EXHIBIT

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PENGAD 800-631-6989

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

DE 15-137

ELECTRIC AND NATURAL GAS UTILITIES

ENERGY EFFICIENCY RESOURCE STANDARD

TESTIMONY

OF

JAMES J. CUNNINGHAM Jr., JAY E. DUDLEY and LESZEK STACHOW

December 9, 2015

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A. INTRODUCTION

Q. Please state your name, current position and business address.

A. My name is Leszek Stachow, and I am employed by the New Hampshire Public Utilities Commission (Commission) as Assistant Director of the Electric Division. My business address is 21 South Fruit Street, Suite 10, Concord, New Hampshire.

Q. Please summarize your educational and professional background.

A. My educational and professional background is summarized in Attachment 1.

Q. Please describe the process whereby Commission Staff is submitting testimony in this case today?

A. Energy efficiency initiatives approved by the New Hampshire Public Utilities Commission (Commission) and primarily coordinated through the Core programs have a rich history in New Hampshire. Close collaboration between electric and natural gas utilities, stakeholders, and Commission Staff (Staff) has resulted in a record of achievement over the past 20 years.

Between 2007 and 2015, a number of studies were performed that suggested that additional opportunities for cost-effective energy efficiency existed beyond those captured by the Core programs. In September 2014, in its report, *New Hampshire 10-Year State Energy Strategy* (State Energy Strategy), the New Hampshire Office of Energy and Planning (OEP) recommended: "The Public Utilities Commission should open a proceeding that directs the utilities, in collaboration with other interested parties, to develop efficiency savings goals based on the efficiency potential of the State, aimed at achieving all cost effective efficiency over a reasonable time frame."

In April of 2014, the Commission directed Staff to investigate the establishment of a state-wide Energy Efficiency Resource Standard (EERS). An EERS establishes specific, long-term targets for energy savings that utilities or non-utility program administrators must meet through customer energy efficiency programs. Staff gathered input from a broad cross section of stakeholders and developed an EERS Straw Proposal (Straw Proposal).

The Commission opened docket IR 15-072 to receive written comments on the Staff recommendations contained in the Straw Proposal. While support for the establishment of an EERS was well received, there were requests for a broader consideration of issues and for making use of outside expertise when establishing the EERS.

On May 8, 2015, the Commission opened this proceeding (Docket DE 15-137) to establish an EERS. In its Order of Notice, the Commission defined the scope of the proceeding to include the following issues: savings targets; funding; program cost recovery; lost revenue recovery; performance based incentives and penalties; program administration; and evaluation, measurement, and verification (EM&V). Following the commencement of the proceeding the Staff and parties engaged in numerous technical sessions, which included expert presentations and the significant exchange of information and ideas. Staff's recommendations in this testimony are informed by those technical discussions as well as Staff's investigation for the Straw Proposal.

B SUMMARY OF THIS TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of Staff testimony is to recommend a structure and a process for Commission establishment and implementation of a successful EERS.

Q. How is your testimony organized?

A. In the next section, Section C, Staff presents an Executive Summary that provides an overview of our recommendations and conclusions concerning implementation of an EERS for New Hampshire. Time lines, savings targets, necessary funding levels and key administrative matters are contained in the Executive Summary. Section D addresses our key conclusions. In section E, Staff explains the division of the testimony and the contributions of each Staff member. Section F provides a high level, industry-wide model illustrating savings targets, costs-to-achieve savings, and cost effectiveness. Section G discusses all associated funding requirements. In Section H, Staff addresses detailed program design matters including administration, safeguarding a robust EM&V policy, and a proposed timeline for EERS implementation. Section I summarizes all of Staff's findings and recommendations.

C. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize Staff's findings and recommendations.

A. The testimony includes twelve recommendations designed to build upon and enhance the scope and effectiveness of the existing Commission-approved Energy Efficiency programs and policy by embracing an EERS.

The following comprise Staff's recommendations:

1. A proposed firm three-year target for energy efficiency savings and a ten-year notional target to be confirmed at the end of the first three-year period.

2. Staff modeling examines two possible sets of targets for the EERS: Plan A comprises a limited plan; and Plan B is a more ambitious plan. Staff recommends approval of Plan B.

Under Plan B and based on a 2014 base year, the three-year proposed cumulative electric savings target is 2.04 percent while the ten-year notional electric savings target is 14.48 percent. The recommended three-year savings target for gas is 2.39 percent while the ten-year notional gas savings target is 13.96 percent. The performance incentives (PI) are 10 percent for both electric and gas utilities

Funding

3. In order to compensate the utilities for lost revenues associated with energy efficiency, Staff recommends the adoption of a lost revenue recovery mechanism for an initial three-year period, to be replaced by a decoupling mechanism in the future.

4. Under Plan B, for electric utilities the three-year funding requirement including PI and LRAM will be $108,215, 077. The equivalent funding requirement for gas utilities will be $32,448,955.

5. For the initial triennium, funding may be achieved by raising the SBC and the LDAC.

6. Under Plan B, to meet the initial three-year targets, assuming primary funding through the SBC and LDAC, the increase in the SBC would be $0.0022 per kWh in year 1 and rise to $0.0170 per kWh in year 10. For gas, the initial three year LDAC rate per therm would be in the range of $0.034 per therm in year 1 and increase to $0.124 per therm in year 10. \

Staff recommends that beyond potential increases in the SBC and LDAC charges, the EERS stakeholders collaborate with the utilities in developing sources of private capital to be implemented following the first three-year period. Possible sources of private capital may include loan portfolio sales as well as asset-backed securitization.

Implementation

1. Staff recommends a permanent EERS Advisory Council (Advisory Council) be formed. The Advisory Council would have as its primary role the development of consensus among EERS stakeholders and recommendations for Commission administration of a successful EERS. The Commission could designate the existing EESE Board to fulfill the role of the Advisory Council and authorize the recovery of funds through the SBC and LDAC for additional resources for the EESE Board. For example, to ensure the success of the EERS, Staff recommends that the Advisory Council be provided sufficient funds to hire an independent facilitator to manage the agenda, moderate discussions, and motivate consensus, and subject-matter experts to inform policy recommendations.

2. In looking to the future, Staff recommends that the Commission consider evolving the EERS to include more "deep dive" applications than the existing Core programs in order to maximize participation by all rate classes and income groups. In the short-term, programs could be expanded to include greater use of performance contracting, Custom Data Centers, and, where appropriate, voltage reduction /high efficiency transformer optimization. The long-term scope of energy efficiency could be influenced by Commission progress within the broad area of demand response and smart grid technology.

3. Staff considers EM&V to be a vital part of a successful EERS program and recommends that funding be set aside for a New Hampshire specific Training Resources Manual (TRM).

4. Start Date: Staff recommends that the EERS commence January 1, 2017.

Q. Would you provide an overview of the Staff Model that derives savings, cost-to-achieve savings, and associated rate impacts.

A. Staff testimony provides two options for Commission consideration – Plan A and Plan B. Both options are developed from a Staff Model that represents a high-level, industry-wide model in which savings and cost-to-achieve savings are consolidated for the electric utilities (Eversource, Liberty, Unitil and NHEC) and the gas utilities (Energy North and Northern).

Q. Please describe the savings and cost-to-achieve savings for the electric and gas utilities.

A. The electric utilities are described first both under Plan A and Plan B.

<u>Electric Utilities</u>: (*see* Attachment 2A for more information)

Plan A: For electric utilities, savings goals reach approximately 1.049 billion kWh by the tenth year, 9.74 percent of 2014 actual electric kWh usage. Annual savings goals increase from 58 million kWh savings in 2017 to 171 million kWh savings in 2026.

The estimated cost over ten years to achieve this savings goal is $555 million. Estimated annual SBC costs increase from approximately $22 million in 2017 to $101 million in 2026. The estimated SBC rate required to achieve these savings goals increases from $0.0020 per kWh in 2017 to $0.0092 per kWh in 2026.

Plan B: For electric utilities, savings goals reach approximately 1.559 billion kWh by the tenth year, 14.48 percent of 2014 actual electric kWh usage. Annual savings goals increase from approximately 61 million kWh savings in 2017 to 310 million kWh savings in 2026. The estimated cost over ten years to achieve this savings goal is $867 million. Estimated annual SBC costs increase from approximately $23 million in 2017 to $187 million in 2026. The estimated SBC rate required to achieve these savings goals increases from $0.0022 per kWh in 2017 to $0.0170 per kWh in 2026.

<u>Gas Utilities</u>: (*see* Attachment 2A for more information)

Plan A: For gas utilities, savings goals reach approximately 2.5 million MMBtu by the tenth year, 10.20 percent of 2014 actual gas MMBtu usage. Annual savings goals increase from 163 thousand MMBtu savings in 2017 to 374 thousand MMBtu savings in 2026. The estimated cost over ten years to achieve this savings goal is $164 million. Estimated annual LDAC costs increase from approximately $8.7 million in 2017 to $26.5 million in 2026. The estimated LDAC rate required to achieve these savings goals increases from $0.0324 per therm in 2017 to $0.0791 per therm in 2026.

Plan B: For gas utilities, savings goals reach approximately 3.5 million MMBtu by the tenth year, 13.96 percent of 2014 actual gas MMBtu usage. Annual savings goals increase from 172 thousand MMBtu savings in 2017 to 601 thousand MMBtu savings in

2026. The estimated cost over ten years to achieve these savings goal is $224 million. Estimated annual LDAC costs increase from approximately $9.1 million in 2017 to $41.5 million in 2026. The estimated LDAC rate required to achieve these savings goals increases from $0.0342 per therm in 2017 to $0.1241 per therm in 2026.

D. FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. Staff's findings and recommendations are as follows.

(a) Staff believes that there is intrinsic value in defining both a short run (3 year) and long run (10 year) target for the EERS. Staff has proposed both a limited (Plan A) and more ambitious (Plan B) set of targets for both electrical and gas utilities and indicated their comparative significance in terms of kWh of savings accomplished compared to a base period.

The targets are as follows:

Table 1. Plan A and Plan B Savings Targets

	3 year cumulative savings target, Electric	**10 year cumulative savings target, Electric**	**3 year cumulative savings target Gas**	**10 year cumulative savings target, Gas**
Plan A	1.82%	9.74%	2.14%	10.20%
Plan B	2.04%	14.48%	2.39%	13.96%

Since targets can only reasonably be proffered when accompanied by a suitable level of funding, the testimony provides estimates of the associated funding requirements necessary to meet Plan A and Plan B savings goals, respectively.

b) Staff developed a modeling tool (see Attachment 2) that demonstrates the relationship between targets and funding needs year-by-year for both Plan A and Plan B. Staff has further modeled funding outcomes that consider the application of a lost revenue adjustment mechanism (LRAM) which is incorporated in the SBC and LDAC among other options available to the Commission. Cumulative funding requirements[1] to achieve short term energy savings targets are as follows:

Table 2. Plan A and Plan B 3-year Funding Requirements

	3-year Funding requirement with PI and LRAM - Electric	**3-year Funding requirement, with PI and LRAM - Gas**
Plan A	$95,600,645	$29,007,902
Plan B	$108,215,077	$32,448,955

(c) Staff has proposed a range of funding mechanisms to meet the budgetary requirements. Budgetary requirements necessary to meet the first three years of Plan A and Plan B may be found in Attachment 2. Proposed mechanisms to meet those budgetary requirements include the following: adjusting the SBC and LDAC charges among other options available to the Commission.

[1] Funding sources for electric utilities energy efficiency programs include SBC, RGGI and ISO-NE (Forward Capacity Market).

Although not incorporated in the modeling tool, other mechanisms include a tariff recovery mechanism, raising rates, as well as alternative funding mechanisms such as revolving loan funds, asset backed securitization, etc. Further information on funding may be found in Section F.

(d) Staff has proposed a mechanism for administering the EERS program that leverages the positive experience of the existing Core programs and relies heavily on the collaboration between utility assigned Program Administrators and a permanent EERS Advisory Council.

(e) Staff has proposed an expansion in the portfolio of services /eligible efficiency measures that would form part of the initial three-year EERS program that builds on services/eligible efficiency measures incorporated in the 2016 Core Update. Additionally, Staff has provided additional recommendations concerning possible parallel actions that the Commission may wish to consider that will serve to enhance EERS implementation over the medium-term. These actions may include implementing policy with respect to demand response and smart grids.

(f) Staff has provided recommendations that will enable collaborative work with the utilities in the implementation of a more robust EM&V mechanism in the medium-term that will be well suited to address emerging issues and technologies. This mechanism anticipates making use of outside EM&V consultants hired by the Advisory Council and approved by the Commission to strengthen the process.

(g) Finally, leveraging the Core programs, Staff proposes a 3-year timeline for implementation.

E. DIVISION OF COMMISSION STAFF ANALYSIS

Q Describe the structure of Staff testimony and its various contributors.

A. In order to permit the Commission and other intervening parties to fully understand the positions and recommendations of Staff, we are providing the testimony of the following three Staff witnesses:

Mr. Cunningham, a utility analyst in the Commission's Electric Division (Electric Division), presents a high level industry-wide model that will correlate proposed targets under Plan A and Plan B with the associated level of kWh savings and with the required funding level needed to achieve those savings. Mr. Cunningham's educational background and experience can be found in Attachment 1.

Mr. Dudley, a utility analyst in the Electric Division, addresses current levels of funding available under Core and how they may meet the needs of Plan A and Plan B. Considering best practices from other jurisdictions, Mr. Dudley also discusses the availability of alternative funding mechanisms that may be available to the Commission. Mr. Dudley's educational background and experience can be found in Attachment 1.

Mr. Stachow, Assistant Director of the Electric Division, addresses the possibilities presented by private sector capital, proposed changes in the existing structure and process used by the Commission to administer energy efficiency policy, EM&V needs, and a suggested time line for implementation. Mr. Stachow's educational background and experience can be found in Attachment 1.

F. PROPOSED EERS TARGETS

Q. Please explain how this section is organized.

A. This section is divided into two parts: Guiding Principles; and Target Setting. The first part provides historical perspective and general comments about the Model methodology including references to Commission Orders, the State's 10-year Energy Strategy (State Energy Strategy), a recent legislative mandate, and supporting schedules attached to Staff testimony. Target Setting provides more detail about the Model and this detail is found in Attachment 2.

<u>Guiding Principles</u>

Q. Please describe the principles that Staff believes should guide the EERS development process?

A. The guiding principles used in the Model include the following:

- <u>Building out</u>: Building out from our current programs, reflecting Commission guidelines, orders, and protocols established and implemented over the past two decades to administer energy efficiency policy.

- <u>Reflect recommendations</u>: Ensuring that EERS reflect recommendations in the State Energy Strategy, a recent change in the law, and American Council for an Energy Efficient Economy (ACEEE) recommendations.

- <u>Challenging Targets:</u> Setting challenging but achievable state-wide savings targets that are consistent with other New England states and that are reflective of the GDS Report (January 2009) and the VEIC Report (November 2013).

Q. Please summarize the Commission's energy efficiency policy as you understand it.

A. Some of the Commission guidelines, orders and protocols that inform Staff's recommended EERS design are summarized below.

- Benefits of Energy Efficiency: In an order regarding the conservation and load management programs of Granite State Electric Company, the Commission said that energy efficiency programs produce two benefits: (1) the benefit to all ratepayers of meeting resource needs at lower costs and (2) direct benefit to customers who participate in the programs and therefore have lower bills. *Connecticut Valley Electric Company, Inc.*, 76 NH PUC 495 (Order No. 20,186 (July 23, 1991).

