.

The world is changing for utility customers as well. Electricity users are investing today in new building energy systems, purchasing their own renewable generation, backup generators and batteries, and considering new ways to manage their energy use, all amidst growing uncertainty about the resilience of the Northeast grid and concerns about the rising and volatile cost of energy. As much as users of telecommunications services are no longer simply passive consumers of broadcast media but rather engaged in a diverse range of communications channels and active in content creation (blogging, tweeting, creating and sharing video, photos and more), electricity system users are becoming increasingly active participants in the production, consumption, and trade of various electricity products and services.

Likewise, with the performance of distributed energy technologies improving and costs falling, advanced energy companies across the region are poised to help build a more efficient and resilient grid and contribute to clean energy and environmental policy objectives. Yet these innovative companies need comprehensive regulatory reforms, clear markets, active utility partners, and a modern platform infrastructure to unlock their full potential and deliver new products and services to electricity users and grid operators.

Finally, Wall Street analysts are warning that maintaining the *status quo* could imperil the financial viability of U.S. utilities. Bank of America and British banking giant Barclays both recently downgraded the credit ratings of U.S. electric utilities who are struggling to adapt to rapidly evolving market conditions and a static regulatory compact,[9] and Goldman Sachs, Citigroup, and others have warned of the increasingly competitive nature of distributed energy technologies.[10] This is about more than the fate of utility shareholders, as the credit worthiness of utilities directly affects the cost of capital for necessary network repairs, upgrades, and expansions, translating to higher prices for the region's electricity customers, slower investment in grid modernization, and declining regional economic competitiveness.

Policy makers, regulators, and utility and advanced energy industry leaders across the Northeast need to work together to craft a shared vision for the future of the region's electricity system.[11] A shared vision should facilitate agreement on the objectives of grid modernization, the policy and regulatory changes needed to open the distributed end of the market to innovation and competition, on the evolving roles, responsibilities and business model of the regulated utility, and on the roles and responsibilities of customers and other key stakeholders in the 21st century electricity system.

Priorities for Policy, Regulatory, and Business Innovation

Seizing the grid modernization opportunity requires regulatory innovation and policy leadership across the Northeast. This paper outlines a set of policy, regulatory, and business priorities that can put the region on the pathway to a truly 21st century electricity system by unlocking markets, promoting competition and innovation, and establishing clear rules that enable new business models for utilities and third parties alike, all in the service of new options and improved service for customers and a cleaner energy system.

This paper recommends a focus on four key priorities: planning, a forward-looking regulatory framework, rate design, and innovation. **First**, utilities should develop and implement forward-looking business and distribution system investment and operation plans that outline how they will integrate distributed energy resources and harness advanced energy technologies to deliver value to electricity system users. **Second**, regulators must modernize the regulatory process and adopt a new forward-looking framework that rewards improved performance and system-wide efficiency and aligns utility incentives to integrate distributed energy resources and the services these advanced energy technologies can provide to the grid. **Third**, rate design and pricing should be updated to ensure prices for the use of the electricity system are fair and efficient and that distributed energy resources are fairly compensated for the services they provide to the grid. This includes designing improved rates for use of and services provided to the distribution network by both electricity customers and distributed energy resources, such as time-varying rates that can send efficient signals for the optimization of electricity demand, as well as establishing open access data platforms accessible by customers and third parties. **Fourth**, utilities must become active partners in and enablers of advanced energy innovation. Regulations and policy should encourage utilities to increase investments in long-term innovation and to constantly evolve and adapt to new technologies to meet 21st century energy needs.

Distributed Energy Resources: New Partners at the Edge of the Modern Grid

Until now, distributed energy resources have often been viewed as creating new challenges for distribution network operators. However, these resources can in fact be valuable new partners for the efficient operation of the modern grid. By incentivizing solar PV installations on heavily-loaded distribution lines, utilities can help reduce losses on those lines by up to 8 percent.[12] *Similarly, smart inverters used to connect solar panels, fuel cells, electric vehicles, and stationary batteries to the grid can help utilities optimize system voltage and reactive power consumption, which can reduce peak demand on distribution lines by 1 to 2.5 percent on average and by 5 percent or more on some lines.*[13] *Networked together into a grid-connected microgrid, distributed energy resources can also help utilities keep the lights on when the larger power system fails. A microgrid built and operated by San Diego Gas and Electric (SDG&E) in Borrego Springs, California—incorporating distributed generation and storage and automated network switching—automatically restored power to 1,060 customers, including the town's entire downtown business area, within hours after a severe storm knocked out power. It took 25 hours to restore service to the remainder of the town's 2,780 customers. Ultimately, SDG&E believes microgrid-integrated distributed energy resources and price-driven load management can also help cut peak demand by more than 15 percent, allow more power to be delivered through existing infrastructure, and reduce the need to expand the grid in the future.*[14]

Planning for Grid Modernization

The modern regulatory process should begin with utility development and analysis of distribution system and business plans that chart a path to a 21st century grid. These plans should outline how utilities will modernize their grids, integrate distributed energy resources, adopt advanced energy and communications technologies, and deliver new value for electricity system users, while continuing to provide the safe, reliable and affordable service customers expect. Utilities need to plan to embed communication and visibility capabilities across the distribution system and establish the platform interfaces to communicate and integrate with customer and third-party resources. This includes both "grid-facing" and "customer-facing" technologies that enable two-way communication. The ISOs and distribution utilities need enhanced visibility over electricity customers and distributed energy resources to better integrate them, and network users need better access to price signals and timely information about system conditions to optimize their energy and network use.

Utilities should also plan to encourage distributed resources to locate and operate in ways that are most valuable to the grid, electricity customers, and the region's economic, clean energy and environmental policy goals. Plans should indicate how the utility will integrate and take advantage of the full range of capabilities distributed energy resources offer for system planning and grid operations. Well-placed and operated distributed resources may help distribution utilities avoid or defer costly network upgrades, manage system voltage and reactive power, and even deliver power to meet local demand when the higher-voltage power system fails. However, distributed energy resources can only deliver their full value if utilities embrace these resources both as another core user of the system and a new set of partners for efficient grid operations.

