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July 25, 2006

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street Suite 10
Concord, NH 03301

Re: DE 06-061
Investigation of New Federal Standards Required by the Energy Policy Act 2005
Proposed Scope of Investigation

Dear Ms. Howland:

On April 24, 2006, the New Hampshire Public Utilities Commission (Commission) issued an Order of Notice regarding the Energy Policy Act of 2005(EPAct). As stated in the Order of Notice, the EPAct was signed into law on August 8, 2005. Sections 1251, 1252 and 1254 of the EPAct require state commissions to consider five new federal standards that have been added to Title I of the Public Utility Regulatory Policies Act, and to make specific determinations as to whether implementation of the standards is appropriate. The five new standards are Net Metering, Fuel Source Diversity, Fossil Fuel Generation Efficiency, Time-Based Metering and Interconnection. The Order of Notice includes the time frames for consideration of each standard by state commissions.

Pursuant to the Order of Notice, a prehearing conference was held on May 16, 2006. Following the prehearing conference, the Parties and Staff developed a document which delineates the scope of the investigation for each of the five standards to which all parties agreed. The Parties and Staff also agreed that Staff would file with the Commission the consensus scoping document, and Parties with additional comments would file them separately.

The Staff hereby files the consensus scoping document. We request the Commission to review the document and to issue an order accepting or modifying the scope of the investigation. We also recommend that the Commission give priority to the investigation of Time-Based Metering and Interconnection because the EPAct offers a shorter time for Commission review of these two standards. Once the Commission issues an order, Staff and the Parties will propose a procedural schedule for the investigation.

I have provided a copy of this letter to everyone on the service list.

Please let me know if you have any questions.

Sincerely,

Suzanne Amidon
Staff Attorney/Hearings Examiner

Enclosure

Service List

DE 06-061
Time Based Metering and Communications ("Smart Metering")
Section 1252 of Energy Policy Act of 2005

Timing Issues
Compliance deadlines are different than other sections and are a bit confusing. The standard states "not later than 18 months after the date of enactment .....each electric utility shall offer each of its customer classes.... a time based rate schedule." If strictly adhered to, this would be before the end of the two year regulatory decision making period. Regulatory authorities can alter the time period within the standard to accommodate their schedules and practical limits of a utility program. Section 1252(g) of the Act then reverts to similar language as the first three standards in the new law.

The Standard

Utilities must offer a Time Based Rate Schedule to each customer class within 18 months (February 18, 2007) after the date of enactment.

> Rate varies by time period and rate reflects variance, if any, in the cost of generating/purchasing at wholesale level.
>
> Rate enables consumer to manage energy use and cost through smart metering.

The types of time based rate schedules that may be offered include:

> Time of Use pricing (TOU): price is broken into two or three time periods based on typical demand levels (peak, shoulder, off-peak) and is fixed for a predetermined period.
>
> Critical Peak Pricing (CPP): the price is similar to TOU in most hours except it allows the utility to increase prices to a substantially higher level during extreme peak hours.
>
> Real-Time Pricing (RTP): Prices are provided in real-time or near real-time with price notification from one hour to one day prior to use. This requires customers to monitor both price and usage in much more detail.
>
> Credits under peak load reduction agreements that reduce a utility's planned capacity obligations:

Each electric utility shall provide each customer requesting a time based rate with a time based meter capable of enabling the utility and customer to offer and receive such rate, respectively (also applies to customers whose energy is provided by a third party marketer).

Regulatory authority must conduct investigation within 18 months, or February 8, 2007, commencing within 12 months (Aug. 8, 2006) and completing within 24 months (Aug. 8, 2007):

> Determine whether or not it is appropriate for electric utilities to provide and install time based meters and communications devices for each of their customers which enable such customers to participate in time based pricing rate schedules and other demand response programs.

Prior State Action – The Standard shall not apply in the case of any electric utility in a state, if before the enactment of the provision:

> The state has implemented for such utility the standard concerned;
>
> The state regulatory authority has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility within the previous three years; or
>
> The state legislature has voted on the implementation of such standard for such utility within the previous three years.

Goal of the Standard - To encourage conservation of energy supplied by electric utilities and optimize efficiency of electric utilities' facilities and resources:

> Allow consumers to pay prices that more accurately reflect the cost of providing the service.
>
> Properly designed time based rates are intended to provide price signals to consumers so they can make decisions on when or whether to use electricity.
>
> Reductions in peak demand can lead to reduced transmission congestion, possibly allowing lower cost imports to enter the market.
>
> Reductions in peak demand may permit more expensive generators to run less often and may reduce the need for the addition of peaking capacity.