- Recovery Mechanism: The N.H. Legislature authorized the Commission to include a system benefit charge (SBC) for collection by the electric distribution utilities to be used to fund public benefits related to the provision of electricity, including energy efficiency programs. RSA 374-F:3, VI. The Commission adopted the SBC for purposes of funding electric energy efficiency programs in *Energy Efficiency Programs*, Order No. 23,574 (November 1, 2000). The Commission adopted settlement for the reinstitution by two gas local distribution companies of certain energy efficiency initiatives in *Energy-efficiency Programs for Gas Utilities*, Order No. 24,109 (December 31, 2002). The approved settlement authorized the utilities to recover costs for those programs through the utilities' local distribution adjustment clause (LDAC). *Id.*

- Budget Allocations: In a proceeding pre-dating restructuring, the Commission approved a settlement requiring that the relative investment in conservation load management among various customer groups should not deviate excessively from the relative electricity sales to the various customer sectors. *Public Service Company of New Hampshire*, Order No. 23,172 (March 25, 1999).

- Cost Recovery: Commission approved a settlement authorizing the utilities to have a reasonable opportunity to recover its costs for programs prudently implemented. *Public Service Company of New Hampshire*, Order No. 23,172 (March 25, 1999).
- Core Programs: Commission approved a settlement agreement that establishes energy efficiency program commitments, funding mechanisms, and monitoring and evaluation procedures for electric utilities. Joint Petition for Approval of Core Energy Efficiency Programs, Order No. 23,982 (May 31, 2002). The Commission adopted settlement for the reinstitution by two gas local distribution companies of certain energy efficiency initiatives in *Energy-efficiency Programs for Gas Utilities*, Order No. 24,109 (December 31, 2002). The approved settlement authorized the utilities to recover costs for those programs through the utilities' local distribution adjustment clause (LDAC).

- Cost Effectiveness: Commission approves and defines parameters of the Total Resource Test (TRC) for cost effectiveness testing. *Energy Efficiency Programs*, Order No. 23,574 (November 1, 2000) at 4-5 and 15-16.

- Cost effectiveness of Low Income Programs: Energy efficiency working group recommends approval of education and low income programs that fall below a benefit cost ratio of 1.0, and the Commission observes that well-designed, statewide, low-income energy efficiency programs "could help to alleviate the apparent persistence of 'undesirable market conditions' *Energy Efficiency Programs*, Order No. 23,574 (November 1, 2000).

- Decoupling: The Commission has observed that, with revenue decoupling, there could be a potential to inappropriately shift risks. That is, revenue decoupling could enhance the utility's revenue stability and reduce earnings volatility; hence, revenue decoupling may result in a shift of risk away from the utility and toward the customers. *Energy Efficiency Rate Mechanisms*, Order No. 24,934 (January 16, 2009) at 21-22).
  Also, the Commission concludes that "it would be appropriate to propose revenue decoupling in the context of a rate case in order to avoid single-issue ratemaking." [2]

- Performance Incentives (PI): Performance incentives are based "on actual spending as opposed to budgeted spending and are capped at "no more than 5% above the budgeted spending." *2011-2012 Core Electric Energy Efficiency and Gas Efficiency Programs*, Order No. 25,189 (December 30, 2010) at 9-10 and 22-23. Performance incentives associated with fuel-neutral programs are calculated using a "new ratio of electric lifetime savings to total lifetime energy savings" and "the individual components used to calculate performance incentive (the kWh savings and benefit-cost components)" are capped rather than a cap on the overall performance incentive amount for each sector. *2013-2014 Core NH Electric and Gas Energy Efficiency Programs*, Order No. 25,569 (September 6, 2013) at 2-3 and 7. The Commission has disallowed the "grossing up" for tax expense of performance incentives associated with conservation and load management programs, because the utility failed to meet its burden of proof. *Connecticut Valley Electric Company, Inc.*, Order No. 20,359 (December 31, 1991).

- Monitoring and Evaluation: Commission approves impact and process evaluation studies in order to assess energy efficiency programs and measures. *Electric Utility Restructuring*, Order No. 23,574 at 20-22 (November 1, 2000). The Commission approved a settlement, transferring the "direct responsibility for the monitoring and evaluation of the Core energy efficiency programs" from the utilities to the Commission, to allow for "more independent oversight." *Granite State Electric Company et al.*, Order No. 24,599 (March 17, 2006) at 5 and 9-10.

[2] DE 07-064, Order No 24,934.

- Utility Administration: Commission allowed the utilities to continue to administer energy efficiency programs. *Granite State Electric Company et al.*, Order No. 24,599 (March 17, 2006)."

- Fuel Neutral Programs: Commission has approved modified "fuel blind" energy efficiency program. *2009 Core Energy Efficiency Programs*, Order No. 24,974 (June 4, 2009).

- RGGI Funding: Commission approved the use of, and parameters for the use of, RGGI funds in 2012, 2013, and 2014, on Core energy efficiency programs. *2011-2012 Core Electric Programs and Natural Gas Energy Efficiency Programs*, Order No. 25,425 (October 17, 2012).

- Financing: Commission approved a third-party financing pilot program for electric utilities. *2015-16 Core Electric Energy Efficiency and Gas Energy Efficiency Programs*, Order No. 25,757 (December 31, 2014).

Q. Please explain how the Model's savings projections are reflective of criteria in the State Energy Strategy, recent Legislative mandates and ACEEE suggestions.

A. The Model provides two plans – i.e., Plan A and Plan B. Both are supported by the State Energy Strategy and a recent legislative mandate, HB 1540, as follows:

- State Energy Strategy:
  - ➢ The State Energy Strategy calls for updating the strategy every three years beginning in 2017 (p. 1).
  - ➢ The State Energy Strategy calls for development of short-term and long-term goals that ramp up over time to meet new goals (page 25).
  - ➢ Recommendation #6 in the State Energy Strategy calls "Attracting private financing to work with public funds will expand the reach of limited public funds, and will also spur market transformation as more consumers implement efficiency projects and lenders see value in efficiency loans." It also notes that recent efforts such as third-party financing is a step in the right direction because they encourage customers to invest in efficiency on their own and allow banks to get more comfortable with efficiency lending.

- Legislative Mandate:

  - HB 1540 states that it shall be the energy policy of this state, among other things, to maximize the use of cost effective energy efficiency (HB 1540, 378:37).

  - Both Plans meet HB 1540 requirements that consideration be given to the financial stability of the state's utilities (HB1540, 378:37).

Q. Please describe how the Model incorporates and reflects the criteria outlined by ACEEE for an EERS.[3]

A. The Model meets the criteria for an EERS as established by ACEEE as follows:

- Establishes specific energy savings targets that utilities must meet through customer energy efficiency programs.

- Serves as an enabling framework for cost-effective investment, savings, and program activity.

- Provides long- term goals that send a clear signal to market actors about the importance of energy efficiency (EE) in utility program planning, creating a level of market stability.

- Provides sustainable funding sources for electric and gas utility EE programs.

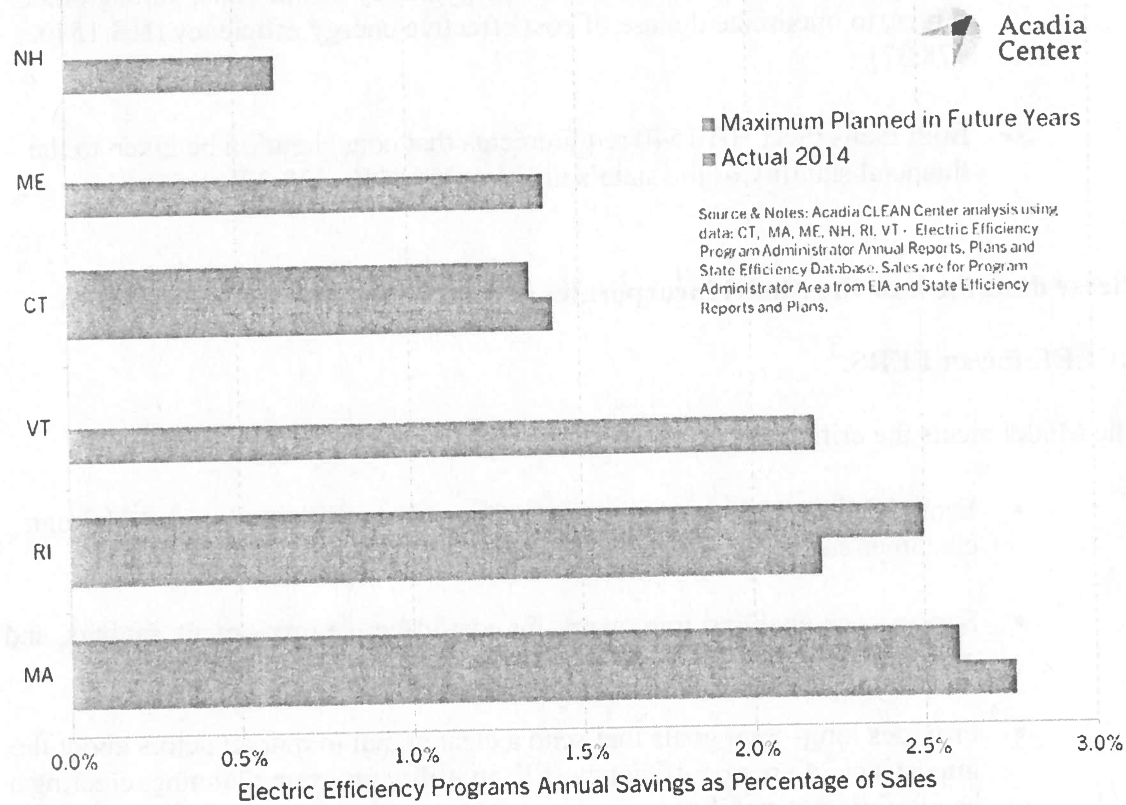
Q. Does the Model reflect savings targets that are comparable to other New England States?

A. The following graph[4] shows the comparison of electric savings goals for the New England States, for the year 2014 (bottom blue line), and projections for future years (top red line):

[3] Ref. ACEEE Report E 1401, at page 6 and ACEEE Report U1403, at page 4.

[4] Source: Graph submitted as part of Acadia Center presentation during EERS Technical sessions held at the PUC in August 2015.

Fig. 1 Electric Savings Goals



[5]

This graph indicates that actual results for 2014 show NH achieved annual savings of approximately 0.6 percent, as a percentage of 2014 actual sales. However, this graph does not provide projections for New Hampshire.

- With the Model's projections included, New Hampshire savings targets, as a percentage of 2014 actual sales, are similar to the other New England projections. Specifically, the Model for Plan A (limited plan) shows annual electric kWh savings projections in the range of 0.6 percent to 1.6 percent, as a percentage of 2014 actual kWh sales. For Plan B (the recommended and more ambitious plan), the annual electric kWh savings range is 0.6 percent to 2.9 percent. (Schedule JJC-1, and JJC-8)

- Also, Staff prepared a summary of Plan B's savings targets, as compared to recent savings targets for other New England states. This comparison confirms that the Plan B savings targets are comparable to the savings targets for other New England states. (Schedule JJC-8).

- For gas utilities, the Model shows annual MMBtu savings projections for Plan A in the range of 0.7 percent to 1.5 percent as a percentage of 2014 actual MMBtu sales; and, for Plan B, in the range of 0.7 percent to 2.4 percent (Schedule JJC-1 and JJC 1-A).

Q. How do the savings targets in the Model compare with those discussed in the VEIC Report (November 2013) and the GDS Report (January 2009)?

A. The Model's savings goals are at or above the potential levels shown in the November 2013 VEIC Report and the January 2009 GDS Report. For instance, the VEIC Report shows that savings (both electric kWh and fossil MMBtu savings converted to electric kWh savings) are 1.75 percent by the end of the fifth year, as a percent of 2012 actual electric kWh usage. By comparison, Plan B shows savings of 4.16 percent by the end of the fifth year, as a percent of 2014 actual electric kWh usage. It's important to note that the VEIC Report counts both electric kWh savings <u>and</u> gas MMBtu savings; while the Model counts only "pure" electric kWh savings for purposes of this comparison.

Plan B savings are consistent with the potential savings identified in the GDS Report. For instance, Plan B shows savings of 14.48 percent pure electric savings by the tenth year, as compared to the GDS Report that shows pure electric savings of 10.8 percent.[5]

[5] GDS labels this 10.8 percent as "potentially obtainable" noting that to achieve this level of projected savings, a concerted, sustained campaign involving aggressive programs and market interventions would be required. The GDS report went on to state that New Hampshire gas and electric utilities would "need to continue to undertake and perhaps aggressively expand its efforts to achieve these levels of savings (GDS Report at page 4).

Q. Since the New England area appears to be most aggressive with respect to EERS target setting, what are the lessons learned from other jurisdictions?

A. Staff reviewed targets from the Midwestern states as a check and balance against the Model projections for New Hampshire and determined that the Model projections are in the range of savings projections for New England states and Mid-Western states. With respect to the Mid-Western states, the table below shows the efficiency targets for six Mid-Western states and the associated ramp up process.

Table 3. Mid-Western States Energy Efficiency Targets[6]

State	Electric Goal	Natural gas Goal	Achieved by	Ramp Up
Illinois	2.00%	1.50%	2015/2017	Under the legislation, utilities were required to meet a goal of 0.2% savings through energy efficiency in 2009, ramping up to 2.0% by 2015 and every year thereafter. However due to a spending cap of 2.015%, the targets for both ConEd and Ameren were lowered by the Illinois Commerce Commission for 2013 ND 2014.
Indiana	2.00%	0%	2019	Utilities were required to reach a goal of 0.3% efficiency in 2010, ramping up an additional 0.2 % yearly through 2018

[6] Midwest Energy Efficiency Alliance, *Energy efficiency Policies, Programs, and Practices in the Midwest, Revised May 2014*, page 76, Appendix a.

				(1.9%) and an additional 0.1% in 2019 to reach a total of 2.0%annual energy efficiency over the course of 10Years
Iowa	1.40%	1.0%	now	There is no state wide goal. Each utility has its own plan and different annual goals. The utility plans reflect a ramp up in the energy savings achieved via energy efficiency
Michigan	1.0%	0.75%	2012/2012	Electric utilities were required to achieve 0.3% savings in 2009; 0.5% in 2010; 0.75% in 2011; and 1.0% in 2012 and each year thereafter. Natural gas utilities were required to achieve 0.1% savings in 2009; 0.25% in 2010; 0.5% in 2011; and 0.75% in 2012 and each year thereafter.
Minnesota	1.50%	1.50%	2010	There was no ramp up schedule provided for in the Next Generation Energy Act of 2007.Legislation also authorized the Minnesota Dept. of Commerce, the regulatory body in Minnesota, to adjust these targets downward. Minimum savings targets are now 1%.
Ohio	2.00%	0	2019	The energy efficiency standard began with a requirement for 0.3% of the preceding three year weighted average electricity sales to be met with efficiency in 2009, ramping up to

				1.0% annually from 2014 to 2018, then increasing to 2.0% in 2019 through 2025.

The analysis demonstrates that EERS targets for electric vary between 1.0 percent to 2.0 percent of annual sales. On the gas side, the equivalent numbers (where they exist) for savings vary from 0.75 percent to 1.50 percent of annual gas sales. In addition, in most cases there has been a gradual ramp-up in implementation from 0.2 percent in the base year in successive increments to 2.0 percent annually after 5 to 8 years. In some cases, more aggressive goals have been scaled back due to spending caps or legislative action.

By way of comparison, the maximum level of savings targeted by the Midwestern States is 2 percent. Our proposed Plan B shows annual savings targets over the 10-year period for the NH electric utilities in the range of 0.5 percent to 2.88 percent, as a percentage of 2014 actual usage. For gas utilities, the Model (Plan B) shows annual savings targets over the 10-year period in the range of 0.7 percent to 2.42 percent, as a percentage of actual 2014 MMBtu usage (Schedule JJC-1).