Utilities need to embrace new business models to thrive in a 21st century electricity system

In outlining their business plans, utilities should embrace a transition from a commodity electricity delivery business to a distributed platform system operator, integrator of distributed energy resources, enabler of bidirectional markets for electricity services, and hub for grid data and information services. **Much like ISOs are the backbone of efficient wholesale power markets, the distribution utility's new role includes modernizing, operating, and continually improving a resilient distribution system platform that is capable of evolving to meet the changing needs of customers, system operators, and economic, energy, and environmental policy in the 21st century.** The distribution utility will also be the creator or enabler of markets for the local exchange of basic, enhanced, and competitive energy services, including both local generation and consumption of electricity and the provision of capacity, energy, and ancillary-services to grid operators and wholesale markets. The modern utility will enable the integration of distributed energy resources and the optimization of loads by sending efficient market signals and incentives, giving distribution system users an active role in operation and optimization of the power system. Finally, the collection and provision of data generated by new grid monitoring and communications capabilities and advanced metering equipment may become a central part of the utility business model. As utilities explore new business models, they should demonstrate how they plan to add and capture value through the provision of information and data while securing the privacy of network users.[15]

As the utility's business model evolves, policy makers and regulators will have to address important questions about the roles and responsibilities of the regulated utility. How will a basic level of electricity services to which all users are entitled be defined? How will utilities be compensated for providing new, enhanced or differentiated services, such as improved reliability, to specific customers who are willing to pay more for higher-performance? And what activities are the domain of the regulated utility versus their unregulated subsidiaries or sister companies, who will likely become active participants in competitive distributed energy markets?

The Distribution Utility: Lifeblood of the Modern Grid

Electricity distribution utilities will be at the heart of the 21st century electricity system, taking on central roles as distributed system platform operators, integrators of distributed energy resources and smart loads, and providers of valuable electricity services. Modern utilities will provide incentives for distributed energy resource owners and empowered consumers to optimize their electricity consumption and production, contract with, and enable third parties and competitive suppliers to invest alongside them to expand network functionality and support efficient grid operations, and even operate new markets for the supply of grid services from distributed energy resources and smart loads. In short, distribution utilities will build and operate the essential platform network of the modern grid. Along the way, utilities can take advantage of new opportunities to increase financial returns by optimizing costs, improving grid performance, and enabling a rich and growing range of distributed electricity services and markets.

A business case approach to utility planning should be adopted

In evaluating utility business plans, regulators should require utilities to adopt a business case approach to benefit-cost analysis to ensure that the value delivered by grid modernization efforts justifies the costs of those investments. Benefits should be considered across a wide range of performance priorities, including: affordability, reliability, resilience, environmental performance, information access, customer engagement, return on innovation, and beyond. Given the rapidly evolving nature of the power system, this business case approach should also include consideration of risk, uncertainty, and option-value in addition to direct benefits and costs. Utilities should embrace and articulate this "value for money" approach. Part of moving from a commodity delivery-based business to a service-based business is clearly showing the quality and value of services provided and the third-party services and market activity enabled by the distribution system and demonstrating how investment plans will improve performance to deliver valued outcomes.

Retailers, Services Providers, and Aggregators: Flourishing in a Modern Grid

Competitive electricity retailers, energy service providers, and aggregators of distributed energy resources and smarter loads will flourish in a 21st century electricity system. Retailers can offer innovative, differentiated supply products that provide varying degrees of exposure to or hedging against time varying rates in response to diverse end-user preferences. Competitive energy service companies can offer bundles of distributed energy resources, storage, energy efficiency, and IT-enabled energy management systems to meet end-use energy needs. Meanwhile, aggregators can bundle and manage large numbers of distributed resources and loads to achieve economies of scale and scope and offer services to grid operators.

The Cost Recovery Challenge: A New, Forward-Looking, Outcomes-based Regulatory Framework

Seizing the grid modernization opportunity requires a regulatory framework that is forward-looking and focused on outcomes and results. This will entail a departure from the traditional approach to utility regulation but is a necessary step to enable a new utility business model and continuously modernize the grid.

Traditional cost-of-service regulation is an historically-focused approach[16] based on reviewing the prudency of a utility's inputs (i.e., investments and expenditures) to ensure that utilities are not charging unreasonable rates and to set fair utility returns on investment. This approach worked reasonably well to encourage prudent utility behavior and provided just and reasonable rates for customers when utility investments were relatively large, discrete, and similar to previous investments (as in the case for transmission assets or generation investments prior to restructuring) and when electricity sales were growing robustly. This traditional regulatory framework is not adequate, however, to support the number, variety, and changing nature of investments in a modern distribution grid, spur technology and business model innovations, or enable new distributed services and markets, particularly when electricity sales are flat or declining. Moreover, a traditional cost-of-service regulatory process provides weak incentives for utilities to capture cost-saving opportunities. Its focus on inputs makes it difficult to provide incentives for utilities to deliver or enable the full range of outcomes demanded by network users. In addition, traditional regulation may be inadequate to support necessary investments in grid repair and modernization and can undermine incentives to adopt advanced energy technologies and novel grid operation practices.

With its focus on reviewing costs to provide service, the traditional regulatory approach requires examining the prudency of expenditures associated with thousands of individual distribution system assets. This task poses an expensive challenge for regulatory commissions with limited staff and resources and exacerbates information asymmetries that exist between regulators and utilities. Regulators thus routinely lack the information necessary to assess whether a utility has taken full advantage of all opportunities to cut costs and improve performance. At the same time, utilities have little financial incentive to capture cost-saving opportunities, as they only profit from these savings until the next rate case, when regulators will reset rates to align with the cost of providing service. Utilities are thus encouraged to focus primarily on short-term cost savings, sacrificing the opportunities that could be unlocked if utilities invested with a longer-term view.[17]

This focus on the reasonableness or prudency of *inputs* also makes it challenging for utilities to respond to evolving consumer demands for *outcomes* and deliver improved performance, such as enhanced resiliency or access for distributed resources to sell services to system operators or wholesale markets. Generally, the cost-of-service regulatory framework requires utilities meet minimum performance levels, but provides little incentive or reward for utilities that deliver a higher quality of service or new outcomes and services.

