THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

IR 15-296

ELECTRIC DISTRIBUTION UTILITIES

Investigation into Grid Modernization

Order on Scope and Process

O R D E R N O. 25,877

April 1, 2016

I. Introduction

On July 8, 2015, the Governor signed House Bill 614, implementing goals of the State 10-year energy strategy developed by the New Hampshire Office of Energy and Planning. One element of that bill required the Commission to open a docket on electric grid modernization.

On July 13, 2015, the Commission opened this docket to investigate grid modernization in New Hampshire. The Order of Notice invited comments by September 17 regarding "the definition, or elements, of grid modernization that should be included in this investigation."[1]

The Commission received comments from all the electric utilities, the Office of Energy and Planning, the New Hampshire Office of the Consumer Advocate, and a variety of other interested parties. All of the comments are available on the Commission website at: https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296.html. The Commission appreciates the thoughtful comments provided by these parties.

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[1] IR 15-296 Order of Notice at 2.

With this order the Commission is establishing a formal process to obtain additional input from interested parties, to create an open dialog on key grid modernization topics, and to reach as much agreement as possible on regulatory opportunities for advancing grid modernization in New Hampshire. This order also identifies the key goals of grid modernization and defines the topics of inquiry the Commission expects to be most pertinent in this process.

The Commission's responsibility is to ensure that the electric utilities provide safe, reliable electricity services at just and reasonable rates. Grid modernization policies, technologies, and practices should help fulfill this responsibility by enabling electric utilities to take advantage of new and emerging technological developments, providing customers with new service offerings, and helping customers optimize their electricity consumption patterns. The Commission believes that grid modernization can spur the development of cost-effective distributed energy resources, including energy efficiency, demand response, distributed generation, storage technologies, and more. The Commission expects the benefits of grid modernization will include the following:

- Improving the reliability, resiliency, and operational efficiency of the grid.
- Reducing generation, transmission, and distribution costs.
- Empowering customers to use electricity more efficiently and to lower their electricity bills.
- Facilitating the integration of distributed energy resources.

One of the Commission's goals in this investigation is to ensure that grid modernization results in net benefits for customers. This means (1) that the overall benefits of grid modernization initiatives must exceed the overall costs, (2) that all customers must have a meaningful opportunity to enjoy grid modernization benefits, and (3) that the costs of grid modernization are allocated fairly among all customers. The Commission directs the Working Group, described in Section III below, to consider this goal of net customer benefits throughout the process.

II. Topics of Inquiry

One of the challenges of discussing grid modernization is that it covers several different aspects of the electric utility system and many types of technologies with different capabilities that can result in a variety of different outcomes. Different grid modernization technologies are frequently characterized as being either "customer-facing" or "grid-facing."

Customer-facing technologies and practices include measures that enable and encourage customers to implement distributed energy resources, optimize their electricity consumption, and reduce their electricity bills, using for example: two-way communication systems; enhanced customer information delivery systems; in-home energy devices; programmable, communicating thermostats; and smart, communicating appliances.

Grid-facing technologies and practices allow utilities to optimize the delivery of electricity to homes and businesses by, for example: detecting, isolating and restoring faults and outages; automatically reconfiguring feeders; implementing voltage stabilization technology; regulating voltage; remotely monitoring and diagnosing grid operations; and better integrating distributed generation technologies.

A. Distribution System Planning

Grid modernization technologies represent new resources that electric utilities can use to achieve safe, reliable, low-cost electricity services over the long-term. One of the challenges of grid modernization will be to identify and assess emerging technologies and practices, and select those that are most appropriate and in the public interest, on an on-going basis.

The Commission expects that grid modernization planning will build off of the electric utilities' existing practices for making investment decisions regarding the maintenance, operations and upgrades to their distribution systems. We also expect that grid modernization planning will fit naturally within the utilities' existing integrated resource planning (IRP) framework, which requires the utilities to file plans with the Commission for periodic review and approval. Those plans must assess a wide variety of resources, including demand-side resources, distributed generation resources, and "smart grid" technologies. *See* RSA 378:38-:39.

Grid modernization, however, raises some challenges that might warrant modifications to existing utility planning practices. The Commission expects the Working Group to address several questions regarding the role of grid modernization in the context of integrated resource planning. In particular:

- Do the current IRP requirements sufficiently define the scope of grid modernization capabilities and resources to be assessed in each plan, both in terms of grid-facing and customer-facing grid modernization technologies?
- How frequently should utilities be required to file their plans?