Issues

1. Has the state or the Commission already taken any action that may constitute "prior state action" under the Standard?
2. Qualitatively, what are the costs and benefits of time-based pricing for default service?
3. Which costs are the responsibility of customers and which are the responsibility of competitive suppliers?

4. What is the experience with "real time" pricing as a means to encourage demand response and promote retail access? What are the implications of this experience for implementing "real time" pricing in NH?
5. Can the demand response benefits of "real time" pricing be achieved without the installation of energy management control systems?
6. What are the operational benefits (e.g., fewer estimated readings, meter reading labor cost savings, load data for engineering analysis, more efficient outage management, remote connect and disconnect functionality, and improved customer service) and challenges associated with smart meters?
7. Which time-based rate structure is appropriate for each customer class in each utility?
8. Does the standard raise factual issues that should be considered on a utility-by-utility basis? For example, does 369-B:3IV(1)(A) prohibit "real time" pricing for any PSNH customer class?[1] In addition, does the statutory requirement that UES and National Grid procure their power requirements in the market prohibit time-based pricing for any customer class?
9. Should implementation of time-based pricing be mandatory, voluntary, or some combination of the two?
10. What are the available technology options for measuring energy and demand on an interval basis? What are the strengths and weaknesses of each? Which technologies make the most sense for each utility and each customer class?
11. What are the available technology options for communicating with interval meters and transmitting the price or cost information to utility and customer? What are the strengths and weaknesses of each? Which technologies make the most sense for each utility and each customer class?
12. What is the current availability of interval meters and communications equipment and systems by customer class? What is the timeline for acquiring such capability if not currently available?
13. Does each utility currently have the capability to bill customers based on "real time" pricing? If not, what is the timeline for acquiring such capability and what changes need to be made?
14. What are the monetary costs and benefits of time-based pricing?
15. What implementation issues should be considered? For example, should utilities develop education and outreach plans, develop targeted technical assistance programs, and/or implement pilot programs? What would these efforts entail?
16. How should existing default service wholesale supply contracts be treated if time-based or "real time" default service is implemented and starts before the end of the existing contract(s)?
17. What "real time" pricing information is available and how will it be communicated to customers? What adjustments do utilities expect to make to these "real time" prices?
18. How will "real time" prices be reconciled with actual supply prices? How should these cost differences be collected from customers? Can the utilities provide

[1] In regard to all subsequent questions that relate to "real-time" pricing, PSNH is asked to assume that RSA 369-B:3IV(1)(A) is amended in such a way that it will have the ability to implement such pricing for large customers.

billing information on an hourly basis which reflects both real time price and eventual settlement price?

19. How will this information be used? What control equipment is available on the customer end? If pricing information is provided, what technology exists to take this information and use it to control load based on pricing inputs?

DE 06-061
Interconnection of Distributed Resources
Section 1254 of the Energy Policy Act of 2005

Timing Issues

Not later than 1 year after enactment of the standard (August 8, 2006), each state regulatory authority shall commence consideration or set a hearing date for consideration, with respect to the standard.

Not later than 2 years after enactment of the standard (August 8, 2007), each state regulatory authority shall complete the consideration and shall make a determination as to whether to adopt the standard.

The Standard

Each utility shall make available upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "interconnection service" means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies.

Prior State Action

The standard shall not apply in the case of any electric utility in a state, if before enactment of the provision:

> The state has implemented for such utility the standard concerned;
>
> The state regulatory authority has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility; or
>
> The state legislature has voted on the implementation of such standard or a comparable standard for such utility.

Issues

1. What are the current interconnection practices and policies of each NH utility?

2. Has the state or the Commission already taken any action that would constitute prior state action under the Standard? For example, do the interconnection provisions in PUC 900 Rules: Net Metering for Customer-Owned Renewable Energy Generation Resources of 25 Kilowatts or less qualify as a comparable standard?
3. What is an appropriate definition of on-site generator under the Standard?
4. Should NH adopt a standard interconnection policy for all utilities? If not, why not? If so, what should the policy be and who should it apply to?
5. Should the standard apply to all new on-site generators regardless of size? If not, what are appropriate size limits under the standard? Should the standard apply to existing projects?
6. What are the best practices for designing effective interconnection standards that balance the needs of utilities, owners of on-site generation and the public?
7. Review existing NH procedures and determine whether they encompass IEEE Standard 1547 and whether they are consistent with "best practices" and are "reasonable, and not unduly discriminatory or preferential."
8.. What are the advantages and disadvantages of: (i) adopting the IEEE 1547 interconnection standard; (ii) adopting NARUC's "Model Interconnection Procedures Agreement for Small Distributed Generation Resources" or (iii) applying FERC's interconnection rules (FERC Order 2006) to NH on-site generators?