In addition, a traditional approach to regulation may be poorly suited to support the investments needed to upgrade and modernize the region's aging grid. Where regulation takes an historic view of utility expenditures (i.e., uses an historic test year), it introduces a delay between when a utility makes a new investment in the grid and when it begins to recover those costs through its next rate case. When electricity demand was growing robustly, as it did through much of the 20th century, this lag did not present a substantial challenge. Increasing sales covered (and sometimes exceeded) costs incurred since the last rate case. At a time of flagging growth or flat sales, however, this lag can result in a utility's inability to recover its prudently incurred costs to serve customers, creating a disincentive for needed network upgrades. This challenge can be addressed by frequent, annual rate cases, but at the cost of substantial regulatory burden and even further degradation of incentives for cost-saving efficiency.[18]

Finally, the after-the-fact review of utility expenditures can further undermine investments in grid modernization by introducing regulatory risk. In reviewing the prudency of utility investments, regulators typically rely on the incremental development of established best practices. This approach implicitly assumes the past is an appropriate guide for the future. As such, traditional regulation frequently requires utilities to justify novel investments and departures from established practices by proving that such changes will result in a net reduction in utility costs.[19] If a utility adopts a novel technology that fails to perform as expected, regulators may disallow cost recovery. As a result, utilities are often timid about adopting innovative technologies and practices and may instead go through a protracted cycle of internal testing and performance validation, regulatory approval for small-scale pilot projects, collection of data and assessment of pilot results, presentation of results to regulators, and finally, after many years, system-wide adoption of improved technologies or practices. This is hardly the picture of the dynamic, innovative distribution utility the Northeast needs to build and operate a modern, 21st century electricity system.

Grid modernization requires modernizing regulation

Regulators across the Northeast should pioneer a forward-looking, outcomes-focused approach to regulate distribution utilities. The past is no longer an accurate guide for the future, and a focus on reviewing inputs is not the way to ensure utilities are incentivized to deliver new outcomes and improved performance.[20] Forward-looking regulatory approaches include use of a future test year, multi-year revenue caps with profit/risk sharing, and capital trackers with efficiency incentives (i.e., CPI-X). Whatever approach is adopted, improving regulation involves three key steps.

First, regulators should work with the utility and stakeholders to define the set of outcomes the utility is expected to deliver in the years ahead. These outcomes and the investment plan to deliver them should be encompassed in the distribution utility's forward-looking business and system plans discussed above. Regulators should then set distribution company revenues to support investments that deliver desired outcomes while incentivizing cost-saving system-wide efficiency. Massachusetts and New York have already initiated proceedings to begin defining these key outcomes, among other things,[21] and other states across the region will soon start this process as well.

Second, mechanisms should be employed to ensure that both utilities and ratepayers benefit from cost-saving efficiencies. For example, a forward-looking, multi-year revenue cap allows utilities to earn more by capturing system-wide efficiencies and reducing costs below the revenue cap. At the beginning and end of each regulatory period, regulators would review the utility's cost of service and reset allowed revenues to transfer achieved cost savings to ratepayers. In addition, sharing mechanisms can be employed to ensure profits and risks are apportioned appropriately between utility shareholders and ratepayers in between these reviews.[22]

Third, regulators should define outcome-based incentives that reward utilities for delivering value to, and enabling value creation by network users, including reducing system losses, enhancing resilience and reliability, improving environmental performance, facilitating new markets, integrating distributed energy resources, and excelling in other aspects of the utility's new roles and responsibilities.[23] These outcome-focused incentives are important to encourage the transformation of the utility business model from a focus on the commodity delivery of kilowatt-hours to a focus on building a distribution platform that can deliver the range of product and service outcomes desired by customers and policymakers as well as new innovations brought to market by third parties. Such a regulatory framework would support investments in a modern grid with enhanced reliability, resiliency, and environmental performance. It would also align incentives to fully integrate distributed energy resources, encouraging utilities to view distributed energy resources' owners as both customers and system users with unique needs to be served and new partners in efficient operation of system. Outcome-based incentives are also critical whenever regulators employ financial incentives for cost savings. Without these outcome-based incentives, utilities may be incentivized to pursue cost reductions that come at the expense of degraded system performance or reliability (i.e., by reducing maintenance expenditures or deferring important system upgrades). The combination of cost-saving incentives and outcome-based rewards can thus ensure utilities optimize expenditures to deliver desired outputs at the least cost.

There are several precedents and helpful models for this kind of forward-looking, outcomes-based approach (see box on page 12) upon which policy makers and regulators in the Northeast can build a 21st century regulatory framework. The region's successful experience harnessing energy efficiency also provides a guide to the rich rewards when regulatory innovation aligns incentives between utilities, energy consumers, and third parties to unlock innovation. The Northeast's experience with electric industry restructuring is another prime example.

The Rate Design Challenge: Efficient and Fair Tariffs for a Modern Grid

Hand-in-hand with improving methods for establishing a utility's allowed revenues, regulators must also develop improved electricity tariffs or rates that set fair prices for the range of services distribution utilities deliver and ensure recovery of allowed costs, compensate distributed energy resources and electricity users for the services they provide, and send market signals to network users to optimize system-wide efficiency. Tensions created by misalignments between the drivers of utility costs and the way these costs are charged to utility customers can already be seen in the growing debate over net metering policies for solar and other distributed generators. While net metering is a salient example of the issues at stake, the motivations for improved rate design for a 21st century electricity system are actually much broader.