- Should the Commission review of the plans be modified in any way to account for grid modernization planning needs and challenges?
- Should the process for stakeholder participation in the planning process be modified in any way to account for grid modernization planning?
- How should cost-effectiveness be evaluated for grid modernization technologies and practices? Should cost-effectiveness account for (1) the geographic location of technologies and practices; and (2) the time-varying nature of generation, transmission, and distribution costs?
- How should the utility planning process account for the role of third-party vendors in providing grid modernization technologies and services, particularly customer-facing technologies and services?

B. Customer Engagement With Distributed Energy Resources

Although grid modernization offers the opportunity to significantly expand customer engagement with distributed energy resources, several challenges might need to be addressed to take full advantage of this opportunity.

1. Advanced Metering Functionality. The Commission seeks input on the role and the potential for advanced metering options to promote grid modernization, particularly customer engagement in distributed energy resources. In the Order of Notice for this docket, the Commission noted that, pursuant to RSA 374:62, "no electric utility is allowed to install a smart meter without the written consent of the customer." There appears to be some disagreement, however, about exactly what type of "smart meter" or particular functionality of a meter is covered by RSA 374:62, and therefore whether written consent of customers will be required for all types of

advanced meters or just particular capabilities of advanced meters (e.g., communication gateway between the meter and customer devices).[2]

The Commission directs the Working Group to investigate the opportunities for different types of advanced meters and advanced metering options to provide the functionality needed to support grid modernization. Table 1 presents a list of the advanced metering functionalities that would support grid modernization.

Table 1. Advanced Metering Functionality

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

The Commission directs the Working Group to consider the following questions with regard to advanced metering options:

- What options are there for achieving advanced metering functionality that will be legally and economically viable?
- If advanced metering infrastructure (AMI) specifically is not legally and/or economically viable, are there other technologies that can be used to enable customers to optimize their electricity consumption, adopt distributed energy resources, and reduce their electric bills? For example are there customer based

[2] New England Clean Energy Council, Comments filed in Docket IR 15-296 on October 5, 2015, at 1. Unitil Energy Systems, Comments filed in Docket IR 15-296, on September 17, 2015, at 9-10.

web enabled cost effective technologies that could assist customers in optimizing electricity consumption?

- Are there ways to "future proof" metering infrastructure to ensure long-term value of any investment in these technologies?

2. Rate Design. The Commission seeks input on the potential for rate design to promote customer engagement. We direct the Working Group to investigate the variety of different rate design opportunities available, such as time-varying rates (including time-of-use rates, critical peak pricing, real-time pricing, and peak-time rebates), fixed charges, minimum bills, demand charges, and declining or inclining block rates.

The Working Group should consider which of these rate design options could be made available in New Hampshire, given any limitations that might exist regarding the advanced metering options. Of those that are feasible, the Commission seeks a comparison of the advantages and disadvantages of different rate designs, in terms of which are likely to promote customer engagement and implementation of distributed energy resources, and minimize unreasonable cost-shifting among customers. Any new rate design proposals from the Working Group must meet the Commission's principles of efficiency, equity, simplicity, continuity, and revenue sufficiency.

We expect the Working Group to address questions regarding whether and how the electric utilities should offer time-varying rates through energy (default) service offerings, and the role that competitive electric power suppliers should play in offering customers time-varying rates for electricity, as well as any barriers that exist for the implementation of time-varying rate offerings through competitive electric power suppliers.

3. Customer Data. Access to detailed customer consumption data (including by time of day and location) may be extremely valuable in better enabling customer engagement in distributed energy opportunities. The Commission seeks input on how customer consumption data should be collected and shared with customers and whether and how it should be shared with third-party vendors of smart grid and distributed energy technologies. Specifically, what steps should the Commission take to:

- Ensure that utilities collect sufficient data.
- Ensure that utilities provide third-party vendors with open access to relevant customer data.
- Address privacy concerns regarding such customer data.

4. Customer Education. The Commission seeks input on the customer education activities that will be needed to support grid modernization activities and promote customer engagement. What type and level of enhanced customer education should the utilities and third-party providers make available to promote customer engagement and investment in both supply and demand options? How much will such enhanced customer engagement cost, and will the benefits exceed the costs?