Q. What was the recommendation arising from the Straw Proposal?

A. The recommendation arising from the Straw Proposal recommended mandatory electric and gas equivalent savings targets for the next 10 years. Staff proposed leveraging the existing Core energy efficiency programs as a point of departure for the EERS target setting. Differentiating between electric and gas utilities, and using 2014 approved base year revenues as a starting point, Staff proposed a gradual increase in the level of electric savings from 2015 to 2025, resulting in cumulative savings of over one billion kWh's, representing 9.76 percent of 2012 kWh electric usage.

On the gas side, Staff proposed a flat annual savings target of 0.70 percent per year from 2017 to 2025 with an initial gradual ramp up in 2015 and 2016 of 0.68 percent and 0.70 percent, respectively. This approach would result in cumulative savings by 2025 of nearly 1.5 million MMBtu's representing 7.63 percent of the 2012 gas MMBtu usage.

Critical for the Straw Proposal was the desire to:

- Move from the known (i.e. Core) to the unknown;
- Gradually change over time allowing the market to adjust to new target conditions;
- Differentiate between electric and gas targets;
- Seek a 10-year target horizon; and
- Set 2012 as the base year from which comparisons would be made.

Q. What other factors should be taken into account when considering EERS targets?

A. Analysis prepared by SEE Action[7] in September of 2011 suggested a list of issues to be considered when setting targets. Amongst the issues were the following:

- Legal authority for setting targets;
- Who the targets apply to (utility, a state agency or other organization);
- Statewide vs utility specific targets;
- Target levels including what savings are included, how they are to be evaluated and specific metrics and baselines to use; and
- How much flexibility to allow and whether to include cost caps.

Each of these issues is considered in the Model as described below.

[7] State and Energy Efficiency Action Network, 2011. *Setting Energy Savings Targets for Utilities*

Legal authority: With respect to legal authority, the Model assumes that in New Hampshire, the Public Utility Commission has the authority to set savings targets and to set rates sufficient to recover all prudent costs incurred to achieve such targets.

Application: Currently, the Commission approves targets that apply to New Hampshire electric and gas utilities.

State-wide versus utility-specific:

To maintain the principle of gradualism and to leverage the experience of the exiting Core programs, the Model assumes that savings targets continue to incorporate savings of state-wide programs and would continue to incorporate savings associated with any utility-specific programs.

Target Savings Levels:

Core programs pursue savings associated with cost effective energy up to the existing level of funding, in the context of annual filings approved by the Commission. The Model captures these projected savings as follows:

- Percentage year-over-year kWh savings increase;
- Annual savings in sales (kWh or MMBtu) relative to 2014 reference year ;
- Cumulative savings in kWh and as a percentage of 2014 kWh sales or 2014 MMBtu sales; and

- Related benefit dollars are estimated for purposes of cost-effectiveness calculations.

In addition, a 10- year time horizon is established with fixed targets for the first 3-year period, with 'guideposts' for the remaining 7-year period to be reviewed and updated based upon the initial experience and performance achieved during the first 3-year period.

Flexibility:

The Model assumes that the utilities are focusing on demand-side energy efficiency programs and related benefits while recognizing that supply-side benefits are also achieved as a by-product of these demand-side benefits.

Model & Target Setting

Q. Please describe the attributes of the Model used to develop target savings and related costs to achieve savings targets.

A. The Model is a *"high-level, industry-wide model"*– i.e., it consolidates data from the electric utilities (Eversource, Liberty, Unitil and NHEC) and the natural gas utilities (Liberty Gas and Unitil Gas), and, it uses this consolidated data to project targets for each industry.[8]

[8] The Model is not designed to provide individual utility projections.

The Model is *"incremental"* – i.e., it builds out from the existing energy efficiency programs by incorporating the existing Commission policies and practices implemented over the past twenty-five years. The Model is supported in Staff schedules attached to this testimony.

The Model is *"gradual"* – i.e., it shows the incremental changes in savings targets over the short-term (2017-2019) and establishes guidepost savings targets for the long-term (2020-2026).

The Model is *"challenging"* – i.e., savings targets track with targets set by other New England states[9] and projects savings targets that surpass levels projected by New Hampshire-specific studies.[10]

The Model is *"balanced"* – i.e., it aligns interests of customers by building on cost-effective Core programs while providing cost recovery of all just, reasonable, and prudent costs, including performance incentives and lost revenues.

The Model incorporates *"broader vision"* – i.e., it not only increases savings targets from the existing Core targets but it also augments the administrative model estimated to implement the higher level of targeted savings by including the estimated costs of administrative and expert resources for an EERS advisory body, and the estimated costs for a Technical Resource Manual (TRM).

Q. What time period is covered by Staff's EERS model?

[9] Reference: Schedule JJC-8.
[10] GDS Report, January 2009 and VEIC Report November 2013.

A. The model spans a ten-year period, with an initial triennium (2017-2019) and a longer term comprising the remaining seven-year period (2020-2026).

Q. Please explain how your supporting schedules for the Model are organized and formatted.

A. The Model provides the same set of schedules with the same format for both electric and gas utilities for both Plan A and Plan B. For ease of identification, the schedules are marked "Electric" or "Gas".

Q. Please describe the overall methodology that explains how the Model develops savings, spending, costs to achieve savings, and cost effectiveness for the short-term (2017-2019) and the long-term (2020-2026).

A. With respect to savings assumptions, the model begins as a starting point with 2016 levels, as proposed in the 2016 Core Update, Then, savings targets are projected for a short-term period (2017-2019) and a long-term period (2020-2026). The savings targets in the short-term are recommended as <u>firm targets;</u> while savings targets for the long-term are recommended as <u>guideposts</u>.

In order to ensure that the Model reflects up-to-date savings and program designs, it utilizes the recently filed 2016 Core Update submitted on September 20, 2015 (Schedule JJC-1). Also, to ensure that savings goals are in a relevant range with other New England states, the Model compares the savings goals for New Hampshire with goals established in other New England States (Schedule JJC-8).

With respect to spending, the Model develops spending projections for utility costs in the initial triennium (2017-2019) based on historical data from 2014-2016. In addition, the first triennium[11] includes costs for performance incentives (PI)[12] and lost revenue (LR), and costs related to an administrative resource for the Advisory Council which is explained in the testimony of Mr. Stachow.

With respect to spending in the second triennium[13] and beyond (2020-2026), costs continue to include utility costs, PI, LR and the estimated placeholder costs for the consultant, the permanent Advisory Council and the estimated placeholder cost for the technical resource manual (TRM). The rationale for the estimated consultant and the permanent Advisory Council and the TRM are explained in the testimony of Mr. Stachow.

Q. How do EERS savings targets impact utility costs and revenues?

A. As noted above, the Model sets savings targets and then develops costs to achieve these savings targets. Schedule JJC-2 . Data from the most recent three-year period, 2014 through 2016, are used to inform the cost estimates. Estimated costs include PI and LR. With respect to LR, Schedule JJC-3 shows the derivation of this cost component.

In addition, the Model analyzes cost effectiveness. Schedule JJC-4. This methodology is followed for both electric utilities and the gas utilities for both Plan A and Plan B.

[11] The first triennium is assumed to be firm, with guidepost targets set for longer term years. New "triennium blocks" targets will be set through order one year prior to the start of the triennium.
[12] The Commission has treated performance incentives as a cost. *Electric Utility Restructuring*, Order No. 23,574 (November 1, 2000) at 4 and 27. Staff's treats lost revenue as a cost.
[13] Staff envisions that the second triennium will be filed for Commission approval, similar to the current practices of filing two-year multi-year Core filings for Commission approval.

Q. Please explain how the Model calculates savings values for Plan A and Plan B.

A. Savings assumptions are initially developed and applied consistently to the electric utilities and the natural gas utilities. With respect to electric utilities, the savings assumptions used are as follows:

- Plan A: over 10 years, this option develops estimated cumulative savings of approximately 9.74 percent of total electric kWh consumption, when measured against actual 2014 electric kWh usage. (Electric Schedule JJC-1 and JJC-1A)
- Plan B: over 10 years, this option develops estimated cumulative savings of approximately 14.5 percent of total sales, when measured against actual 2014 electric kWh usage. (Electric Schedule JJC-1 and JJC-1A)

Q. Why does the Model use actual 2014 kWh sales to measure the cumulative percentage?

A. The use of 2014 reflects the Commission's Order of Notice in this proceeding.

Q. Please explain how the Model calculates cumulative savings?

A. The model calculates cumulative savings by adding or stacking the <u>annual</u> kWh savings targets for each year, starting with 2017 and adding each succeeding year's annual kWh savings target through 2026, such that by the end of the tenth year, the <u>cumulative</u> savings targets are achieved. For instance, Electric Plan A shows a cumulative savings target for year 10 of 9.74, as a percent of 2014 actual kWh usage. To achieve this level, the Model shows gradual annual savings targets for Plan A as follows (Electric Schedule JJC-1 and JJC-1A):

- Year 2017: 10 percent (over year 2016 annual savings);
- Year 2018: 11 percent (over year 2017 annual savings);
- Year 2019: 12 percent (over year 2018 annual savings); and
- Year 2020-2026: 13 percent (year-over-year annual increases)

The same calculation is provided in the Model for Plan B. The model calculates cumulative savings by adding or stacking the <u>annual</u> kWh savings targets for each year, starting with 2017 and adding each succeeding year's annual kWh savings target through 2026, such that by the end of the tenth year, the <u>cumulative</u> savings target of 14.5 percent of actual 2014 electric kWh usage is achieved. (Electric Schedule JJC-1 and JJC-1A). To achieve this level, the Model shows gradual annual savings targets for Plan B as follows: (Electric Schedule JJC-1 and JJC-1A):

- Year 2017: 15 percent (over year 2016 annual savings);
- Year 2018: 18 percent (over year 2017 annual savings);
- Year 2019: 20 percent (over year 2018 annual savings); and
- Year 2020-2026: 20 percent (year-over-year annual increases).

By the end of the tenth year, as noted above, cumulative kWh savings are approximately 14.5 percent of 2014 actual kWh usage (Electric Schedule JJC-1 and JJC-1A)

Q. Is the same approach used for the Gas Utilities?

A. Yes. For instance, for Plan A, the Model calculates cumulative MMBtu savings by adding or stacking the annual MMBtu savings targets for each year, starting with 2017 and adding each succeeding year's annual MMBtu savings target through 2026, such that by the end of the tenth year, the cumulative MMBtu savings targets of 10.2 percent of actual 2014 natural gas MMBtu usage is achieved (Schedule JJC-1A). To achieve this level, the Model shows gradual annual increases in year-over-year savings targets as follows:

- Year 2017: 7 percent (over year 2016 annual savings);
- Year 2018: 8 percent (over year 2017 annual savings);
- Year 2019: 9 percent (over year 2018 annual savings); and
- Year 2020-2026: 10 percent (year-over-year annual increases).

By the end of the tenth year, as noted above, cumulative MMBtu savings are approximately 10.2 percent of 2014 actual natural gas MMBtu usage (Gas Schedule JJC 1 and 1A). Annual year-over-year percentage increases for gas savings targets is lower than the annual year-over-year percentage increases for electric savings targets. These lower percentages are due to the fact that the gas utilities have reached a higher level of savings historically (relative to the actual 2014 MMBtu usage baseline). (Gas Schedule JJC-1 and JJC 1A)

The same calculation is provided in the Model for Plan B. The Model calculates cumulative MMBtu savings by adding or stacking the annual MMBtu savings targets for each year, starting with 2017 and adding each succeeding year's annual MMBtu savings target through 2026, such that by the end of the tenth year, the cumulative MMBtu savings targets of 14.0% of actual 2014 natural gas MMBtu usage is achieved. (Gas Schedule JJC-1 and JJC-1A). To achieve this level, the Model shows gradual annual MMBtu savings targets as follows:

- Year 2017: 13 percent (over year 2016 annual savings);
- Year 2018: 14 percent (over year 2017 annual savings);
- Year 2019: 15 percent (over year 2018 annual savings); and
- Year 2020-2026: 15 percent (year-over-year annual increases).

By the end of the tenth year, as noted above, cumulative MMBtu savings are approximately 14.0 percent of 2014 actual natural gas MMBtu usage (Gas Schedule JJC-1 and JJC-1A).

Q. With respect to spending, how does the Model calculate the annual utility funding that is required to achieve the annual levels of target savings?

A. The Model calculates funding needed based on a number of components. Each of these components is shown on Electric and Gas Schedule JJC-2 and is summarized as follows:

Utility Spending: The Model calculates utility spending by multiplying the average unit cost by the annual saving reflected in the Model. Specifically, the Model calculates unit costs for the past three-year period (2014-2016), adjusted for inflation at 2.5 percent per year, and multiplies these unit costs by the projected annual savings.

Advisory Council Consultant: This component is new and is explained in the testimony by Mr. Stachow. The Model incorporates a placeholder amount of $100,000 for year 2017, for one full-time staff to facilitate Council meetings, engage consultants and prepare recommendations for the EERS for both electric utilities and gas utilities. Estimated amounts for subsequent years are adjusted for inflation at 2.5 percent per year. When the specific services to be provided by this administrative resource are known, Model spending can be adjusted accordingly.

Permanent Advisory Council: This component is new and is explained in the testimony by Mr. Stachow. The Model incorporates a placeholder amount of $1 million for year 2020 for both electric utilities and gas utilities, respectively. Estimated amounts for subsequent years are adjusted for inflation at 2.5 percent per year. When specific services to be provided by the permanent Advisory Council are known, Model spending can be adjusted accordingly.

Technical Resource Manual (TRM): This component is new and is explained in the testimony by Mr. Stachow. The Model incorporates a placeholder amount of $500,000 for year 2020 for both electric and gas utilities. For subsequent years, the Model provides a placeholder amount of $250,000 per year for annual updates to the TRM. Estimated amounts for annual updates of the TRM are adjusted for inflation at 2.5 percent per year. When more information about the introduction of the TRM is known, the Model spending can be adjusted accordingly.

Performance Incentives: The Model calculates this component by multiplying utility spending by 10 percent. The utility spending is separate from the new components (i.e., Consultant for the Permanent Advisory Council or the Permanent Advisory Council or the TRM). The 10 percent cap applies to both electric utilities and gas utilities.[14]

Lost Revenue (LR): The Model calculates this component by estimating the cumulated volume of kWh and MMBtu sales that are foregone by the energy efficiency savings associated with the EERS.[15] These cumulated kWh and MMBtu volumes are multiplied by an estimate unit fixed costs.[16] The resulting calculation represents the estimated amount of LR.

RGGI and ISO-NE Forward Capacity Market (FCM): The Model reduces the required SBC funding for EERS by a placeholder amount of $5 million per year. The placeholder amount pertains to funding from RGGI which is estimated at $2.5 million annually based on current legislation which provides the first $1 of allowance proceeds for energy efficiency programs; and, the SBC funding for EERS is also reduced by estimated placeholder amount of funding from ISO-NE (FCM) of $2.5 million per year. When more information is known about these revenue sources, the Model spending can be adjusted accordingly.

The Model identifies each component and summarizes the above amounts for purposes of calculating the required SBC and LDAC rates to achieve the savings targets in the EERS (Schedule JJC-2).

[14] The baseline assumed by the Model is consistent with the currently approved baseline of 7.5 percent for the electric utilities. The Model applies this baseline consistently to both electric and gas utilities. The Model assumes the utilities will achieve extraordinary performance and earn up to the cap of 10 percent.

[15] The lost revenue calculation reflects only "pure" kWh savings – i.e., does not include non-electric thermal savings converted to kWh savings.