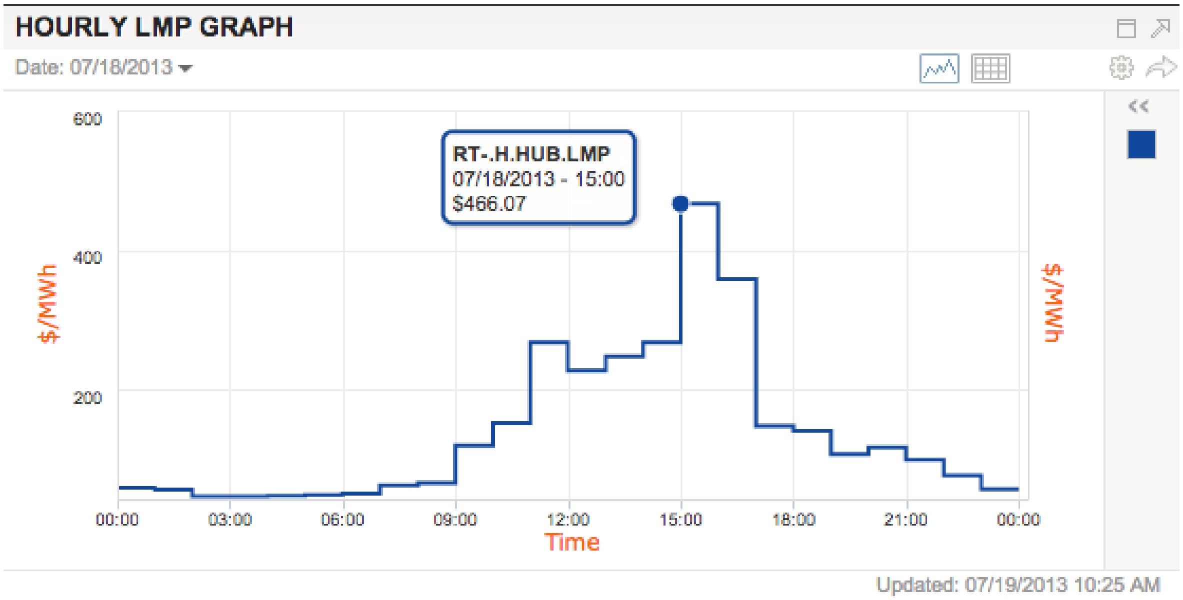
Today, most of the utility's costs are recovered through flat, volumetric, per-kilowatt-hour rates that bundle together the fixed costs of grid assets, the costs of operating the grid at desired performance levels, and the commodity costs of supplying electricity.[25] This practice derived in part from the limited functionality of conventional electricity meters, the previous generation's analog or manual controls of electricity networks and distributed devices, and the inability to convey more accurate price signals to network users and equip them with the technologies that enable more responsive loads. Today, new technology, including advanced metering infrastructure and information and communications capabilities, are quickly removing these limitations. Widespread adoption of these modern technologies can thus enable the development of new and improved rates.

There are two key challenges associated with conventional flat, volumetric electricity rates. First, flat rates signal to utility customers that using or producing electricity at any time of the day

Outcome-focused Regulation for the Modern Grid: Lessons from the UK

Regulators and utilities in the United Kingdom face many of the same challenges as in the Northeast, including an aging grid, a growing role for variable renewable energy generators, and increasing penetration of distributed energy resources. After an extensive process of stakeholder dialog, the UK's Office of Gas and Electricity Markets recently adopted a comprehensive, outcome-focused regulatory framework for electricity and gas transmission and distribution utilities known as "RIIO" (for "Revenue set to deliver strong Incentives, Innovation and Outputs"). RIIO provides clear incentives for utilities to improve performance, optimize costs, and drive innovation. Key features include submission of detailed, forward-looking utility business plans, a multi-year revenue cap with a risk/profit sharing mechanism, and clearly defined outcome-focused metrics with performance incentives rewarding improvements in system reliability, losses, environmental impacts, customer satisfaction, and other desired outcomes.[24]

Figure 2. Hourly wholesale electricity market prices for New England on July 18th, 2013, the 9th highest peak-demand day ever recorded[26]



or year has the same cost. Yet the cost of generating and delivering electricity varies from hour to hour and season to season, as demand rises and falls and more or less costly generators are turned on to supply electricity. On a typical day, the cost of supplying electricity in the afternoon is regularly three to five times higher than supplying electricity at night, while electricity prices can rise by a factor of 10 or more on peak summer days when the power system is under stress. As a result, electricity users over-consume during expensive periods of peak demand and under-consume during off-peak hours. These inefficiencies cost all electricity users more.

In addition, while all electricity users pay the same cost per kilowatt-hour under flat tariffs, not all users contribute equally to the costs of building and operating grid assets. The result is that users who contribute most to system-wide peaks in demand are cross-subsidized by other users with relatively flat load profiles who consume more of their energy in off-peak periods. Contrary to perceptions, as research from The Brattle Group finds, there is no reason to believe that low income customers are on the receiving end of these implicit cross-subsidies today. In fact, the opposite seems to be the case, with the vast majority of low-income network users standing to benefit from time varying rates leading to a fairer allocation of network costs.[27]

Second, particularly at a time of flat or declining energy usage, volumetric rates that recover the costs of the distribution network on a per-kilowatt-hour basis exacerbate the challenge utilities face in recovering their costs to maintain and modernize the distribution grid, especially when a large portion of those cost are driven by the maximum level of customer demand, rather than the total volume of electricity delivered.[28] Volumetric rates mean utilities recover system costs based on how many total kilowatt-hours a network user consumes, rather than how much that user contributes to cost drivers such as the system-wide peak. This mismatch between what drives the cost of delivering electricity and the way users pay for these services can lead to a growing disconnect between collected revenues and the investments necessary for utilities to maintain and modernize the grid. If energy efficiency or distributed energy resources lead to a decline in total kilowatt-hours sold but do not reduce peaks in demand, utility costs may grow while their revenue falls. Utilities will have no choice but to raise electricity rates for everyone as a result.