C. Utility Cost Recovery and Financial Incentives

Grid modernization technologies and practices have prompted calls in other states for new ways of addressing utility cost recovery and financial incentives, with some stakeholders calling for new regulatory models to better fit the needs of the "utility of the future."[3] Central to these proposals is the premise that under traditional cost-of-service

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[3] See, for example, Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee, Final Report, July 2, 2013, pages 118-124.

regulation electric utilities are not provided with sufficient financial incentives to properly investigate and implement all potentially beneficial grid modernization technologies and practices. There are several key assumptions underlying this premise: (1) Utilities have a financial incentive to increase rate base, because increased rate base will result in increased allowed equity, earnings, and profits; (2) Utilities have a financial incentive to increase retail sales (as well as a disincentive to reduce sales), because retail rates are typically higher than marginal costs, which means that increased sales could result in increased earnings and profits; (3) Utilities have little financial incentive to reduce fuel or purchased power costs, because these costs are typically passed directly through to customers without any financial implications for the utility; (4) Some grid modernization technologies and practices are relatively new and innovative, which creates a risk that they will not perform as anticipated and regulators will not allow their costs to be included in rates in a subsequent rate case; (5) Lower sales growth in recent years, has resulted in the need for more frequent rate cases, which could reduce a utility's incentive to reduce costs and improve operational efficiency between rate cases.

The Commission seeks input on whether any changes to the current utility cost recovery and financial incentives are necessary to achieve the desired outcomes. For example:

- To what extent does the existing ratemaking paradigm in NH (with its implicit financial incentives) promote or inhibit the development of (a) grid-facing grid modernization, and (b) customer-facing grid modernization?
- What role, if any, should there be for pre-approval of grid modernization investments, either grid-facing or customer-facing?

- Is there a need for some form of performance-based regulation in New Hampshire to support grid modernization? If so, what form should it take? Should there be a required period between rate cases and if so, what should the period be? Should there be a revenue relief mechanism for load loss, and how should it be designed?
- Is there a need for performance incentive mechanisms in New Hampshire to support grid modernization? If so, what form should they take? What areas of performance should they apply to? What metrics should be used to measure those areas? What targets should the Commission set for those metrics? Should there be a system of financial rewards or penalties regarding those targets?
- Is a revenue decoupling mechanism needed to remove potential disincentives to utilities to invest in grid modernization investments?

III. Establishment of a Working Group

The Commission is initiating a formal Working Group process to obtain input from the distribution companies and other interested and knowledgeable organizations to assist the Commission with the development of appropriate regulatory policies to foster successful electricity grid modernization in New Hampshire.

The Commission has retained Raab Associates, Ltd. (Raab), to facilitate and mediate the Working Group process on behalf of the Commission. We have also retained Synapse Energy Economics to provide consulting services to the Commission staff and to assist the working group as needed.

The goal of the Working Group will be to develop recommendations to the Commission on the issues and questions outlined in this scoping order. These recommendations will be delivered to the Commission in a final report prepared by Raab with the assistance of Commission staff and its consultants as needed. The final report should embody any and all consensus recommendations. Where there is no consensus on a pertinent issue, two or more options should be provided along with the identities of the supporters of each option.

A. Background for Working Group

To facilitate stakeholder discussion, we believe it would be helpful to identify some possible outcomes and capabilities of grid modernization. For this purpose, we will take advantage of the work performed previously by the Massachusetts Electric Grid Modernization Stakeholder Working Group. Its report to the Massachusetts Department of Public Utilities includes a table that identifies the different outcomes that grid modernization might enable, the different capabilities or activities that might be needed to achieve those outcomes, and the different technologies that can be used to enable those capabilities or activities. That table is presented below as Table 2.

Table 2. Grid Modernization Outcomes, Capabilities, and Enablers.[4]

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

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

One of the first tasks for the Working Group will be to review the elements in Table 2, along with the illustrative listing of customer- and grid-facing technologies above, and to modify them as appropriate for the discussions in New Hampshire. This information will lay the foundation for the Working Group to identify the grid

[4] Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee, Final Report, July 2, 2013, at 12. Definitions and descriptions for these outcomes and capabilities are provided on pages 12-21 of the Massachusetts report.

modernization technologies and practices most relevant and appropriate for New Hampshire.

B. Working Group Process

We propose eight day-long Working Group meetings over the course of ten months to complete the Working Group process and then the delivery of a final report to the Commission. A preliminary schedule and work plan including dates for meetings in April, May, and June, as well as the timing and sequencing for addressing each category of issue during the Working Group process, is attached to this Order as Attachment A.