[16] See Attachment 2, Schedule JJC-3 which shows estimated unit fixed costs.

Q. Please explain how the Model calculates SBC and LDAC rates.

A. The Model calculates SBC and LDAC rates by dividing the spending as summarized above (less the ISO-NE FCM and RGGI) by the estimated kWh and MMBtu sales projections.[17] See Schedule JJC-2 for both electric utilities and gas utilities for both Plan A and Plan B.

Q. With respect to performance incentives (PI) and lost revenue (LR), how does the Model calculate these amounts?

A. The model accounts for these values as "costs" and includes them in the costs (denominator) for purposes of calculating the Benefit /Cost test. Schedules JJC-2 summarizes all cost components, with additional detail on the derivation of the LR component provided in Schedule JJC-3. Schedule JJC-4 summarizes the benefit/cost ratios. For ease of identification, the schedules are marked either "Gas" or "Electric".

Q. How are the amounts for PI and LR calculated?

A. With respect to PI, it continues to be calculated for both electric and gas utilities on a before tax basis – i.e., PI is not grossed-up for taxes which is consistent with current PI formulation used by the Commission.[18]

[17] For electric utilities, the Model uses 2016 kWh sales, as reflected in the 2016 Core Update, for the 10-year period 2017-2026. This assumption is based on the observation that 2013 and 2014 actual kWh sales show very little year-to-year change. For gas utilities, the Model increases annual MMBtu sales by 2.5 percent per year, starting with year 2014. This assumption is conservative (low) based on the observation that 2014 MMBtu sales are almost 6 percent higher than 2013 MMBtu sales.

[18] Order No. 20,359, December 31, 1991.

Also, PI is calculated for both electric and gas utilities in the same way – i.e., it incorporates a cap of ten percent.[19] The current cap for gas utilities is 12 percent; but, the Model assumes a reduction to 10 percent, consistent with the cap for electric utilities.

With respect to gas utilities, the Model uses the same PI cap as electric utilities to ensure consistency – i.e., given consistent Core programs delivered across the State, parity in incentives for gas and electric programs is appropriate. Also, 10 percent PI represents the highest PI percentage in New England – i.e., the next highest PI allowed for gas utilities in New England is 8 percent, the cap for Connecticut gas utilities.[20] In addition, 10 percent appears appropriate since it incents New Hampshire gas utilities to continue to achieve extraordinary performance – i.e., in 2014, the gas utilities achieved actual MMBtu savings that were greater than planned savings while spending less than approved budgets.

Q. Please explain how the Model calculates LR.

A. The Model calculates LR on a before tax basis – i.e., LR is not grossed-up for taxes, consistent with the current formulation used by the Commission for PI.

Also, LR is calculated for both electric and gas utilities in the same way – i.e., by multiplying cumulative kWh and MMBtu savings by estimated retail rates per kWh and MMBtu. This methodology is a "targeted" approach to decoupling. *See Energy Efficiency Rate Mechanisms*, Order No. 24,934 (January 16, 2009) at 21 (revenue

[19] The Model uses the same cap for calculating PI for Electric Utilities and Gas Utilities. For purposes of projecting costs, the Model assumes that the utilities will achieve the 10 percent cap; thus, the Model includes PI at that cap level in the costs.

[20] Connecticut Public Utilities Regulatory Authority, Docket No. 13-03-02 Compliance Filing, February 28, 2014.

decoupling rate reconciling adjustment mechanisms "pertain only to specific sales volume reductions, such as volume reductions associated with the implementation of energy efficiency programs"). Staff's model provides a cap of 0.25 percent for Plan A. The cap is increased to 0.50 percent for Plan B, recognizing the increase in savings that is projected in Plan B (as compared to Plan A).

Q. Please provide more details of the LR mechanism used in the Model.

A. As noted above, the Model incorporates LR using a "targeted" methodology – i.e., it pertains only to energy efficiency programs. Also, Staff's Model utilizes a "partial" mechanism – i.e., it provides for a one-year recovery up to a cap, sometimes referred to as a "hard cap" (Schedule JJC-3).

<u>Targeted</u>: The Model calculates LR based on a targeted approach that focuses only on energy efficiency programs that reduce kWh and MMBtu sales.

<u>Hard Cap:</u> Specifically, the Model shows LR for electric utilities during 2017-2019 of $920,465 for Plan A; and $1,988,618 for Plan B. For the gas utilities, the Model shows zero amount for LR during 2017-2019 for Plan A and Plan B. The Model shows that these amounts are included in costs. See Schedule JJC-3 for gas and electric utilities.

During the second triennium (2020-2022), the savings targets are guideposts and not firm; thus, when firm targets are set for this time period, the hard cap could be re-visited.

Q. Continue with your explanation of how the model calculates LR for the electric and gas utilities.

A. The Model uses the same methodology to calculate LR for both electric and gas utilities. Several adjustments are incorporated as follows:

Incremental Adjustment: This adjustment reduces targeted savings for years 2017 and beyond, and thus reduces LR accordingly. Specifically, this is a one-time adjustment that reduces 2017 calculated LR by the average level of savings that was achieved during the past three years.[21] The Model rationale for this adjustment is that LR should reflect only the incremental savings that are achieved – i.e., savings that are over and above the annual levels that were achieved in the past (without LR) (Schedule JJC-3).

Retirement Adjustment: This adjustment reduces the targeted savings for years 2017 and beyond, and thus reduces LR accordingly. Specifically, the Model assumes that as older energy efficiency installations reach the end of their useful lives, the associated savings come to an end. As a result, all other variables unchanged, the utilities revenues will increase and LR will decrease.

The Model reduces the calculated LR accordingly; however, rather than reduce LR by 100 percent due to retirements; the Model applies a discount of 50 percent. This adjustment is made to reflect conservatism and the inherent complexity of accurately determining LR.(Schedule JJC-6).

[21] The Model uses the average level of savings achieved in the past three years (2014-2016) to calculate "prior year" levels of savings.

<u>Fuel Conversions/Switching</u>: This adjustment reduces targeted savings for years 2017 and beyond, and thus reduces LR accordingly. In a significant number of gas heating and hot water installations, it appears that customers convert/switch from oil to gas; thus, gas sales volumes increase. This increase in gas sales volumes reduces the utilities' LR. Much of this conversion/switching is assumed to be associated with the installation of new high efficiency gas heating and hot water installations; thus, the Model reduces the calculated LR accordingly. (Gas Schedule JJC-6A).

Q. You mention inherent complexities of accurately determining LR. What are some of these complexities?

A. Some of the complexities in introducing and calculating LR are as follows:

- Utilities may come in for a rate case and their filing may increase customer charges. This might require an adjustment in the LR formula.

- LR could create higher bills for customers. For instance, if a C&I class has a small number of gas customers, and one customer goes out of business, the impact of LR is spread over the remaining customers in the class until the next rate case adjusts the rate class assignments of LR and other costs.

- LR accumulates over time. If a utility does not come for a rate case in a long period of time, then LR could build up. This scenario could result in funds consumed by LR rather than energy efficiency programs.

- There could be unintended shifting or risks. As noted by the Commission, revenue decoupling (i.e., including LR) may result in a shift of risk away from the utility and toward the customers. The Commission has stated that it would be appropriate to propose revenue decoupling in the context of a rate case in order to avoid single-issue ratemaking.[22]

- If LR is not carefully designed, unintended windfall profits could result – i.e., lost revenue adjustments that are over and above the utilities' operating costs.

Given the above, the Model incorporates a cautious approach to determining LR – i.e., it incorporates a "targeted" and "partial" mechanism. See Schedules JJC-3, JJC-6 for electric and gas utilities; also, Gas JJC-6A (for gas only).

Q. How does the model calculate cost-effectiveness?

A. The Model provides a calculation of cost effectiveness based on the Total Resource Cost (TRC) test that is currently used by the Commission (Schedule JJC-4). Net present value of benefits for purposes of the TRC reflects the most recent 2015 Avoided Energy Supply Cost (AESC) Report.[23]. Net present value of costs for purposes of calculating cost effectiveness include utility costs, customer costs, PI, LR, and new infrastructure spending, in net present value dollars.

Q. Please explain how benefits and costs are derived by the Model for purposes of calculating the Benefits/Cost (B/C) ratio.

A. Given that the Core programs have a fuel-neutral design, the Model incorporates the benefits associated with fossil savings into the calculation of lifetime benefits. This is

[22] Order No. 24,934 (January 16, 2009) at 21-22.
[23] TCR, Avoided Energy Supply Costs in New England: 2015 Report, March 27, 2015, revised April 3, 2015.

done based on a 3-year average (2014-2016) utilizing Eversource as a proxy.[24] For our electric utilities, the average is $0.084 per equivalent kWh. For our gas utilities, the average is $8.07 per MMBtu (Schedule JJC-7).

Costs include annual utility costs, customer costs, PI, and LR for the first triennium. In addition, for the first triennium (2017-2019), costs include the estimated costs of the consultant for the Advisory Council ($100,000 per year plus annual escalation of 2.5 percent).

For the years after the first triennium, the Model provides estimates for additional annual costs for the permanent Advisory Council ($1 million per year plus annual escalation of 2.5 percent) and the estimated cost of the technical resource manual ($500,000 for 2020, and $250,000 per year plus annual escalation of 2.5 percent for subsequent years). A discount rate of 2.5 percent is used to convert estimated costs to NPV costs[25] for purposes of calculating the benefit cost ratios.

The Model calculates the B/C ratio for both electric and gas utilities by dividing the NPV lifetime benefit dollars by the costs (Schedule JJC-4). With respect to benefit amounts, a discount rate of 1.36 percent is used to convert estimated benefits amounts to NPV benefits for purposes of calculating the B/C ratios.

[24] For purposes of this calculation, "equivalent" kWh savings are used (i.e. MMBtu are converted to kWh). Also, NPV benefits are calculated based on average 2014-2016 benefits data and used for all years.
[25] There is no discount rate applied to calculate NPV for benefits since the Model includes benefits at estimate net present value.

Q. How does the model calculate the funding that is required for the anticipated spending?

A. For the electric utilities, the Model assumes continuation of funding via the SBC, supplemented by RGGI and ISO-NE (FCM) revenues.[26] For gas utilities, the model assumes continuation of funding via the LDAC. The Model assumes that the Commission will increase the SBC and LDAC mechanism to fund the increases in spending required to support the higher levels of savings.[27] Additional funding opportunities beyond the existing SBC and the LDAC might be available to expand - funding for an EERS. Mr. Stachow and Mr. Dudley will provide more information about potential additional funding opportunities.

With respect to SBC rate mechanism, the energy efficiency component is currently fixed at $0.0018 per kWh. In order to fund the higher levels of savings for Plan A, the Model shows an SBC rate per kWh in the range of to $0.0020 per kWh to $0.0092 per kWh; and, for Plan B, the Model shows an SBC rate per kWh in the range of $0.0022 per kWh to $0.0170 per kWh.[28] For Plan A, the Model shows a spending shortfall, from existing funding, in range of $2.7 million to $81.4 million; and, for Plan B, the Model shows a spending shortfall, from existing funding, in the range of $4.0 million to $167.3 million for Plan B (Electric Schedule JJC-2).

[26] The Model augments SBC funding by an estimate of $2.5 million for RGGI and $2.5 million for ISO-NE (FCM).
[27] Staff recognizes that the Commission has broad ratemaking authority and can use other mechanisms besides the SBC and LDAC or methods besides a surcharge. A discussion of different types of cost-recovery vehicles is included later in the Staff's testimony.
[28] SBC rate changes are projected to increase due primarily to cost to achieve increasing levels of kWh savings along with annual escalation of 2.5 percent per year, coupled with the assumption that electric kWh sales <u>remain unchanged</u> during the projection period.

With respect to the LDAC, the energy efficiency component of the LDAC is currently $0.0291 per therm.[29] In order to fund the higher levels of savings for Plan A, the Model shows an LDAC rate in the range of $0.0324 per therm to $0.0791 per therm; and, for Plan B, the Model shows an LDAC rate per therm in the range of $0.034 per therm to $0.124 per therm.[30] For Plan A, the Model shows a spending shortfall, from existing funding, in the range of $1.1 million to $18.9 million for Plan A; and, for Plan B, the Model shows an annual spending shortfall, from existing funding, in the range of $1.6 million to $33.9 million (Gas Schedule JJC-2). The Model assumes that shortfall will be covered by an increase in the LDAC.

Q. **For electric utilities as a whole, what is the estimated monthly bill impact for a residential customer?**

A. For Plan A, based on assumed residential monthly usage of 700 kWh per month, the Model calculates an estimated residential monthly bill impact to cover the shortfall in the existing SBC of between $0.17 per month to $5.18 per month. For Plan B, the Model calculates an estimated monthly residential bill impact to cover the shortfall in the existing SBC of between $0.25 and $10.68 per kWh (Electric Schedule JJC-2).

[29] This LDAC rate is based on a composite of the overall Residential and C&I rate for Energy North and Northern for years 2014-2016.

[30] LDAC rate changes are projected to increase due primarily to increased costs to achieve higher levels of MMBtu savings along with annual escalation of 2.5 percent per year, partially offset by estimated increases in gas MMBtu sales of 2.5 percent per year.

Q. For electric utilities as a whole, what is the estimated monthly bill impact for a C&I customer?

A. For Plan A, based on an assumed C&I monthly usage of 7,000 kWh per month, the Model calculates an estimated C&I monthly bill impact to cover the shortfall in the existing SBC of between $1.74 per month to $51.83 per month. For Plan B, the Model calculates an estimated C&I monthly bill impact to cover the shortfall of between $2.53 and $106.57 per month (Electric Schedule JJC-2).

Q. For Gas utilities as a whole, what is the estimated monthly bill impact for a residential and C&I customer.

A. The Model does not determine the estimated residential and C&I monthly bill impacts. LDAC rates are differentiated (1) by individual utility and (2) by residential and C&I rate class. The Model design does not address this level of detail. However, the Model shows an industry-wide estimate of bill impacts. Specifically, for Plan A, the Model shows that the industry-wide LDAC rates need to increase from the existing rate of $0.0291 per therm to a range of $0.0324 to $0.0791 per therm to cover the shortfall for the years 2017 and 2026 respectively. For Plan B, the Model shows that the industry-wide LDAC rates need to increase from the existing rate of $0.0291 per therm to a range of $0.034 per therm to $0.124 per therm for years 2017 and 2026 respectively (Gas Schedule JJC-2).

Q. What is Staff's target recommendation based on this analysis?

A. Staff has reviewed the energy efficiency market potential studies prepared by VEIC and GDS as well as the EERS targets adopted by neighboring New England states and those who have adopted EERS in a more gradual fashion as exemplified by the Mid-Western

States. On the one hand Staff understand that potential studies, while providing a suitable road map, do assume targets based on all potential measures being deployed. On the other hand, comparison with neighboring states entails the risk that states do differ. Staff has opted for a three-year fixed target time horizon with a 'guidepost' target for the period up to 10 years. The 'guidepost' for the remaining 7- year period to be reviewed and updated in light of the initial experience and performance achieved during the first three year cycle. Staff have proposed two sets of targets: Plan A and Plan B. Plan A mirrors the EERS Straw Proposal and reflects a less aggressive strategy, while Plan B adopts a more ambitious approach. In either case additional public funding will be required and all other funding, incentives, and lost revenue adjustment conditions remain in common.

Targets levels presuppose that utilities will be able to benefit over time from both supply side and demand side efficiency measures.

The targets are as follows and are to apply to all investor owned utilities.