To facilitate grid modernization, rate design should be modernized as well

Regulators should update and improve electricity rate design to accomplish three objectives simultaneously. First, rates should send accurate signals about the value of consuming or producing electricity at different times and locations and under different system conditions, enabling customers to optimize their use of the electricity system. Second, rates should ensure utilities have a reasonable opportunity to recover all allowed costs in a fair and non-discriminatory manner. Finally, rates should be designed to further regional policy objectives, such as incentivizing energy efficiency or distributed energy adoption. However, accomplishing these three objectives may require balancing among them. Policy goals must be carefully considered and rates should be designed in a way that preserves efficient price signals and maintains adequate cost recovery.

To accomplish these three objectives, regulators should explore new ways of pricing distribution services, including time varying rates, a blend of volumetric, peak demand-based, and fixed charges, and other innovative pricing mechanisms. Changes in how rates are designed will be critical both to enable distribution utilities to move beyond the commodity delivery of kilowatt-hours and embrace their role as distribution system platform operators and to ensure network users receive fair and accurate price signals and are compensated for optimizing their consumption and production of electricity services.

For example, time varying rates for electricity supply would link wholesale and retail electricity markets, enabling more efficient behavior, fairly pricing the production or consumption of electricity during peak and off-peak periods, and avoiding cross-subsidization among network users.[29] Time varying rates can help users optimize their electricity consumption, reducing demand for the most costly peak generators and helping avoid unnecessary new grid expansion. That means that even electricity users who have important demands for electricity during peak hours and do not adjust their consumption under time varying rates stand to gain, as wholesale electricity prices and grid costs will be lower. Once advanced metering infrastructure is widely adopted, regulators across the region can move customers to time varying rates, starting with users best able to respond to these economic signals.[30]

In addition, as a large portion of the costs of building and operating the distribution system are fixed and driven by users' maximum electricity demand rather than total kilowatt-hours of consumption, regulators should explore designs for the portion of rates that pay for the delivery of electricity that blend volumetric, peak demand-based, and fixed charges.[31] These blended rates could help address the revenue adequacy challenge while more accurately reflecting different users' contributions to grid costs and providing strong incentives for energy efficiency and customer-sited distributed energy resources that deliver the greatest system-wide cost savings.[32]

Whatever approach is chosen, regulators should move towards rate designs that more closely align the nature of the costs incurred by users of the electricity system with the way electricity rates are collected. Improved rates should ensure that electricity users both pay their fair share for distribution services *and* are fairly compensated for reducing system costs or providing system services (i.e., by optimizing demand or production from distributed energy resources). The result would enable electricity users to capture the value of services they provide to the grid, ensure more efficient utilization of electricity system assets, and reduce costs for all electricity users. Electric utilities today have average asset utilization rates below 50 percent, a far cry from other capital-intensive industries, which are often 75 percent or greater.[33] By reducing peak demands, optimizing consumption to better utilize assets, and sending price signals for distributed energy resources to help reduce congestion and losses and supply electricity when needed most, improved tariffs can result in substantial cost savings, which translates into less money spent on electricity and a more competitive economy across the Northeast.

Empowered Customers in a Modern Grid

Electricity customers and network users will be more engaged and empowered than ever in a modern grid. No longer simply passive consumers of electricity, customers of the 21st century electricity system will increasingly generate and store their own electricity with distributed energy resources and even offer grid services to utilities or third-party aggregators. Customers will be empowered to optimize their energy consumption and generation in response to new, dynamic rates. And they will benefit from a much wider range of differentiated electricity services, products, and technology options while enjoying tangible improvements in grid reliability, cost, and performance.

Unlocking Innovation: Transforming Utilities into System Integrators of Advanced Energy Technologies

To become the central platform of a 21st century electricity system, distribution utilities across the Northeast must continually evolve to adapt to new technologies and changing energy needs across the region. To excel in this new role, utilities should become active partners with the region's advanced energy companies and innovative system integrators of new energy technologies.

Today, U.S. electric utilities spend as little as 0.2 percent of their revenues on R&D on average, far below the 2 percent average across all U.S. industries and two orders of magnitude less than some of the most innovative sectors of the economy.[34] These long-term investments in new technology fall outside the traditional responsibilities of regulated utilities. At the same time, the current regulatory framework makes it difficult for utilities to demonstrate and adopt emerging technologies offered by advanced energy companies.

While a forward-looking regulatory framework, such as that described above, will encourage utilities to seek cost-saving innovations with near-term payoffs, these incentives may still be insufficient to encourage long-term innovation efforts that have less certain payoffs and may take multiple years to develop. As a result, electricity users across the region may experience higher costs and lower service quality over the long-term than they would if utilities embraced more innovation.

While electric utilities are unlikely to be the primary actors engaged in energy research and development, policymakers and regulators across the region should consider the value of more active utility engagement in innovation and provide mechanisms and incentives to encourage such activities. In particular, regulators should allow utilities to establish and increase internal budgets for demonstration, testing, integration, and accelerated learning about the performance, cost, and capabilities of new technologies. These innovation activities would be consistent with the modern utility's role as an active system operator and integrator of distributed and advanced energy technologies and would ensure that the Northeast's utilities will be positioned to take advantage of cutting edge technologies and capabilities.

To capture and share the lessons learned from demonstrations, policymakers should consider pooling some innovation funds regionally to be awarded competitively to the best proposals from utilities, third parties, and partnerships between them.[35] The result would be enhanced competition for innovation proposals and an accelerated dissemination of new ideas, technologies, and practices across the region. Everyone can benefit from the experience and learning generated by research and demonstration projects. These innovation efforts should therefore be encouraged and supported at the regional level, with the broad knowledge harnessed for the benefits of electricity users across the Northeast.