DE 06-061
Fuel Sources
Section 1251 of the Energy Policy Act of 2005

Timing Issues

Not later than 2 years after enactment of the standard (August 8, 2007), each state regulatory authority shall commence consideration or set a hearing date for consideration, with respect to the standard.

Not later than 3 years after enactment of the standard (August 8, 2008), each state regulatory authority shall complete the consideration and shall make a determination as to whether to adopt the standard.

The Standard

Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

State Action

A. The Commission is free to adopt the standard, adopt the standard in part, or decline to adopt the standard.

B. The Commission need not take up the standard if:

(1) the Commission has implemented the standard concerned (or a comparable standard);

(2) the Commission has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard); or

(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.

Current Status of PSNH's Fuel and Power Supplies

A. PSNH's existing generation portfolio
   1. Coal - Merrimack I and II (coal only) and Schiller Units 4 and 6 (coal and oil capable)
   2. Wood – Schiller Unit 5 (wood and coal capable)
   3. Residual Oil – Wyman Unit No. 4
   4. Dual Fuel - Newington (Oil and natural gas capable)
   5. Hydro
   6. Distillates (kerosene and/or diesel - (Combustion turbines at White Lake, Schiller (natural gas also), Merrimack, and Lost Nation)
   7. Nuclear – Vermont Yankee

In addition, PSNH is negotiating to purchase long-term power supplies with developers of wind power projects located in New Hampshire.

B. PSNH's fuel purchasing
   1. Coal, - mix of multi-year and spot contracts; domestic and foreign suppliers; rail, ship, barge and truck deliveries
   2. Residual and distillate oil – Mix of annual and spot contracts; multiple suppliers delivered by barge, ocean vessel, rail and truck.
   3. Wood supply – Multiple suppliers from three states

C. PURPA Independent power producers. New Hampshire's regulatory scheme of encouraging off system power producers has led to the development of 54 megawatts of hydro, 84 megawatts of wood fired generation, 41 megawatts of waste to energy (trash plants, landfill gas).

D. Only a portion of PSNH's energy requirements are supplied with own generation and PURPA contracts. The remainder is acquired in the wholesale market under spot and bilateral purchases. The restructured New England wholesale generation market comprises regulated and non-regulated generators with a diverse fuel mix. In addition to PSNH's own generation, the three largest wholesale merchant plants located in New Hampshire comprise 1,200 megawatts of nuclear power and 1,245 megawatts of natural gas combined cycle.

Issues

1. Application of standard to Unitil and National Grid.
   a. Should RFPs for default service include a requirement that power supply be generated from diverse fuels/sources? For example, would such a requirement be contrary to the requirement that the power supply for default service be acquired in the competitive market (RSA 374-F: 3, V(c))?
   b. Should RFPs for default service include a requirement that a percentage of the power supply be generated from renewable fuels/sources? For example, given recent legislative activity in regard to renewable portfolio standards, is this an

issue the Commission should undertake on its own? What regional forums or actions regarding fuel diversity should New Hampshire participate in or be mindful of, if any?

2. If the standard does not apply to Unitil and National Grid, should the parties recommend that the proposed standard be rejected because New Hampshire is not dependent upon a single source of fuel?
3. Is the substance of the fuel diversity plan called for in the standard already included in the state's IRP statute? If so, does the IRP statute constitute prior state action? If not, would it be appropriate to amend the IRP statute to include such a plan rather than establish a separate standard?
4. Will the proposed standard conflict with existing or future limits on environmental emissions? If yes, can these environmental and fuel diversity goals be reconciled?
5. What is an appropriate level of fuel diversity for PSNH? To the extent that PSNH needs to improve its fuel diversity, what will be the cost to ratepayers and the state' competitiveness to make that improvement?
6. Assuming the Commission has the authority to require PSNH to change the diversity of its fuel sources, what standard should the Commission adopt to guide the next generation of resources?

DE 06-061
Fossil Fuel Generation Efficiency
Section 1251 of the Energy Policy Act of 2005

Timing Issues

Not later than 2 years after enactment of the standard (August 8, 2007), each state regulatory authority shall commence consideration or set a hearing date for consideration, with respect to the standard.