Table 4. Three-Year and Ten-Year Targets

	3-year fixed cumulative savings target, Electric	10-year notional cumulative savings target, Electric	3-year fixed cumulative savings target Gas	10-year notional cumulative savings target, Gas
Plan A	1.82%	9.74%	2.14%	10.20%
Plan B	2.04%	14.48%	2.39%	13.96%

Based on the potential study and the successes of neighboring states, and assuming adequate funding, Staff believes that the savings levels projected for Plan B are reasonable and achievable, and Staff recommends that the Commission adopt them. Staff's recommendation is based on the understanding that as the targets ramp up, program savings will be continue to be reflective of a number of adjustments and actions including:

(1) updated input savings assumptions associated with EM&V impact studies,

(2) updated designs associated with customer preferences as identified in EM&V process studies,

(3) market changes associated with customer behavior such as those identified in Home Energy Reports (HER) programs,

(4) market transformation initiatives such as third-party financing options that increase the participating customer share of the energy efficiency programs,

(5) reductions in rebates due to price reductions for energy efficiency products,

(6) innovative programs including the Customer Engagement Platform (CEP) and the HER program,

(7) the expertise and commitment of the utilities to deliver energy efficiency programs to customers,

(8) continued funding through the existing SBC and LDAC mechanisms, including continued utility rewards via PI and additional earnings associated with targeted LR. Staff believes the portfolio of energy efficiency programs will continue to evolve and will likely achieve the savings levels projected in Plan B.

Q. What other ways will target metrics be presented?

A. Using the example of Plan B electric EERS, Staff proposes that target metrics will be tracked and expressed as follows:

Table 5. Electric Savings Plan B

Year	Percentage year to year KWh savings increase	Annual savings: KWH	Annual savings: Percentage of 2014 kWh sales	Cumulative savings: kWh	Cumulative savings: Percentage of 2014 kWh sales	Annual equivalent kWh savings	Lifetime equivalent kWh savings
2017	15.00%	61,050,771	0.57%	61,050,771	0.57%	78,980,998	1,129,113,405
2018	18.00%	72,039,910	0.67%	133,090,681	1.24%	93,197,577	1,332,353,818
2019	20.00%	86,447,892	0.80	219,538,573	2.04%	111,837,093	1,598,824,582

While it is intended for the savings targets to be mandatory for the first triennium (2017-2019), budget flexibility (i.e., such as continuation of program budget transfers within residential and C&I sectors), and cost controls (i.e., such as continuation of 5 percent cap on annual spending as compared to approved budgets for purposes of calculating PI) form part of Staff's recommendation. Staff have assumed that given the three year mandatory target recommendation, that there should be flexibility within those three years as to how each utility attains its three-year target. If the target for a given year is not reached, Staff assumes that any shortfall may be made up in the two following years, within the budget dollars approved for the three years (2017-2019).

Similarly, Staff assumes that while the savings targets will remain a compliance obligation, a cap should be imposed on the cost associated with LR. Staff believes that a 0.5 percent, as a percent of sales revenue, is an appropriate cap. The Model indicates that, with the application of the 0.5 percent cap, the cost for LR is well within the cap during the first triennium. Given the inherent complexity in calculating LR, Staff is open to re-visiting the calculation of LR for the second triennium.

Recognizing that not all customers will take equal advantage and benefit equally from energy efficiency programs, Staff assumes that within a customer group all customer's rates will be equally affected by energy efficiency program costs. To limit the potential for cross subsidization between groups, Staff will recommend that where possible the relative investment in energy efficiency for each group should not deviate significantly from the relative sales associated with a given customer sector.[31]

G. PROGRAM FUNDING REQUIREMENTS

<u>Current Funding</u>

Q. How are the current Core programs funded?

A. The Core Electric Programs are funded through three main sources: 1) a portion of the System Benefits Charge (SBC) which is applied to the electric bills of all customers receiving delivery service through one of the NH Electric Utilities; 2) a portion of the Regional Greenhouse Gas Initiative (RGGI) auction proceeds subject to certain conditions; and 3) proceeds obtained by each of the NH Electric Utilities from ISO-NE for participation in ISO-NE's Forward Capacity Market (FCM). In addition, any unspent funds from prior program years

[31] Note that Order No. 23, 172 states: "the relative investment in energy efficiency among various customer groups should not deviate excessively from the relative electricity sales to the various customer sectors."

are carried forward to future years, including interest at the prime rate. A brief description of each funding source follows:[32]

- System Benefits Charge: The SBC is collected through a surcharge on utility customer bills at a rate of $0.0018 cents per kWh. Revenue from the SBC is divided between the regulated energy efficiency programs and an Electric Assistance Program (EAP), which helps low income customers pay their electric bills. The SBC is one of six itemized charges on a typical New Hampshire electric ratepayer's utility bill. The other charges are for delivery, customer service, stranded cost recovery, the energy itself, and an electricity consumption tax.

- Regional Greenhouse Gas Initiative: New Hampshire participates in the Regional Greenhouse Gas Initiative (RGGI), proceeds from which are allocated to the NH Electric Utilities for funding the Core Home Energy Assistance Program and municipal and local government energy efficiency projects, including projects by local governments that have their own municipal utilities.

ISO-NE's Forward Capacity Market: The Core programs also receive revenue from the regulated utilities' participation in the ISO New England Forward Capacity Market (FCM). Customers who participate in the NH Core Electric Programs agree to forego any associated ISO-NE qualifying capacity payments

[32] *See* 2016 New Hampshire Statewide Core Energy Efficiency Plan at 1-2.

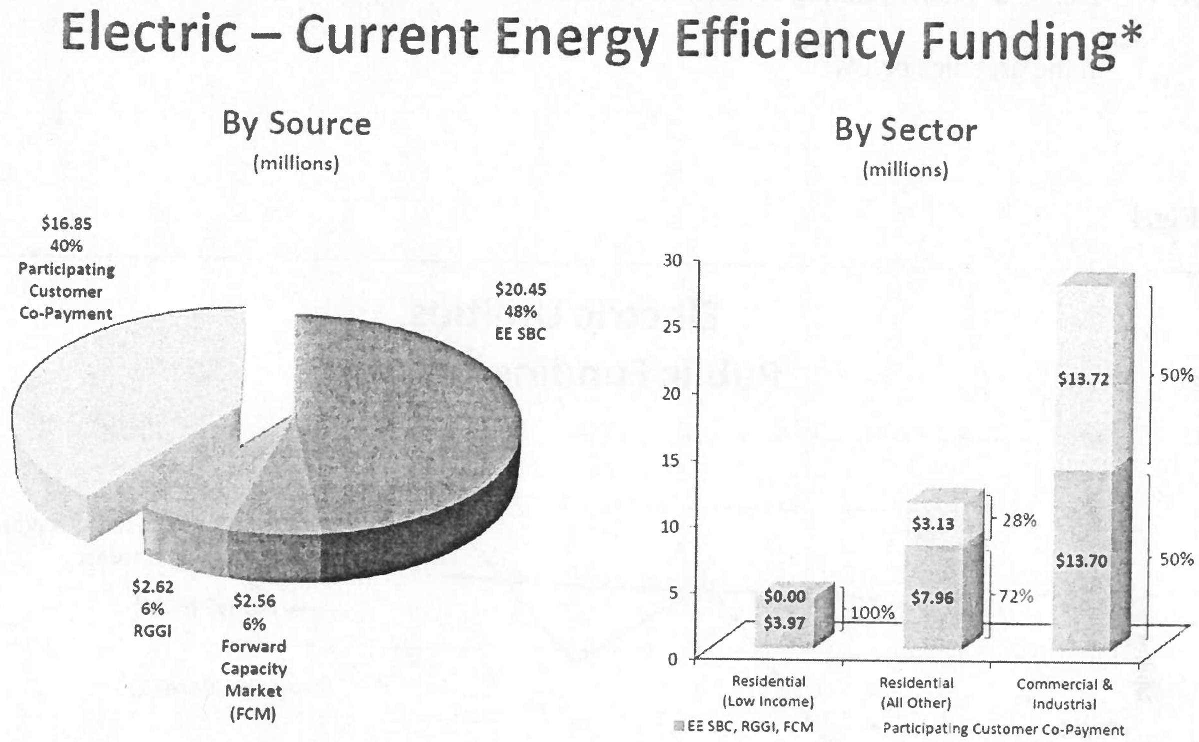
> and allow their electric utility to report demand savings and collect the capacity payments on behalf of all customers.
>
> All ISO-NE capacity payments from demand reductions resulting from the energy efficiency programs are used to support the NH Core Electric Programs and provide additional energy efficiency opportunities to NH's residents, businesses, and municipalities.

The Core Gas Energy Efficiency Programs are funded by a portion of the Local Distribution Adjustment Charge (LDAC), which is applied to the gas bills of all customers receiving service through one of the NH Gas Utilities. Similar to the electric programs, any unspent funds from prior program years are carried forward to future years, including interest earned at the prime rate.

Current levels of program funding are depicted in the graphics below:[33]

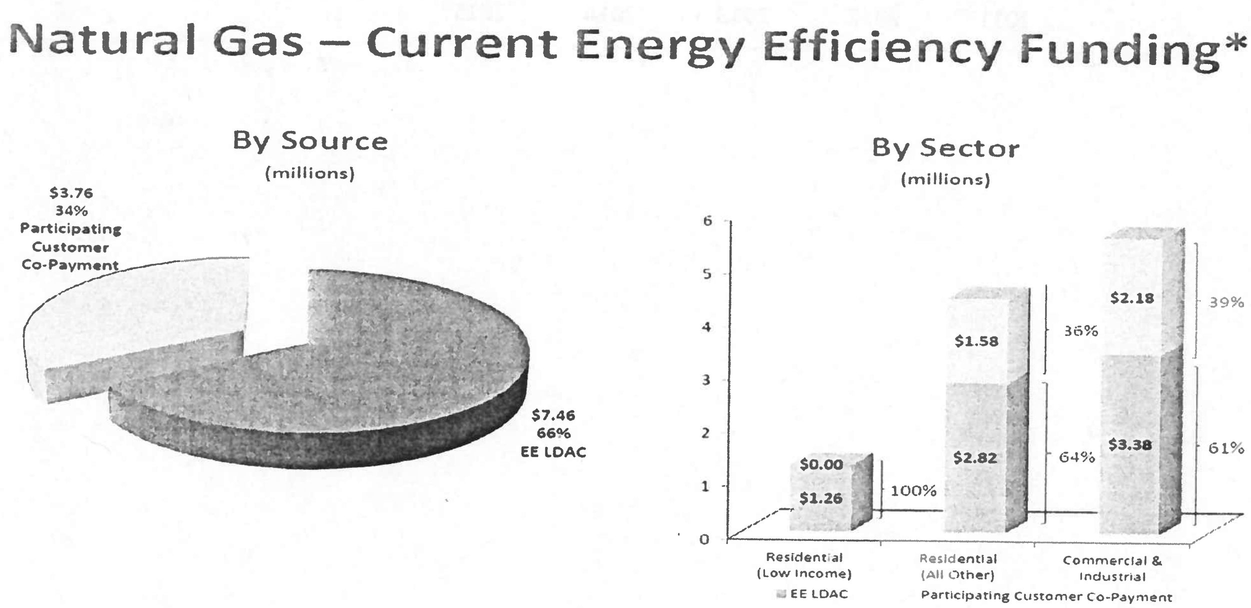
[33]Source: Core Utilities Presentation 8/21/15 at 3-4.

Fig.2



*Based on 2015 - 2016 New Hampshire Statewide Core Energy Efficiency Plan.

Fig. 3

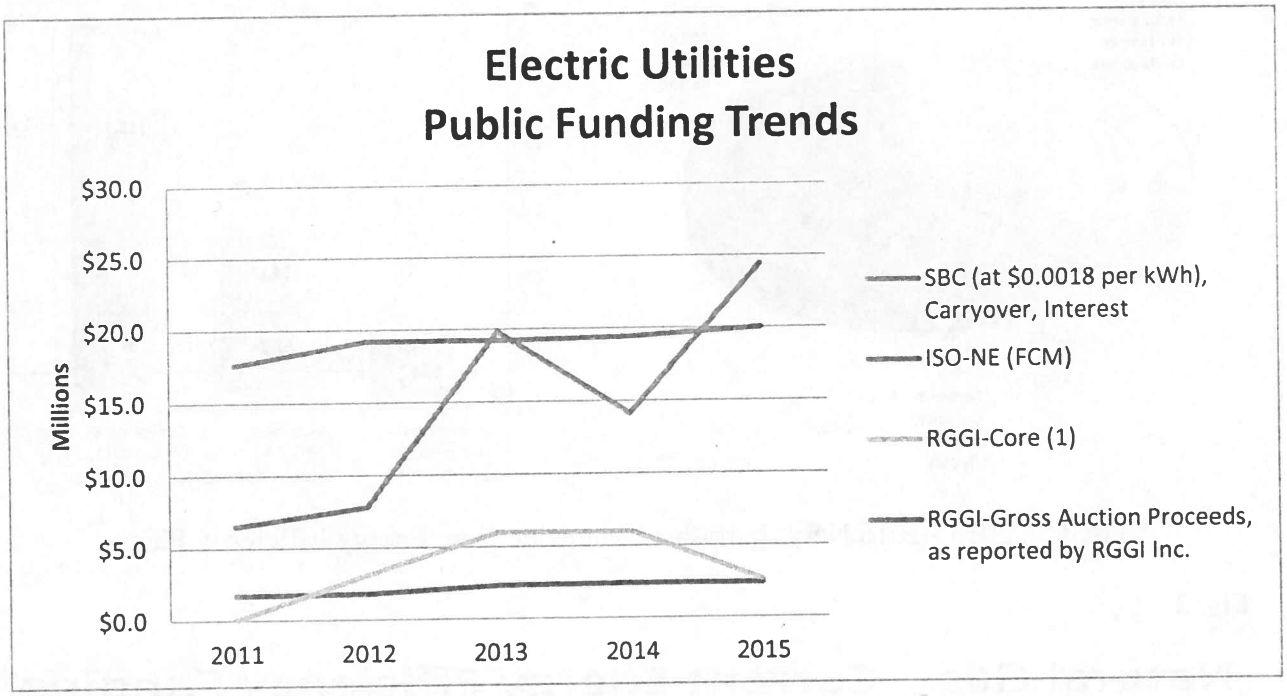


* Based on 2015 - 2016 New Hampshire Statewide Core Energy Efficiency Plan.