Spurring Network Innovation for a Modern Grid

To drive innovation and ensure utilities stay at the cutting-edge of new technology capabilities, regulators in the UK made available up to £500 million ($837 million) over the 2010-2014 regulatory period to pilot larger-scale, innovative demonstration projects, launch smaller technical, commercial, or operational projects directly related to a utility's system, and roll-out proven modern solutions. The majority of funds are awarded annually through a competitive process to the best large-scale projects trialing new technologies and operating and commercial arrangements. Electric distribution utilities, third-party advanced energy companies, and partnerships thereof are all eligible to apply for funding, and to ensure lessons learned are widely shared, all winning projects must submit regular updates at a public online portal.[36] Discretionary awards are also offered to reward projects that help power grids adapt to climate change while providing security of supply and value to customers. This successful program is being continued as the annual Electricity Network Innovation Competition under the new RIIO framework (see box on page 12) and the competitive awards will be supplemented by a Network Innovation Allowance, which allows each distribution utility to invest up to 0.5 percent of their revenues in network innovation projects.[37]

Similar innovation funding programs in the Northeast include the New York State Research and Development Authority (NYSERDA) and the Massachusetts Clean Energy Center (MassCEC), both of which are funded primarily by a system-benefit charge paid by electricity customers and award funding to innovative research and demonstration initiatives and advanced energy companies.[38] Both programs provide fertile ground for larger, region-wide initiatives to spur network innovation and grid modernization.

Seizing the Grid Modernization Opportunity

The challenges arising from the rapid evolution of electricity system needs and technologies are by no mean unique to the Northeast. But by acting with bold initiative and leading the regulatory and policy innovations necessary to seize the grid modernization opportunity, the Northeast can position itself at the forefront of a new era of electricity innovation. A modern, 21st century electricity system can deliver real economic, energy, and environmental benefits for the region by enabling a more efficient, flexible and resilient grid that gets cleaner year after year.

The economic rewards from grid modernization can be substantial, and a 21st century regulatory framework and modern electricity tariffs can unlock real cost savings for the entire region. Adoption of a forward-looking regulatory framework for transmission and distribution utilities in the UK resulted in a 9 percent savings for retail electricity customers, according to an analysis for the World Bank.[39] Those savings were on par with reductions in rates due to wholesale market competition introduced in the UK at the same period. Shifting to time varying rates could also result in further cost savings for 60 percent of residential electricity customers and 80 percent of low-income households[40] by helping those customers better optimize their consumption. When introduced at scale and coupled with smart technologies in the home or business, time varying rates may help reduce electricity demand during critical peak periods by more than 20 percent,[41] reducing the need for the most costly power plants and avoiding transmission and distribution investments. Considering the need for substantial new investments in grid modernization, these cost savings will be critical to ensure electricity rates remain affordable for all consumers by reducing wholesale market prices and more efficiently utilizing grid assets.

A more efficient, modern grid will thus position the Northeast to better compete in the global economy. States and regions today are competing with their counterparts worldwide to be the most attractive place for businesses to locate, and the cost and reliability of power are key factors in those decisions. At the same time, leading the effort to unlock more competitive electricity markets, spur innovation and adoption of advanced energy technologies, and create a modern grid can support the growth of the Northeast's vibrant advanced energy economy.

Smart regulation can also accelerate the transition to a modern grid that is more energy secure and better able to withstand extreme weather and other stresses, and recover more quickly from outages. Without updating and modernizing the nation's aging grid, the American Society of Civil Engineers estimates that economic costs associated with power outages could rise to nearly half a trillion dollars by 2020.[42] In contrast, the widespread deployment of grid monitoring and control capabilities will help utilities more rapidly identify and isolate faults, restore outages, and reroute power to minimize the impact of power failures. Initial demonstrations of 'self-healing' distribution feeders funded by the Department of Energy have cut the frequency of power outages by 11 to 49 percent and reduced the duration of remaining interruptions by up to 56 percent.

By integrating distributed energy resources into power system operations, utilities may reduce the impact of outages even further. When Hurricane Sandy caused widespread electricity disruptions across the region in 2012, a few islands of power remained, supported by co-generation and microgrid systems at a few locations, including New York University's Manhattan campus.[43] Yet today, most distributed energy resources connected to the grid automatically shut off when power from the grid fails. Utilities have traditionally had no choice but to require this practice. With very little visibility over distributed generators, automatic disconnection is necessary to protect line workers trying to restore power. A modern grid with advanced communications and monitoring capabilities could better utilize these distributed resources to keep homes and businesses powered when the high-voltage grid fails.

Finally, grid modernization will be a critical enabler of major policy priorities across the region, including state and regional environmental priorities. Improved regulation and rates will be important drivers of energy efficiency, while a 21st century grid is essential to better integrate and accelerate growth of renewable energy in the region's electricity system. A more resilient power grid will help the region adapt to a changing climate. And by facilitating the adoption of distributed energy resources, including solar panels, electric vehicles and charging infrastructure, battery storage devices, smart devices and buildings, and other new technologies and services, grid modernization can help meet state, regional, and federal greenhouse gas reduction goals.[44]

The time is now to seize the grid modernization opportunity in the Northeast. This region has a history of leading important reforms and smart policies that unlock cost savings and improve performance in the electricity sector. The Northeast showed the country how to get restructuring of wholesale markets right and has led on energy efficiency policy, renewable energy, and climate change. Now, the region has a chance to continue this legacy and build a 21st century electricity system that will position the region for economic competiveness, support the growth of our advanced energy economy, improve environmental performance, and deliver real cost savings for citizens across the Northeast.

Endnotes

1 “Failure to Act: The Economic Impact of Current Investment Trends in Electricity Infrastructure”, American Society of Civil Engineers, 2011.

2 New York Public Service Commission, “Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal,” Case 14-M-0101, April 24, 2014.