Not later than 3 years after enactment of the standard (August 8, 2008), each state regulatory authority shall complete the consideration and shall make a determination as to whether to adopt the standard.

The Standard

Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation. (Assume this standard applies only to PSNH.)

State Action

A. The Commission is free to adopt the standard, adopt the standard in part, or decline to adopt the standard.

B. The Commission need not take up the standard if:

(1) the PUC has implemented the standard concerned (or a comparable standard);

(2) the PUC has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard); or

(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.

Historical Perspective

Definition of efficiency – Involves equipment upgrades and replacements, system operational improvements, overall station performance.

Planned outages, periodic overhauls, capital improvements focus on maintaining and/or improving efficiency and reliability of existing generation fleet.

Pollution control additions negatively affect efficiency and increase station load

Recent Accomplishments

1. Provide examples of recent projects where value of efficiency gains can be defined or estimated and current or future benefits will result.
2. What typical efficiency gains are achieved during annual outages?
3. What maintenance or capital projects are planned which will provide improvements or value?

Projects In Process/On the Drawing Board

Issues

1. Whether the requirement to consider fossil fuel generation efficiency is already captured in New Hampshire's IRP statute. If yes, should the plan be included in a future IRP or Default Service filing? If not, would be it be more efficient to amend the statute or develop a separate rule?

2. What factors should be considered in deciding to pursue efficiency improvements?
   A. Benefit/Cost ratio
   B. Payback in years
   C. Environmental benefits
   D. Effect upon reliability
   E. Regulatory considerations
      1. Modification or addition to plant net output
      2. Required projects
      3. Timely cost recovery
   F. Reduced or increased maintenance activities
   G. Measurable efficiency improvement
   H. Availability of funds and cost impact on customers

Development of Plan

A. Short and long term plan
   1. Major equipment – repair or replace.
   2. Key systems
   3. Minor equipment – repair or replace
B. Develop hierarchy of priorities
   1. Reliability - most critical in base load plants
   2. Efficiency - critical in base load plants
   3. Cycling capability – most critical in intermediate + peaker plants.

DE 06-061
Net Metering
Section 1251 of the Energy Policy Act of 2005

Timing Issues

Not later than 2 years after enactment of the standard (August 8, 2007), each state regulatory authority shall commence consideration or set a hearing date for consideration, with respect to the standard.

Not later than 3 years after enactment of the standard (August 8, 2008), each state regulatory authority shall complete the consideration and shall make a determination as to whether to adopt the standard.

The Standard

(11) Net metering. Each electric utility shall make available upon request net metering service *to any electric consumer* that the electric utility serves. For purposes of this paragraph, the term "net metering service" means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

State Action

A. The Commission is free to adopt the standard, adopt the standard in part, or decline to adopt the standard.

B. The Commission need not take up the standard if:

(1) the PUC has implemented the standard concerned (or a comparable standard);

(2) the PUC has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard); or

(3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility.

Issues

1. How should the net metering standard be interpreted? Specifically, does the standard require a customer that uses more electricity than it generated in the month to pay the utility only for the difference? That is, should the customer receive the full retail rate for electric energy generated by its on-site generation facility? Also, if the customer generated more electricity than it used that month, what value should be placed on the excess kilowatt hours? Finally, how should the parties interpret the term "eligible on-site generating facility"?
2. What are the costs and benefits of adopting the standard?
3. Does the Legislature's enactment of RSA 362-A: I-a, III-a and RSA 362-A:9 on Net Energy Metering and the Commission's adoption of NH Code Admin. Rules Chapter Puc 900, which implements the legislation, constitute prior state action and, hence, remove the need for action by the Commission on the standard?
4. If yes, should the parties recommend amending PUC Chapter 900?
   a. Inverter specifications reference out of date IEEE guidelines.
   b. Specific surge test requirements are now incorporated into UL1741 testing that are more stringent than those listed in PUC900.
5. If not, can the Commission change the limits in its net metering rule without prior legislative approval? The limits are: (i) an on-site generator cannot exceed 25 kilowatts (RSA 362-A:1-a, II-b); and (ii) the cumulative capacity subject to net metering cannot exceed 0.05 % of utility's peak (RSA 362-A:9, I). If so, should the Commission do so?
6. Also, can the Commission change the design of its net metering policy? If so, what changes might be appropriate? For example, should all renewable resources be eligible for net metering; should non-renewable sources be eligible; should the size limitation on on-site generators be relaxed; and should the capacity limitation be revised?