The first Working Group meeting will be on Friday April 29th from 10:30 a.m. to 4:30 p.m. A detailed agenda and location for the first meeting will be posted to the PUC website by April 18th and circulated to the selected Working Group members and alternates (see below).

Raab in consultation with Commission staff will establish the Working Group, which will include membership based on knowledgeable, diverse, and comprehensive stakeholder organization interests with the need for a manageable Working Group size and process. We expect that Eversource, Unitil, and Liberty Utilities will fully participate in the Working Group process. Other stakeholder groups that are interested in fully participating (i.e., prepare for and participate in all the working group meetings) need to notify Debra Howland, Public Utilities Commission Executive Director, of their interest by April 11th. Notification should include the organization name; the names, addresses, phone numbers, and email addresses for lead representative and any alternate; along with a brief explanation of the organization’s interest and expertise in the matters covered by this Working Group process. Organizations with similar interests are encouraged to work together (e.g., share a seat as a lead and alternate). Working Group members and alternates will be notified by April 18th, and the Working Group will be posted on the PUC website. Parties and members of the public will have an opportunity to comment on the Working Group's recommendations after the final report is issued.

IV. Questions on the Status of the Grid in New Hampshire

In order to provide a foundation for this inquiry, we require an understanding of the current grid infrastructure in New Hampshire and its capabilities, as well as the status of the grid modernization activities in process or being planned. Attachment B includes a set of questions to the electric utilities to obtain this information. The responses to these questions will be provided to the members of the Working Group, and will be used to assist in the discussions, proposals, and recommendations of the Working Group. The electric utilities shall provide responses to these requests within three weeks of the date of this order.

Based on the foregoing, it is hereby

ORDERED that Eversource, Unitil, and Liberty shall participate fully in the Working Group process described in this Order and shall answer questions contained in Attachment B to this Order within three weeks of the date this Order is issued; and it is

FURTHER ORDERED that any party wishing to participate in the Working Group process described above provide notice to the Commission's Executive Director in writing on or before April 11, 2016; and it is

FURTHER ORDERED that the first Working Group meeting shall be held at the Commission at 21 South Fruit Street, Concord, New Hampshire on April 29, 2016, beginning at 10:30 a.m.

By order of the Public Utilities Commission of New Hampshire this first day of April, 2016.

Martin P. Honigberg Chairman	Robert R. Scott Commissioner	Kathryn M. Bailey Commissioner

Attested by:

Debra A. Howland
Executive Director

Attachment A

Stakeholder Process Work Plan

	Outcomes & Capabilities	Data Gathering	Distribution System Planning	Customer Engagement (rate design, meters, etc.)	Cost Recovery/Incentives	Final Report
SH Mtg. #1: April 29	Introduce/ Discuss	Introduce/ Discuss				
SH Mtg. #2: May 26	Develop Recommendations	Review	Introduce/ Discuss			
SH Mtg. #3: June 24			Develop Recommendations	Introduce/ Discuss		
SH Mtg. #4: Sept. (TBD)				Develop Recommendations	Introduce/ Discuss	
SH Mtg. #5: Oct. (TBD)					Develop Recommendations	
SH Mtg. #6: Nov. (TBD)	Refine Recommendations		Refine Recommendations	Refine Recommendations	Refine Recommendations	
SH Mtg. #7: Dec. (TBD)	Finalize Recommendations		Finalize Recommendations	Finalize Recommendations	Finalize Recommendations	Detailed Report Outline
SH Mtg. #8 Jan. (TBD)						Review/Finalize

Attachment B

Discovery Requests to the Electric Distribution Companies

The purpose of these questions is to provide the Commission, the Staff, and other stakeholders with a general understanding of the current grid infrastructure in New Hampshire, as well as the status of the grid modernization activities in process or being planned. We direct the electric utilities to provide as much of the quantitative data below as possible. To the extent that some of the quantitative data requested is not available, please provide a qualitative description.