3 U.S. Energy Information Administration, “Retail sales of electricity to ultimate customers,” March 21, 2014.

4 See: Peter Kind, “Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business,” Edison Electric Institute, January 2013. See also: Peter Bronski et al., “The Economics of Grid Defection: When and Where Distributed Solar Generation Plus Storage Competes with Traditional Utility Service,” Rocky Mountain Institute, 2014.

5 “A Review of Electricity Industry Restructuring in New England,” Polestar Communications & Strategic Analysis, prepared for the New England Energy Alliance, September 2006.

6 Matthew Marmack, Edward Kahn and Susan Tierney, “A cost-benefit assessment of wholesale electricity restructuring and competition in New England,” *Journal of regulatory Economics* 31(2), April 2007. Susan Tierney and Edward Kahn, “A Cost-Benefit Analysis of the New York Independent System Operator: The Initial Years,” Analysis Group, March 2007.

7 Aggregators combine the operation of a number of distributed energy resources for which the ownership or geographic location is dispersed in order to achieve economies of scale and/or improve coordination of these dispersed assets. For example, an aggregator may combine the operation of dozens of individual electricity consumers to offer demand response resources to grid operators, or an aggregator may combine the operation of smart inverters for solar panels, electric car chargers or energy storage devices to provide voltage regulation or reactive power to distribution utilities.

8 A Distributed Energy System is a system combining one or more distributed energy resources (including distributed generation, distributed storage, and/or demand response) with information and communication technologies to enable a business model that provides valued services to energy end users or upstream electricity market actors. Examples include microgrids, home energy systems that optimize operation of smart loads, PV panels and energy storage devices, or networked smart charging of electric vehicles. See Ashwini Bharatkumar et al., “The MIT Utility of the Future Study: Preliminary Report,” Massachusetts Institute of Technology, 2014 (Forthcoming).

9 Dwight Einhorn, “Bank of America Downgrades Pinnacle West Capital on Difficult Regulatory Cycle Ahead” *Yahoo Finance*, March 28, 2014, ; Michael Aneiro, “Barclays Downgrades Electric Utility Bonds, Sees Viable Solar Competition,” *Barrons.com*, May 23, 2014.

10 Stephen Lacey, “Wall Street Firms Step Up Warnings About Distributed Energy’s Threat to Utilities,” *GreentechMedia.com*, May 27, 2014.

11 Massachusetts and New York have already taken important steps towards establishing this shared vision through recent proceedings. See "Reforming the Energy Vision," New York Public Service Commission, Case 14-M-0101, and "Grid Modernization," Massachusetts Department of Public Utilities, Proceeding 12-76.

12 R. Singh and B. Vyakaranam, "Evaluation of Representative Smart Grid Investment Grant Project Technologies: Distributed Generation," U.S. Department of Energy, February 2012. Results are for solar PV penetration of 2-6 percent of peak load on various distribution feeders. Higher penetration levels without any compensating technologies or improperly sized PV generation reduce benefits or even lead to increases in losses, highlighting the importance of incentivizing optimal siting of PV systems.

13 "Application of Automated Controls for Voltage and Reactive Power Management: Initial Results," U.S. Department of Energy, December 2012, https://www.smartgrid.gov/sites/default/files/doc/files/VVO%20Report%20-%20Final.pdf

14 "Borrego Springs Microgrid Keeps Electricity Flowing to Customers During Recent Outage," San Diego Gas and Electric, November 10, 2013. "San Diego Gas and Electric (SDGE) Borrego Springs MicroGrid," U.S. Department of Energy, September 2013.

15 Data services may become an important new area of value creation and revenue growth of the 21st century distribution utility but raise a set of important, unresolved questions about privacy, data access for non-utility market actors, and appropriate revenue models. States need not start from scratch and should look to national industry standards for guidance on these key issues, such as the National Institute of Standards and Technology's Interagency Report (NISTIR) 7628, "Guidelines for Smart Grid Cyber Security." see New England Clean Energy Council Initial Comments on DPU 12-76-A, January 17, 2014, at 16-17. See also: New York Public Service Commission, April 2014, *op cit.*

16 Note that some states adopt a future test-year for cost-of-service regulation, which is a step towards a more forward-looking regulatory framework, as discussed later in this section.

17 For further discussion of cost-of-service regulation, see David Malkin and Paul A. Centolella, "Results-Based Regulation: A Modern Approach to Modernize the Grid," GE Digital Energy and Analysis Group, 2013.

18 As discussed above, the lag between rate cases introduces an incentive for utilities to capture short-term cost savings because the utility retains any firm-wide savings achieved between rate cases. However, these incentives are weak and this regulatory lag can lead to an underinvestment in needed network assets. In addition, if rate cases are performed annually, incentives for utilities to pursue cost-saving are all but eliminated. Other regulatory mechanisms can provide much better incentives for cost-saving efficiencies, as discussed later in this section. See Paul L. Joskow, "Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks," in Nancy L. Rose (Ed.), *Economic Regulation and Its Reform: What Have We Learned* (Forthcoming), University of Chicago Press. See more at: http://www.nber.org/chapters/c12566

19 See Malkin and Centolella, 2013, *op cit.*

20 Some regulators hold the view that future test years expose ratepayers to "unwarranted risk" (See Massachusetts Department of Public Utilities, Proceeding 12-76, Order 12-76-B at 21.) As the New England Clean Energy Council and others commented in this proceeding on January 17, 2014, "Commissions across the country have a long and successful history with using Future Test Years (FTYs). Since the New York Public Service Commission allowed the first use of a partial FTY in 1972, the use of FTYs has grown and now a majority of state commissions have used either full or partial FTYs in rate cases, and several exclusively use future test years. In total, 14 state commissions and the Federal Energy Regulatory Commission regularly use FTYs, 14 commissions rely on future test years to varying degrees, and three commissions employ a partially-forecasted test year method. Only 20 states, including Massachusetts, rely solely on historical test years." Moreover, Massachusetts itself has had great success with regulatory policy that has "deviated from traditional, after the fact recovery of electric distribution company investment." (See New England Clean Energy Council Initial Comments on DPU 12-76-A, January 17, 2014, at 16-17.)