Q. What trends can be identified in NH EE Funding?

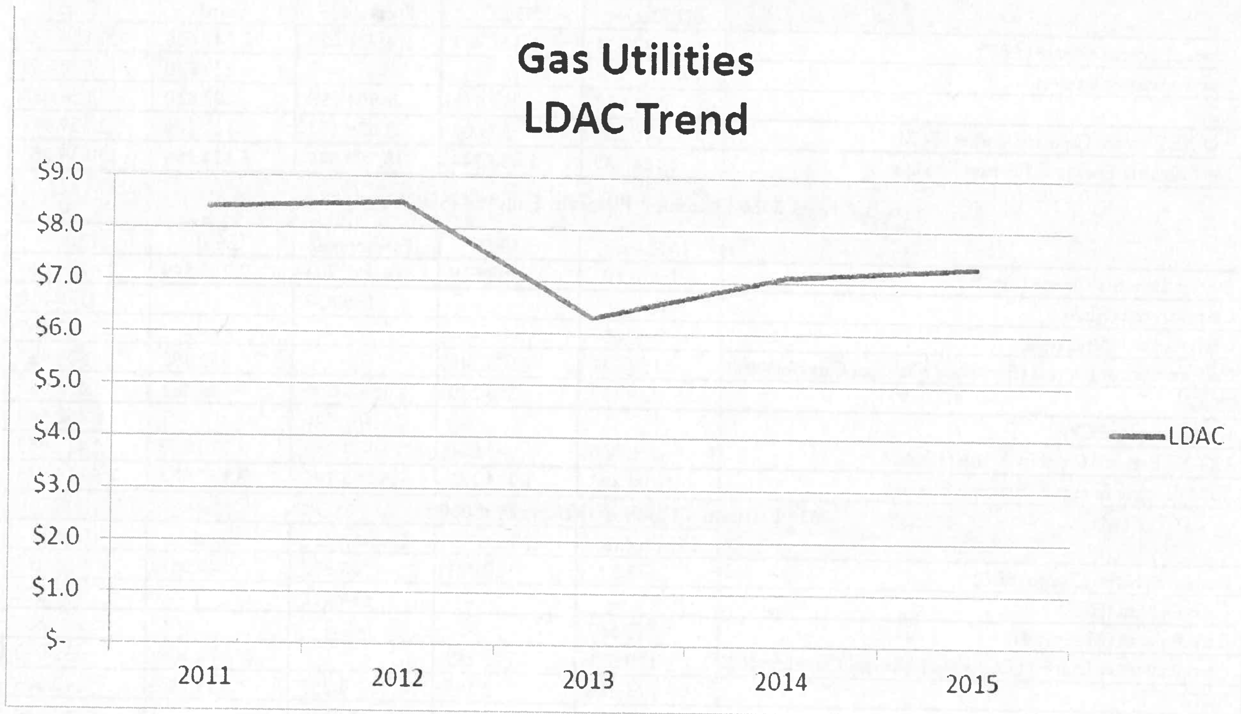
A. Trends in public funding levels since 2011 for both electric and gas utilities are depicted in the graphics below:[34]

Fig.4



[34] Source: Staff Presentation – Funding Trends, EERS Technical Session 8/21/15.

Fig.5



Q. **What are the current estimates for NH EE Funding levels for 2016 under Core?**

A. The table below summarizes the estimated program funding for 2016 for each electric utility according to funding type:[35]

[35] *See* 2016 New Hampshire Statewide Core Energy Efficiency Plan at 2.

Table 6.

Electric Programs Original 2016 Estimated Program Funding ($000's)	LU-Electric	NHEC	Eversource	Unitil	Total
System Benefits Charge (SBC)	1,787.924	1,427.709	14,721.080	2,247.618	20,184.331
Carryforward & Interest	-	-	-	270.860	270.860
RGGI	222.024	203.635	1,904.598	292.830	2,623.088
ISO-NE Forward Capacity Market (FCM)	115.000	55.000	2,075.171	312.800	2,557.971
Total Electric Energy Efficiency Funding	2,124.949	1,686.344	18,700.849	3,124.108	25,636.250

Updated 2016 Estimated Program Funding ($000's)	LU-Electric	NHEC	Eversource	Unitil	Total
System Benefits Charge (SBC)	1,714.102	1,398.688	14,462.705	2,203.549	19,779.044
Carryforward (HEA)	-	-	136.818	-	136.818
Carryforward (Municipal)	(2.667)	-	-	-	(2.667)
Carryforward & Interest (Excluding Muncipal Carryforward)	150.321	103.249	-	352.362	605.932
RGGI	218.739	206.230	1,908.853	289.263	2,623.085
Carryforward (CEP)	-	-	462.540	-	462.540
ISO-NE Forward Capacity Market (FCM)	210.000	65.000	1,823.283	312.800	2,411.083
Total Electric Energy Efficiency Funding	2,290.495	1,773.167	18,794.199	3,157.974	26,015.835

2016 Estimated Funding Difference ($000's)	LU-Electric	NHEC	Eversource	Unitil	Total
System Benefits Charge (SBC)	(73.822)	(29.021)	(258.375)	(44.069)	(405.287)
Carryforward (HEA)	-	-	136.818	-	136.818
Carryforward (Municipal)	(2.667)	-	-	-	(2.667)
Carryforward & Interest (Excluding Muncipal Carryforward)	150.321	103.249	-	81.502	335.072
RGGI	(3.286)	2.595	4.255	(3.567)	(0.003)
Carryforward (CEP)	-	-	462.540	-	462.540
ISO-NE Forward Capacity Market (FCM)	95.000	10.000	(251.888)	-	(146.888)
Total Electric Energy Efficiency Funding	165.546	86.823	93.350	33.866	379.585

The table below summarizes the estimated program funding for 2016 for each gas utility:[36]

Table 7.

New Hampshire Statewide CORE Energy Efficiency Programs Gas Programs Original 2016 Estimated Program Funding ($000's)			
	LU-Gas	Unitil-Gas	Total
Local Distribution Adjustment Charge (LDAC)	5.925.060	1.530.200	7.455.260
Carryforward & Interest	-	7.180	7.180
Total Gas Energy Efficiency Funding	**5,925.060**	**1,537.380**	**7.462.440**
Updated 2016 Estimated Program Funding ($000's)			
	LU-Gas	Unitil-Gas	Total
Local Distribution Adjustment Charge (LDAC)	5.925.057	1.321.604	7.246.661
Carryforward & Interest	146.503	133.854	280.357
Total Gas Energy Efficiency Funding	**6,071.560**	**1,455.459**	**7,527.019**
2016 Estimated Program Funding Difference ($000's)			
	LU-Gas	Unitil-Gas	Total
Local Distribution Adjustment Charge (LDAC)	(0.003)	(208.596)	(208.599)
Carryforward & Interest	146.503	126.674	273.177
Total Gas Energy Efficiency Funding	**146.500**	**(81.921)**	**64.579**

Q. What financing options are currently available to NH participants to augment the limited availability of public funding under Core?

[36] *Id* at 3.

A. The NH Electric Utilities currently offer on-bill financing at 0 percent interest to customers who participate in the Home Performance with ENERGY STAR (HPwES) program, through a revolving loan program subject to the availability of funds. Core program funding may be utilized for interest rate buy downs if an energy efficiency project does not meet the federal Better Buildings project guidelines or if the Better Buildings funds are fully expended (see next paragraph). Any unused Core funds budgeted for interest rate buy downs will be utilized within the Home Performance with ENERGY STAR program.[37] This financing option has been very popular in that the demand has typically outpaced return payments. In addition to not meeting the current demand, this program is not scalable should the level of energy efficiency services increase in the future. In 2014, the NH Gas Utilities piloted and now offer a financing option through local financial institutions at 2 percent interest. The results of this pilot program have been encouraging, and in 2015, the NH Electric Utilities began to offer a third party financing option through local financial institutions, which was based on the third-party financing option initiated by the gas utilities.

In 2016, the third-party financing option will continue to facilitate customers' access to capital for energy efficiency investments. All participating HPwES customers have access to a 2 percent loan for up to 7 years with a maximum loan amount of $15,000 for weatherization and an ENERGY STAR heating system replacement, if recommended by the program's energy auditor. While the NH Core Utilities determine the energy efficiency measures that qualify for the third-party financing option, the lender will

[37] *Id.* at 6-7.

process and service the loan. The lender assumes the risk if a customer defaults on its unsecured loan. Currently, there are four lenders participating in the program, they are: Granite State Credit Union, Merrimack Savings Bank, Meredith Village Savings Bank, and Northeast Credit Union.

Common features, terms, and conditions of these lending programs are as follows:[38]

- Offer unsecured third-party lender financing at 2 percent interest to customers participating in the Home Performance with ENERGY STAR program, where
    - Participating customers enter into loan agreements with lenders and make monthly payments directly to the lenders.
    - Lenders assume all risk associated with non-payment of loans.
    - The loan amount is negotiated with lenders up to the maximum of $15,000.
    - The NH Electric Utilities pay an interest buy-down amount to the financial institutions up-front. The interest buy-down amount is the difference between the negotiated interest rate with the financial institution (which will include a not to exceed value for a specified period of time) and the customer's interest rate of 2 percent. The interest buy-down amount is included with all other program expenditures in the calculation of the performance incentive.
    - Funds borrowed at the reduced interest rate must be used to pay for auditor recommended energy efficiency measures.

[38] *See* 2015 - 2016 New Hampshire Statewide Core Energy Efficiency Plan at 33.

- The existing 0 percent on-bill financing option is limited to customers with co-payment amounts less than a certain dollar threshold. Each NH Electric Utility will determine the appropriate threshold based on the demand for loans and the current and projected revolving loan fund balance. For example, PSNH's threshold has initially been set at $2,000.
- Customers with a co-payment amount less than or equal to $2,000 will be eligible for 0 percent on-bill financing while funds are available whereas all other customers will have access to third-party financing.

  In addition, this third party offering has been expanded by an agreement with the NH Community Development Finance Authority (CDFA) which will provide up to $150,000 statewide per year in 2015 and 2016 from its residential revolving loan fund created through the NH Better Buildings Program (these funds are not considered part of the Core programs and are therefore not budgeted in the annual Core Plan). The NH Better Buildings program was designed and implemented through funding from the U.S. Department of Energy and American Recovery and Reinvestment Act program. The program is administered by the NH Office of Energy and Planning (OEP) and managed by NH CDFA.
- Through funding provided by the U.S. Department of Energy's Better Buildings Neighborhood Program, the NH Better Buildings program seeks to achieve minimum energy savings of at least 15 percent through energy efficiency upgrades in residential buildings in partnership with the state's utility administered, ratepayer funded residential Home Performance with ENERGY STAR program. The NH Better Buildings program is administered by the OEP

and currently managed by the NH CDFA. It is important to note that because these programs are offered outside the utility efficiency programs, the energy saving will not be applied to the EERS targets. Four loan products are currently offered under the program:[39]

- Residential Loans (RLF): new residential lending is not currently being offered through NH CDFA but the revolving loan fund is being used to support the HPwES interest rate buy downs.
- Residential Loan Loss Reserve (LLR): 50 percent loan loss reserve funds backing residential loans for energy efficiency.
- Commercial Loans (RLF): 2 percent - 4 percent co-lending agreements for commercial energy efficiency loans with local banks and credit unions.
- Commercial Loan Loss Reserve (CLLR): 50 percent loan loss reserve funds backing commercial loans for energy efficiency.

All loan repayments and interest income accumulates in two revolving loan funds (RLF) to be utilized for funding future loans. The LLR and CLLR earn interest and are available to back additional loans once the aggregate loan principal is less than the amount of the reserve.

- Property Assessed Clean Energy (PACE): PACE is a model program being implemented nationally that provides a unique mechanism for financingbuilding energy improvements (both efficiency and renewables) and collects payment through an assessment on the property tax bill, which does not accelerate if ownership of the property changes.

[39] *Id.* Attachment C at 2.

The long term of repayment available under the program, up to 30 years in New Hampshire allows projects to be funded on a cash flow positive basis which is typically not available with shorter term financing. Initial investment or minimum investment funding from the property property owner is not required. In New Hampshire, loans under this program are privately funded and only privately owned. Commercial properties are eligible for this financing. (C-PACE). Residential properties containing less than 5 dwelling units are not eligible. New Hampshire initially enacted C-PACE legislation in 2010, and updated the statute in 2011, 2013, 2014, and 2015. In New Hampshire, a lien supporting a C-PACE assessment is junior to any existing mortages on the participating property.

For those programs involving a buy down feature, the following tables summarize the average buy down amounts, the number of loans, and the loan buy down budgets by utility and program for 2016. These amounts are included in each utility's Home Performance with ENERGYSTAR program budget:[40]

[40] *See* 2016 New Hampshire Statewide Core Energy Efficiency Plan at 7.

Natural Gas Utilities

Table 8. Liberty Utilities

Program	Average Buy Down Amount	No. of Loans	Total Buy Down Amount
HPwES	$ 545	26	$ 14,170
ENERGY STAR Products	$ 851	24	$ 20,424
Both	$ 1,163	2	$ 2,326
TOTAL		52	$ 36,920

Table 9.

Electric Utilities

Program	Average Buy Down Amount	No. of Loans	Total Buy Down Amount
Eversource	$ 400	25	$ 10,000
Liberty Utilities	$ 478	10	$ 4,780
NHEC	$ 500	16	$ 8,000
Unitil	$ -	-	$ -
TOTAL		51	$ 22,780

Q. What are the financing options currently offered by each of the NH Core Utilities?

A. As referenced above, NH Electric and Gas Utilities currently offer 0 percent on bill financing and third party financing through local financial institutions. The utility specific offerings are outlined below:[41]

- Liberty Utilities: Liberty Utilities Gas offers low-interest third-party financing to support residential natural gas customers' participation in its Home Performance with ENERGY STAR program and ENERGY STAR

[41] *See* 2015 - 2016 New Hampshire Statewide Core Energy Efficiency Plan at 49-75.

Products program so as to improve the upfront affordability for customers to install Home Performance with ENERGY STAR auditor recommended measures and/or the ENERGY STAR Products contractor recommended measures. The offering provides customers the option of participating in a 2 percent flat rate unsecured loan for the costs of measures associated with the Home Performance with ENERGY STAR program and ENERGY STAR Products program, including boilers, controls, furnaces and water heaters.

Under the program, a customer will enter into a loan agreement with the lender and make monthly payments to that entity directly. The lender assumes all the risk if a customer defaults on their unsecured loan. The maximum customer loan is $10,000 for up to 5 years. To encourage customers to perform recommended measures, the applicable interest rate for the unsecured loan is reduced through an upfront interest rate buy-down. To date, Liberty Utilities Gas has secured agreements with three financing organizations to buy down the customer's interest rate at or below a fixed rate of 6.99 percent APR, depending on the lender and the customer's credit score, to a 2 percent fixed rate loan for customers. The currently available APR is subject to change depending on adjustments to the Prime Rate. However, the loan agreements made to date stipulate that the lender's interest rate offering will not exceed the contracted rate. Liberty Utilities Gas is also seeking other lenders to participate in the program. Liberty Utilities Gas will not be earning a performance incentive from the customer loan repayments. The savings from the measures installed will be reported in the Home Performance with ENERGY STAR and ENERGY STAR Products programs. Liberty Utilities Gas will, however, include the program's expenditures as part of the performance incentive calculation consistent with the treatment of all other program costs.

In addition, Liberty Utilities Electric offers a zero-percent, On Bill Financing (OBF) revolving loan program, pursuant to a grant award from the Greenhouse Gas Emissions Reduction Fund, to its commercial, municipal, industrial and residential customers as funds are available. The offering provides customers the opportunity to install energy efficient measures with no up-front costs, and pay for them over time on their electric bills. Under the program, Liberty Utilities Electric pays all of the costs associated with the purchase and installation of the approved measures up to the incentive amount plus a loan amount not to exceed $50,000 per measure for commercial, municipal, and industrial customers and $7,500 for residential customers. The program is designed to overcome the traditional barrier for energy efficiency projects of high upfront cost.

- <u>New Hampshire Electric Cooperative Inc. (NHEC).</u>: NHEC offers The Smart Start Program which provides members with an opportunity to install energy efficient measures with no up-front costs, and pay for them over time with the savings obtained from lower energy costs. Under the program, NHEC pays all of the costs associated with the purchase and installation of the approved measures. A Smart Start Delivery Charge, calculated to be less than the monthly savings, is added to the member's monthly electric bill until all costs are repaid. The program is designed to overcome many of the traditional barriers to energy efficiency projects including: upfront cost; customer uncertainties related to achieving energy savings; customer reluctance to install measures if there is a possibility of moving from the premise before benefiting from the efficiency project; and the so-called "split incentive", where a landlord gets little return on an investment that reduces a tenant's energy costs and a tenant has no incentive to invest in their landlord's building.