Grid-Facing Technologies

1. Please describe the percentage of your transmission and distribution system components that are automated, including:
    a. Substations: the total number, the number automated, and the percent automated.
    b. Feeders: the total number, the number automated, and the percent automated.
    c. Capacitors: the total number, the number automated, and the percent automated.
2. Please provide the percentage of your transmission and distribution system components that have the ability to measure minimum load, including:
    a. Substations: the total number, the number that can measure minimum load, and the percent that can measure minimum load.
    b. Feeders: the total number, the number that can measure minimum load, and the percent that can measure minimum load.
    c. Line Sections: the total number, the number that can measure minimum load, and the percent that can measure minimum load.
3. Please provide the percentage of your transmission and distribution system components that are capable of reverse power flow, including:
    a. Substation transformers: the total number, the number that are capable of two-way power flow, and the percent that is capable of two-way power flow.
    b. Substation regulation: the total number, the number that are capable of two-way power flow, and the percent that is capable of two-way power flow.

c. Feeder regulation: the total number, the number that are capable of two-way power flow, and the percent that is capable of two-way power flow.

4. Please provide the information on the type and location of the network system enablers. The information should be sufficient to at least fill in the table below:

Type and Location of Network Capabilities		
Capability	System Location: (transmission, distribution, substation, other)	Notes
Fault Detection, Isolation, Restoration (FDIR)		
Automated Feeder Reconfiguration		
Integrated Volt/VAR Control, Conservation Voltage Reduction		
Remote Monitoring & Diagnostics (equipment conditions)		
Remote Monitoring & Diagnostics (system conditions)		
Others		

<u>Customer Engagement</u>

For the customer engagement information requested below, please provide the information by rate class. If the information is not available by rate class, please provide it at a higher level of aggregation.

5. For each rate class, please provide the total number of customers.

6. For each rate class, please provide the total number of customers that currently participate in any one of the following rate offerings:

   a. Flat energy rates
   b. Inclining block rates
   c. Declining block rates
   d. Seasonal rates
   e. Time of use rates
   f. Critical peak pricing
   g. Peak-time rebates

7. For each of the responses to the previous question, please describe (a) whether the rate offering is mandatory, opt-out, or opt-in; and (b) the current value of the rates offered.

8. For each rate class, please provide the total number of customers that have participated in any one of the following programs, for each year for 2006-2015:

    a. Energy efficiency

    b. Demand response

9. For each rate class, please provide the total number of customers that currently have any one of the following behind-the-meter technologies installed:

    a. Photovoltaics

    b. CHP

    c. Other types of distributed generation

    d. Plug-in electric vehicles

    e. Batteries or other storage devices

<u>Meter Capabilities</u>

10. Please provide an annual schedule of the installation date of all of your current meters by filling in following table:

Year	Number of Meters Installed in Year	Number of AMR Meters Installed	Number of AMI Meters Installed
first relevant year …			
2010			
2011			
2012			
2013			
2014			
2015			
Total Current Meters			

Please provide the data by meter type (e.g., energy or demand), by customer size (e.g., up to 200 kW), or by customer class, to the extent that the information is relevant and readily available for your company.

For the purpose of responding to this question, AMR (automatic meter reading) includes a system where aggregated kWh usage, and in some cases demand, is retrieved via an automatic means such as a drive-by vehicle or walk-by handheld system.

For the purpose of responding to this question, AMI (advanced metering infrastructure) includes a system AMI a metering system that records customer consumption hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point

11. For all of the meters currently installed on the Company's system, please provide the following information:

    a. Average meter book life
    b. Average assumed meter operating life
    c. Average meter age
    d. Average expected meter life remaining (which should equal the difference between assumed operating life and age).

12. Please describe the Company's current practice for replacing meters when they are no longer operable. Does the Company simply replace when a meter fails, or is there a regular replacement schedule? If so, please describe including whether meters are being replaced with like meters or more advanced meters.

13. Please describe the various options available to the company when a current meter fails or requires replacement (e.g., replacing end points, replacing other components, replacing the entire meter). Please describe the company's policy for choosing among these options, and explain which options are most frequently taken.

14. When a decision is made to replace a meter, what type of meter is chosen, and why? What functions do the replacement meters offer?

15. For each customer class, please provide the number of customers that currently have meters with the following capabilities:

    a. Drive-by meter reading
    b. Time-of-use register
    c. Reading of interval data
    d. Daily reading at the Company's office
    e. On-demand / real-time meter reading
    f. Communication to meter from the Company
    g. Communication from meter to customer end-use equipment
    h. Remote switch for service connection / disconnection.
    i. Power quality reading
    j. Outage identification and restoration notification
    k. Planning data (snap-shot demand and system reads).