21 See New York Public Service Commission, Case 14-M-0101 and Massachusetts Department of Public Utilities, Proceeding 12-76, *op cit.*

22 For a step-by-step approach to adopting a multi-year revenue cap with profit/risk-sharing and annual *ex post* adjustments to account for realized network use and expenditures, see Jesse Jenkins, "Economic Regulation of Electricity Distribution Utilities Under High Penetrations of Distributed Energy Resources," Massachusetts Institute of Technology, June 2014, http://bit.ly/JDJenkinsThesis. See also: "Handbook for implementing the RIIO model," U.K. Office of Gas and Electricity Markets, October 2010, https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbook.pdf.

23 For discussion of outcome-focused incentives, see: "RIIO: A new way to regulate energy networks," UK Office of Gas and Electricity Markets, October 2010; and Malkin and Centolella, 2013, *op cit.*

24 See "Network Regulation, the RIIO Model," UK Office of Gas and Electricity Markets, , and UK Office of Gas and Electricity Markets, 2010a, 2010b, *op cit.*

25 Large commercial and industrial customers today often have more complex rate structures that reflect the recovery of fixed costs, the customer's contributions to peak system capacity and power quality needs, and the variable costs of delivering electricity. These rates are the exception rather than the rule for most network users today, and can be a guide for a more cost-reflective and fair allocation of network costs to all users.

26 Source: ISO-New England

27 Ahmad Faruqui and Neil Lessem, "Comments on Massachusetts Department of Utilities Notice DPU 14-04: Investigation by the Department of Public Utilities upon its own motion into Time Varying Rates." Prepared for the NECEC Institute, March 10, 2014.

28 For example, the utility has to build a distribution system that can meet the aggregate peak demand of all network users. Once those grid investments are made, the costs are largely fixed. Likewise, the grid connection built to give a network user access to the system must be large enough to accommodate the user's maximum contracted demand or production level, irrespective of what portion of that maximum connection capacity they use on a regular basis. See Maria Pia Rodriguez Ortega et al., "Distribution network tariffs: A closed question?" *Energy Policy* 36 (2008): 1712-1725.

29 The wholesale price of electricity as delivered to the primary distribution substation is the most obvious price signal to pass through to electricity users via time varying rates, but going forward, the time and location-varying costs of delivering electricity across distribution networks could also be included (i.e., distribution-level locational marginal pricing).

30 One way to accomplish this transition would be to require that default tariffs for energy supply be time varying. Competitive retailers could then offer a range of alternative rate products that hedge risks in various ways to match the diverse preferences of various network users. Utilities and regulators will also need to develop common information standards and rules for data transparency and customer access to pricing and information about their energy consumption profiles in order to enable a responsive role for grid users and facilitate the development of new third party products and services to manage electricity consumption and production. See Faruqui and Lessem, 2014 *op cit.* for more.

31 For example, use of network tariffs could include three components: (1) a fixed connection charge reflecting the assets needed to connect the user to the grid and give them access to electricity markets; (2) a peak demand-based charge updated periodically to reflect a user's contribution to the aggregate system-wide peaks that the grid must be built to accommodate; and (3) a volumetric charge to reflect a user's contributions to incremental wear-and-tear on the network and distribution system losses, both of which are more a function of total kilowatt-hours consumed. See Maria Pia Rodriguez Ortega et al. 2008, *op cit.* for more.

32 Under blended tariffs, the peak demand-based portion of the charge, in conjunction with time varying rates for energy supply, incentivizes network users to reduce their peak use of the transmission and distribution system, saving on costly network upgrades and reducing the need for the most expensive and often dirtiest peak power plants. At the same time, the volumetric portion of the blended use of network tariff along with a volumetric, time varying rate for electricity supply will maintain strong incentives to reduce overall electricity demand.

33 Malkin and Centolella, 2013, *op cit.*

34 Malkin and Centolella, 2013, *op cit.* and Norm Augustine et al., "A Business Plan for America's Energy Future," American Energy Innovation Council, 2010.

35 Pooled utility innovation funding has precedent in the Electric Power Research Institute. However, with restructured regional markets, the 21st century version of this leveraged effort would be regional in scope and include demonstration of both technologies and new operational models and practices, including innovative rate designs, information platforms, and novel partnerships between utilities and third parties.

36 See: "Smarter Networks Portal," Energy Networks Association.

37 "Electricity Network Innovation Competition," UK Office of Gas and Electricity Markets. "Provisional Network Innovation Allowance for Distribution Network Operators," UK Office of Gas and Electricity Markets, February, 2014.

38 See http://www.nyserda.ny.gov/ and http://www.masscec.com/

39 Stephen Littlechild, "Privatization, Competition, and Regulation in the British Electricity Industry, With Implications for Developing Countries," Energy Sector Management Assistance Program (ESMAP), World Bank, February 2000. See also Tooraj Jamasb and Michael Pollitt, "Incentive regulation of electricity distribution networks: Lessons of experience from Britain," *Energy Policy* 35 (2007): 6163-6187.

40 Faruqui and Lessem, 2014, *op cit.*

41 Malkin and Centolella, 2013, *op cit.*

42 American Society of Civil Engineers, 2011, *op cit.*

43 Jeff St. John, "How Microgrids Helped Weather Hurricane Sandy," *GreentechMedia.com*, November 20, 2012.

44 For example, under proposed EPA regulations for carbon dioxide emissions from existing power plants, states will have considerable flexibility to adopt a wide range of solutions from across the electricity system. A modern grid will help unlock a wider range of creative and cost-effective means to comply with such regulations across the region, including greater adoption of energy efficiency and low-carbon distributed energy resources. For more on EPA regulations, see at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

CERTIFICATION

I hereby certify that on October 23, 2015, I sent a copy of the within to all parties set forth on the attached Service List by electronic mail and copies to Luly Massaro, Commission Clerk, by electronic mail and regular mail.

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