NHEC also offers a zero-percent, On Bill Financing revolving loan program to its residential members as funds are available. Residential members who participate in NHEC's Home Performance with Energy Star Program are eligible to apply for interest-free loans to finance a portion of their out-of-pocket expenses for energy efficiency improvements made as part of that program. Repayment of these loans is made through a separate charge on the member's monthly electric bill. The terms of the program are summarized and included in Section V. of NHEC's Non-jurisdictional Terms and Conditions.

- Public Service Company of New Hampshire: PSNH also offers the Smart Start Program which provides PSNH's municipal customers with an opportunity to install energy saving measures with no up-front costs and to pay for them over time with the an opportunity to install energy saving measures with no up-front costs and to pay for them over time with the savings obtained from lower energy costs. Under the program, PSNH pays all of the costs associated with the purchase and installation of approved measures and the municipality reimburses the Company through charges added to the customer's regular monthly electric bill. The monthly charges are calculated to be less than or equal to the customer's estimated monthly energy savings. PSNH's Delivery Service Tariff Rate SSP outlines the requirements for service under the Smart Start program. PSNH also offers a zero-percent, On Bill Financing revolving loan program to its residential customers as funds are available, pursuant to a grant award from the Greenhouse Gas Emissions Reduction Fund,. Residential customers who participate in PSNH's Home Performance with Energy Star Program are eligible to apply for interest-free loans to finance a portion of their out-of-pocket expenses for energy efficiency improvements made as part of that program. Repayment of these loans is made through a separate charge on the customer's monthly electric bill. The terms of the program are summarized and included in PSNH's Delivery Service Tariff Rate LP.

- Unitil Gas: Unitil Gas offers low interest third party financing to support residential natural gas customers' participation in its Home Performance with ENERGY STAR program and ENERGY STAR Products program. The program provides customers the option of participating in a 2 percent flat rate unsecured loan for the costs of measures associated with the Home Performance with ENERGY STAR program and ENERGY STAR Products program, including boilers, controls, furnaces and water heaters. Under the program, a customer will enter into a loan agreement with the lender and make monthly payments to that entity directly. The lender assumes all the risk if a customer defaults on their unsecured loan. The maximum customer loan is $10,000 for up to 5 years. To encourage customers to perform recommended measures, the pilot reduces the applicable interest rate for the unsecured loan. Unitil Gas will complete an interest buy down upfront. To date, Unitil Gas has secured agreements with three financing organizations to buy down the customer's interest rate at or below a fixed rate of 6.99 percent APR, depending on the lender and the customer's credit score, to a 2 percent fixed rate loan for customers. The currently available APR is subject to change depending on adjustments to the Prime Rate. However, the loan agreements made to date stipulate that the lender's interest rate offering will not exceed the contracted rate. Unitil Gas is also seeking other lenders to participate in the pilot.

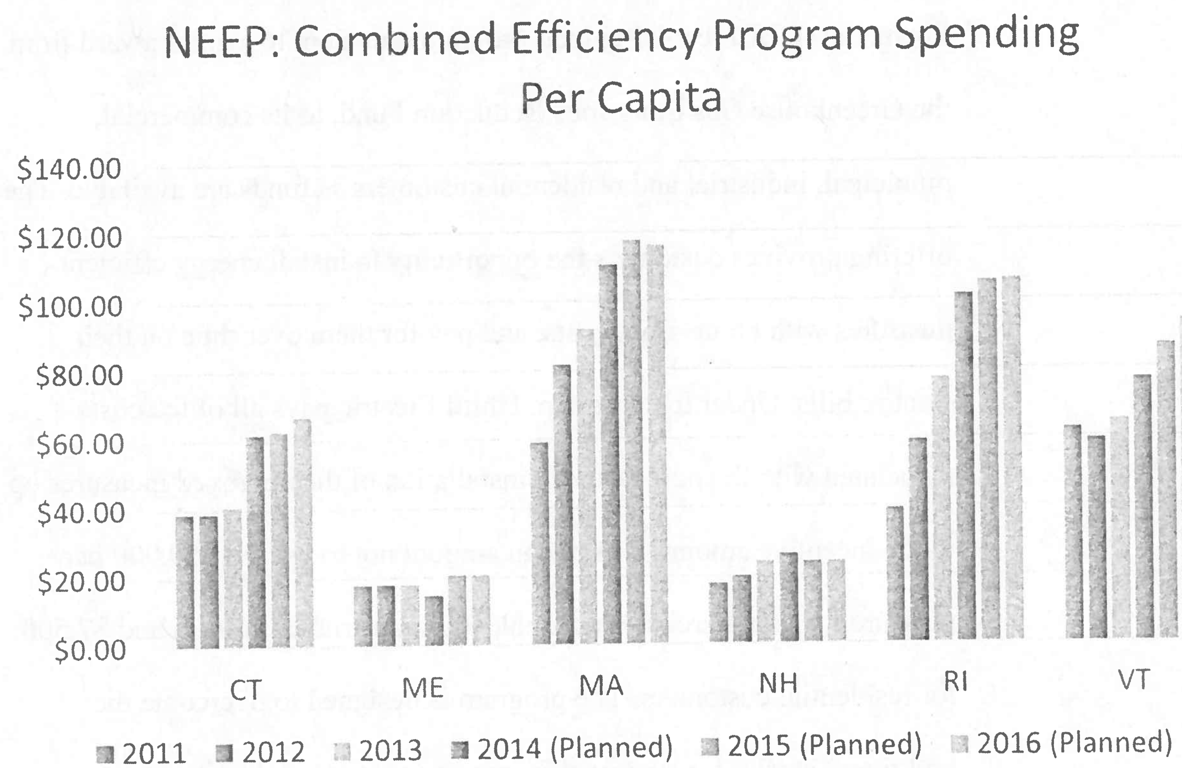
- Like the other Core Utilities, Unitil Electric offers a zero-percent, On Bill Financing (OBF) revolving loan program, pursuant to a grant award from the Greenhouse Gas Emissions Reduction Fund, to its commercial, municipal, industrial and residential customers as funds are available. The offering provides customers the opportunity to install energy efficient measures with no up-front costs, and pay for them over time on their electric bills. Under the program, Unitil Electric pays all of the costs associated with the purchase and installation of the approved measures up to the incentive amount plus a loan amount not to exceed $50,000 per measure for commercial, municipal, and industrial customers and $7,500 for residential customers. The program is designed to overcome the traditional barrier for energy efficiency projects of high upfront cost.

Comparison with neighboring states

Q. How do funding levels compare with neighboring states?

A. NEEP provided Staff and the participating stakeholders with a bar graph depicting the trends in spending/funding levels in the New England states:

Fig.6



Q. How will current funding levels meet the needs of Plan A and Plan B?

A. Because increases in future funding levels through the SBC, LDAC and RGGI are uncertain, third party financing and on bill financing will have to continue to play an important role in bridging the gap in funding to reach the desired savings targets. Financing is a critical tool for enabling energy efficiency and sustainable energy investments and can greatly augment (but not supplant) limited public funding.

The NH Core Utilities have experienced success in recent years by offering multiple financing programs across all market sectors, as described above, while also structuring programs that have attracted private capital from financial institutions which has greatly facilitated access to financing for energy efficiency projects. Accordingly, the NH Utilities will need to leverage and build upon the success of these existing programs, by considering the following enhancements:

- Continue to stimulate market demand, and thus increased loan volumes and uptake, by coordinating marketing and consumer outreach through the existing network of energy efficiency contractors and vendors utilizing a unified message on energy efficiency savings and financing options. The larger the potential loan pool, the more attractive it will be for lenders to participate.
- Continue to work with local lenders to standardize and streamline loan processing, including adoption of similar loan terms and approval criteria.
- Continue to encourage increased loan offerings to the commercial sector since it offers the largest opportunities for energy reduction savings.

In the event additional funding becomes available for the Better Buildings program, broaden the scope of the program, in conjunction with the continuation of interest rate buy downs, by leveraging its loan loss reserve to attract additional financing.

With a well-structured LLR ratio at 5 percent, as is common in other states, the New Hampshire Better Buildings program could support $80 - $100 million in loans with $4 - $5 million.[42]

Q. In addition to the above enhancements to existing programs, what other financing alternatives should the Core Utilities and stakeholders explore to increase loan volume?

A. There are currently two innovative financing mechanisms that are worth consideration:

- Warehouse for Energy Efficiency Loans (WHEEL): The Energy Programs Consortium (EPC) began the Warehouse for Energy Efficiency Loans (WHEEL) project with the Pennsylvania Treasury in 2009 after the passage of the American Recovery and Reinvestment Act (ARRA). The purpose of WHEEL is to provide low cost, large scale capital for state and local government and utility-sponsored residential energy efficiency loan programs. EPC designed WHEEL in partnership with Pennsylvania Treasury, the National Association of State Energy Officials (NASEO), Renew Financial, and Citi to provide a turnkey financing solution that can be tailored to the needs of a particular state or local government. WHEEL's objective is the establishment of a secondary market for residential clean energy loans thus providing greater volume and lower cost of capital to state and local energy loan

[42] *See* Independent Study of Energy Policy Issues, Final Report, September 30, 2011, at 10-25 and 10-26.

programs. WHEEL facilitates secondary market sales by purchasing unsecured residential energy efficiency loans originated in participating programs. The loans are aggregated into diversified pools and used to support the issuance of rated asset-backed notes sold to capital markets investors. Proceeds from these note sales will be used to recapitalize WHEEL, allowing it to continue purchasing eligible loans from state and local programs for future rounds of bond issuance. The first securitization of WHEEL loans took place in June 2015, including loans from Pennsylvania, Kentucky and Ohio. New states are joining every month. Florida has signed an agreement to join, and New York has announced its intention to join in 2015. Other states in the development stages include: Indiana, Missouri and Virginia.[43]

- Energy Efficiency Conservation Loan Program: This program is sponsored by the United States Department of Agriculture Rural Utilities Service ("RUS"). The Energy Efficiency and Conservation Loan Program (EECLP) provides loans to finance energy efficiency and conservation projects for commercial, industrial, and residential consumers. With the EECLP, eligible utilities, including existing Rural Utilities Service borrowers can borrow money tied to Treasury rates of interest and re-lend the money to develop new and diverse energy service products within their service territories. For instance, borrowers could set

[43] http://www.energyprograms.org/programs/wheel/

up on-bill financing programs whereby customers in their service territories implement energy efficiency measures behind the meter and repay the loan to the distribution utility through their electric bills. Loans under the EECLP are available to those utility systems that have direct or indirect responsibility for providing retail electric service to persons in a rural area. In general, a rural area for EECLP purposes is a town, or unincorporated area that has a population not greater than 20,000 inhabitants, and any area within a service area of a borrower for which a borrower has an outstanding loan. Eligible communities can be combined into service territories that exceed 20,000. The maximum term for loans under the EECLP is 15 years, unless the funding relates to ground-source loop investments or technology on an aggregate basis with a useful life greater than 15 years.[44]

[44] For additional information on program requirements, please see: www.rd.usda.gov/programs-services/energy-efficiency-and-conservation-loan-program .

Funding challenges

Q What are the components of cost recovery for utility energy efficiency programs?

A. There are three components to cost recovery for energy efficiency programs:

i. Program administration cost recovery (internal and external administration, rebates and services implementation services, marketing services, and EM&V);

ii. Recovery of lost revenues; and

iii. Performance Incentives.

Cost recovery is the ability of the utility to recover the just, reasonable, and prudent costs that it incurs in developing, promoting and delivering energy efficiency programs. It is critical to the success of the energy efficiency programs and just as utilities are able to recover the prudently incurred costs for generation, transmission and distribution infrastructure, they need to be able to recover their costs of energy efficiency and demand side programs.

Some states have adopted automatic adjustment mechanisms while others approach this issue on a case-by-case basis. While approaches may differ the basic elements of cost recovery include the following:

- Evaluation of prudent and reasonable program expenses eligible for recovery;
- Definition of the recovery period, and

An annual reconciliation of amounts recovered vs. actual program costs.

Q. Please explain the notion of lost revenue recovery

A. A critical barrier facing utilities when it comes to investing in energy efficiency is the negative effect it may have on their revenue stream. Under the traditional regulatory model, utilities can increase their revenues by selling more of their product. This is known as the throughput incentive: the more of a product that is sold, the more revenue a utility earns. Energy efficiency programs require utilities to invest in programs that result in decreasing sales. Thus, they are being asked to sell less of their product, and being told to invest in programs that will decrease their sales now and into the future. Thus, utilities seek a lost revenue recovery mechanism that will allow them to recapture lost revenues in light of increased modern investments in energy efficiency. Decoupling is a tool that has been adopted to address this disincentive. An effective decoupling mechanism maintains the current utility rate design while separating sales from revenues. At the end of the year, the Commission would conduct a true-up in which it compares the utility's actual revenues against its authorized revenue requirement and then adjusts rates up or down accordingly to ensure that the authorized revenue requirement is recovered.

Q. What mechanisms are available to safeguard lost utility revenues?

A. Two primary forms of lost revenue recovery exist, (1) decoupling mechanisms, and (2) lost revenue adjustment mechanisms (LRAM's).

In the case of decoupling (true –up revenue), a revenue target mechanism is put in place that permits the setting of the level of revenue to be collected during each period (including return on capital) adjusted for customer growth. Under this mechanism, a utility adjusts rates periodically in order to be able to achieve its revenue target.

Typically under the lost revenue adjustment mechanism the focus is on determining the lost revenue that can be attributed to the utility's energy efficiency programs. This is determined by measuring the actual conservation reduction in kWh's times the billing rates. The true up that follows takes place in a later period. In New Hampshire, utilities[45] have recommended a targeted LRAM in preference to a decoupling mechanism.[46]

Q. What are the potential difficulties associated with both mechanisms?

A. Under a decoupling mechanism, utility rates and revenues, established as a consequence of an approved revenue requirement are adjusted between rate cases, so that when sales deviate from rate case assumptions, the rate is adjusted to collect the calculated revenue. Thus, decoupling can provide predictable utility revenues independent of sales. Issues associated with decoupling implementation include the following:

- Requires a full rate case, *Energy Efficiency Rate Mechanisms*, Order No. 24,934 (January 16, 2009) at 21-22);
- Whether and what type of cap on rate increase should be implemented in any given year;
- Subjects rates to periodic changes;
- Postpones the need for rate cases; and
- By addressing the through-put incentive, decoupling potentially encourages greater utility energy efficiency.

[45] Core Utilities presentation, September 16, 2015

[46] The terms 'targeted' and 'comprehensive decoupling' are found in Commission Order 24,934 (January 16, 2009) at 21.

Lost revenue adjustment mechanisms measure the lost sales due to utility energy efficiency programs and provide recovery of the forgone revenues.

Issues associated with LRAM include the following:

- Measurement of lost sales attributable to energy efficiency;
- Does not address the throughput incentive;
- Requires sophisticated measurement and verification of program savings; and
- Customer impact more readily understood.

In any event, irrespective of the lost revenue recovery mechanism adopted, the following questions remain:

1. What should be the frequency of rate adjustments?
2. How should the impact on utility risk be addressed?
3. How to correct for weather-related sales adjustments?
4. What to do with earnings above or below the authorized ROE?

In terms of ratepayer impact, Pamela Morgan[47], when examining the retail rate impacts of 1,269 decoupling mechanism adjustments since 2005 found that decoupling rate adjustments are small, within plus or minus two percent of retail rates. Across the total of all utilities and rate adjustment frequencies, 64 percent of the adjustments are within plus or minus 2 percent of the retail rate, amounting to about $2.30 per month for the average electric customer and $1.40 per month for the average natural gas customer. Notably, under decoupling mechanisms, there were

[47] P. Morgan, 2012. *A Decade of Decoupling for US Energy Utilities: Rate impacts, Designs and observations.* Graceful Systems LLC.

rate decreases as well as increases. This is a difference decoupling and LRAM. LRAM's do not adjust rates down. An LRAM only increases ratepayer payments and does not decrease them.

In a recent analysis performed by ACEEE[48] in which it examined lost revenue adjustment mechanisms, ACEEE found that LRAM's are not associated with higher levels of energy savings, and that there are trade-offs between the needs of rigorous EM&V of measure savings and the desire to maintain a simple mechanism.

Q. What form of revenue recovery is Staff recommending?

A. In the short run, a lost revenue recovery adjustment mechanism may be preferable to get the EERS program implemented. An LRAM would not need a rate case as decoupling would to determine an appropriate baseline revenue requirement and allowed rate of return, however, as each utility came in for a rate case, the expectation would be that the utilities replace the temporary LRAM with a decoupling mechanism. A short-term LRAM with long-term transition to decoupling would minimize the problem of the throughput incentive and would increase the likelihood that the utilities would seek to maximize their energy efficiency and thus their savings.

[48] A. Gilleo, 2015. *A Review of Lost Revenue Adjustment Mechanisms*, ACEEE

Q. What kind of an incentive payment scheme should the Commission consider?

A. While program cost and lost revenue recovery mechanisms are intended to mitigate the utility disincentive to invest in energy efficiency, the creation of an incentive mechanism provides a signal to utilities and their stockholders that if they invest prudently in cost-effective energy efficiency programs, not only will they be made whole but they will be rewarded financially.

According to ACEEE,[49], performance incentives have been adopted by 36 states for electric utilities and by 26 states for natural gas utilities. There are several common approaches including performance target incentives, shared savings incentives, and rate-of-return incentives. The table found in Attachment 4 illustrates a range of performance incentives found in a selection of Mid-Western states, which encompass the above-mentioned approaches.

A number of analysts claim that the major advantage of incentives is that it places energy efficiency and supply side investments on a relatively equal financial footing, enabling shareholders to earn a comparable return on either investment. Critics of incentives draw attention to the cost and difficulty of implementing a robust evaluation mechanism to verify savings for performance-based incentives, as well as the perception that ratepayers should not have to pay utilities for simply complying with regulatory mandates for energy efficiency.

[49] American Council for an Energy Efficient Economy. *"The 2011 State Energy Efficiency Scorecard."* 2011

Q. What is the Staff recommendation with respect to performance incentives for the EERS in NH?

A. Performance incentives have played a vital role in promoting energy efficiency under the successful Core programs. PI's have contributed to the success of Core and are well understood by stakeholders.The current ceiling of 10 percent should be retained and be applied to both electric and gas utilities. After the first three years of the EERS program, the Commission should review the level of energy efficiency achieved, the impact of implementing a lost revenue recovery mechanism, and then determine whether an adjustment in the incentive target is required.

Q. Given the anticipated higher and growing savings targets proposed by Staff, what mechanisms are available to the Commission to increase the level of program funding?

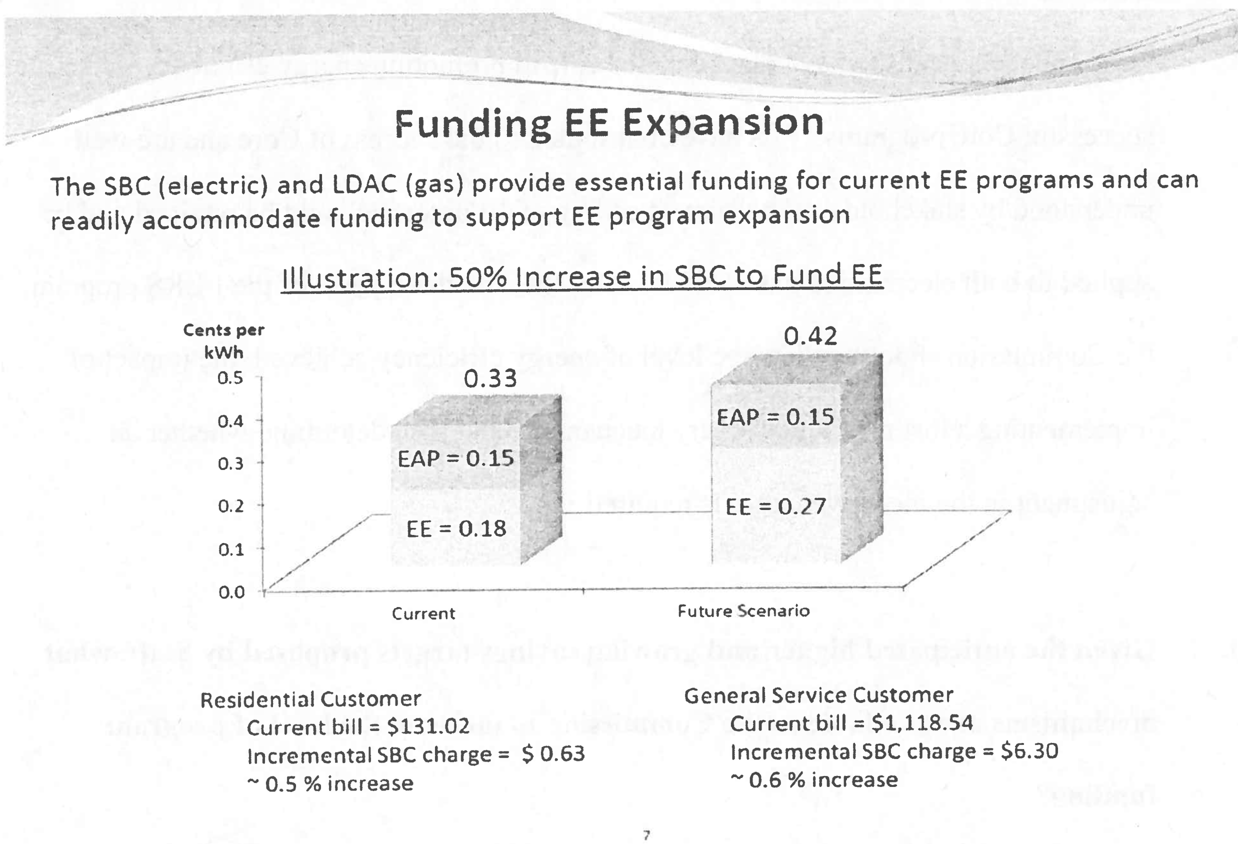
A. In the next section, Staff examines the needs for funding growth and weighs a succession of strategies that may be adopted in the future to achieve funding levels and savings objectives.

Q. What is the most immediate way that energy efficiency funding levels can be raised?

A. During the course of the technical sessions in this docket, consideration was given by the stakeholders to increasing the SBC and the LDAC to make up for shortfalls in current funding to achieve savings targets, and the corresponding rate impacts that would result. The following graph depicts a 50 percent increase in SBC funding:[50]

[50] Source: Core Utilities Presentation 9/16/15 at 7.

Fig.7



Q. How do other New England states provide for energy efficiency program cost recovery?

A. Some states, such as Massachusetts and Connecticut, have adopted stop-gap measures to ensure that shortfalls in available funding are covered. These programs are described as follows:

- The Energy Efficiency Reconciliation Factor or EERF (MA – electric only): In the event that program costs exceed other available revenue sources, a fully reconciling funding mechanism, the EERF, ensures that the costs for all available cost-effective energy efficiency measures will be funded through an adjustment to the tariff. The EERF recovers and reconciles energy efficiency costs for a particular program year with the revenue an electric utility receives through: (1) the SBC; (2) participation in the FCM; (3) proceeds from participation in cap-and-trade programs such as RGGI; (4) Loss Base Revenue, for electric utilities without an approved decoupling mechanism; and (5) proceeds available from other private or public funds that may be available for energy efficiency or demand resources. EERF estimates are calculated by allocating funds collected through the SBC, FCM, and RGGI to each customer sector in proportion to the sector's kWh consumption.

- Conservation Adjustment Mechanism or CAM (CT –electric and gas): Similar to the EERF, the CAM is used to ensure that there is sufficient funding beyond existing funding sources for energy conservation programs for both electric and gas customers in CT. This mechanism involves an annual reconciling adjustment of not more than 3 mils per kWh of electric and not more than $0.46 cents per hundred cubic feet of natural gas.

Given the success of these programs in MA and CT to smooth out gaps in public funding, and the subsequent adoption in other states such as New York, Staff recommends that the Commission should consider these mechanisms as part of the funding of an EERS.

Private sector funding

Q. Why seek out private sector funding?

A. Current estimates of the total opportunity for investment in cost effective energy efficiency in the US typically can be found in the range of several hundred billion dollars.[51] State policymakers and utility regulators are seeking to establish ever higher energy efficiency savings targets in order to address this potential. Current levels of taxpayer and utility bill payer funding for energy efficiency represents a part of the total investment needed to meet these targets, and therefore access to private capital sources is required in order to augment the funds available for investment.

Efficient access to secondary market capital is considered by a number of industry observers as one of the ways to achieve a scale of operation that would permit not only achievement of policy goals but also all cost effective energy efficiency.

A number of market observers[52] have asserted that at best private sector capital will only play a marginal role in the achievement of energy efficiency targets, however it is likely that ratcheting up current levels of public funding through reliance on SBC or LDAC charges, or alternatively seeking cost recovery of programs through an increase in rates (e.g. the Massachusetts EERF) may reach a limit leading to the attenuation of further progress.

[51] Choi Grande,H.,Creyts,J.,Derkach,A.,Farese,P.,Nyquist,S.,&Ostrowski,K. (2009) *Unlocking Energy Efficiency in the US Economy*. McKinsey & Company. Fulton M., & Brandenburg, M., (2012)*United States Building Energy Efficiency Retrofits: Market Sizing and Financing Models*. The Rockefeller Foundation and DB Climate Change Advisors.
[52] Source: Buckley, B., Technical Session on Funding, NHPUC, August 2015

Q. What is happening in the marketplace today?

A. From a growing raft of options under consideration by public administrators, some are focusing on increasing demand for high efficiency products and services to a level that will be of interest to potential investors. Others are offering products today that are designed to ensure that secondary market capital will be available and well-priced in the future. Finally a further strategy is to find ways of replenishing capital without the need for reliance of secondary markets for energy efficiency loans.[53]

Secondary market transactions may be as simple as the sale of a single loan from a primary lender to an investor or may rely on highly standardized loan products and involve the packaging of multiple loans into tradable instruments. The latter marketplace, if characterized by high volume, standardization of underlying loans, and tradable nature of secondary market instruments, may enable investors to require lower returns, or put another way, lower interest rates for primary borrowers.

Energy efficiency financing products may be divided into two broad categories, (1) specialized energy efficiency financing products and (2) traditional products. The latter make up the majority of financed energy efficiency investments today and include credit cards, home equity lines of credit, and personal unsecured loans.

[53] SEE Energy Efficiency Action Network (2015*), Accessing Secondary Markets as a Capital Source for Energy Efficiency Finance Programs: Program Design Considerations for Policymakers and Administrators.*US Department of Energy.

Specialized products possess unique features such as extended terms or the ability to pay via a utility bill and are often supported by a utility or government sponsor. Examples include PACE, program sponsored energy efficiency loans, and on bill products. At present, the secondary market is relatively immature since existing pools of capital (e.g. primary lender capital, utility or other public capital) have been adequate to meet demand in most programs. However, in some markets program administrators have begun to tap secondary markets and a number of transactions have taken place representing a total volume of $400 million.

The table following documents ten such secondary market transactions of energy efficiency loans that by 2015 have either been completed or are in progress. [54]

[54] SEE Energy Efficiency Action Network.2015.*Accessing Secondary Markets as a Capital Source for Energy Efficiency Finance Programs: Program Design Considerations for Policymakers and Administrators.*US Department of Energy

Table 10. Summary of selected energy efficiency market transactions since 2010

Transaction Short Name	Transaction Type	Issuer (Type)	Juris-diction	Date of Transaction	Market Sector	Size
Craft 3-Self-Help	Portfolio Sale	Craft 3 (Private)	OR	December 2013	Residential	$15.7M
Keystone HELP	Portfolio Sale	AFC First (Private)	PA	July 2013	Residential	$24M
NYSERDA	Revenue Bond	NYSERDA (Public)	NY	August 2013	Residential	$24M
Toledo PACE	Revenue Bond	Toledo Lucas-County Port Authority (Public)	OH	2012-2013	Commercial	$16.5M
Connecticut C-PACE	Revenue Bond	Public Finance Authority (Public)	CT	May 2014	Commercial	$30M
Delaware SEU	Revenue Bond	Delaware SEU (Quasi-public)	DE	July 2011	Public/ Institutional	$73M
HERO PACE I	Asset-Backed Security	WRCOG (Quasi-public)	CA	February 2014	Residential	$104M
HERO PACE II	Asset-Backed Security	WRCOG and SANBAG (Quasi-Public)	CA	October 2014	Residential	$129M
WHEEL	Asset-Backed Security	WHEEL SPV (Private)	Multiple (TBD)	TBD	Residential	TBD, targeting $100M
Kilowatt	Asset-Backed Security	Kilowatt (Private)	Multiple (TBD)	TBD	Residential	TBD, targeting $100M+

Q. What are the primary sources of capital?

A. It is possible to identify four main sources of capital faced by program administrators. The following table from SEE Action[55] illustrates the source, costs, size and considerations.

[55] *Id.at 3.*

Table 11. Examination of capital cost alternatives

	Cost of Capital	Size of Capital Supply	Considerations
Ratepayer/Public Funds	Low Cost Funding is flexible	Volume is limited by policy goals and willingness to invest tax/ratepayer dollars	Rate/taxpayer funds are unlikely to be sufficient to achieve all available EE; public models do not "educate" the capital market about EE assets
General Obligation Bonds or Ratepayer-Backed Bonds	Low Cost due to high ratings and authority to levy taxes or surcharges	Varies but not limitless. Bonding capacity and political will may limit capital availability	Costs are shifted onto taxpayers or ratepayers; municipal or SBC approaches do not "educate" the capital market about EE assets
Local Lender Network / Large Lenders	Moderate Cost Some flexibility, within commercial norms	Varies by number and type of lender(s)	Local lenders / large lenders flexibility and interest in EE will vary widely; this approach does not "educate" the capital market about EE assets
Secondary Markets	High all-in costs at present, may decrease over time; costs will follow credit rating	Very large potential supply, especially for investment grade securities	Secondary markets for EE are evolving and upfront costs of administration, setup and credit enhancement should be factored into decision making

At present, the Core programs rely primarily on ratepayer and public funds to implement energy efficiency objectives and targets. Secondary market transactions are relatively immature in comparison leading some observers to assert that at best private financing will represent a potential to supplement and not supplant ratepayer funded energy efficiency programming.[56]

Although the secondary market is underdeveloped at present it will be more likely to develop when:

(a) Investors become familiar with specialized energy efficiency loan products;

(b) Originators successfully create tradable energy efficiency backed instruments; and

(c) Some degree of standardization of products occurs.

[56] Source: NEEP, 2015 NHPUC Technical Session Funding.

Observers believe that when these conditions are met, lower cost capital may become available which will result in lower interest rates for customers. If in response to lower interest rates, consumer demand increases, total energy efficiency investment and savings will increase moving towards the scale objective of all cost effective energy efficiency.

Q. How should program administrators respond to this opportunity?

A. Program administrators will have a number of motivations for considering financing programs, from encouraging more projects and deeper savings to expanding access to capital for underserved customer market segments, or to incentivize new technology. Unfortunately, their objectives may not always overlap with the interests of secondary market investors. Investors will be looking for standardization on loan products, ability to assess the performance characteristics and risk reduction mechanisms.

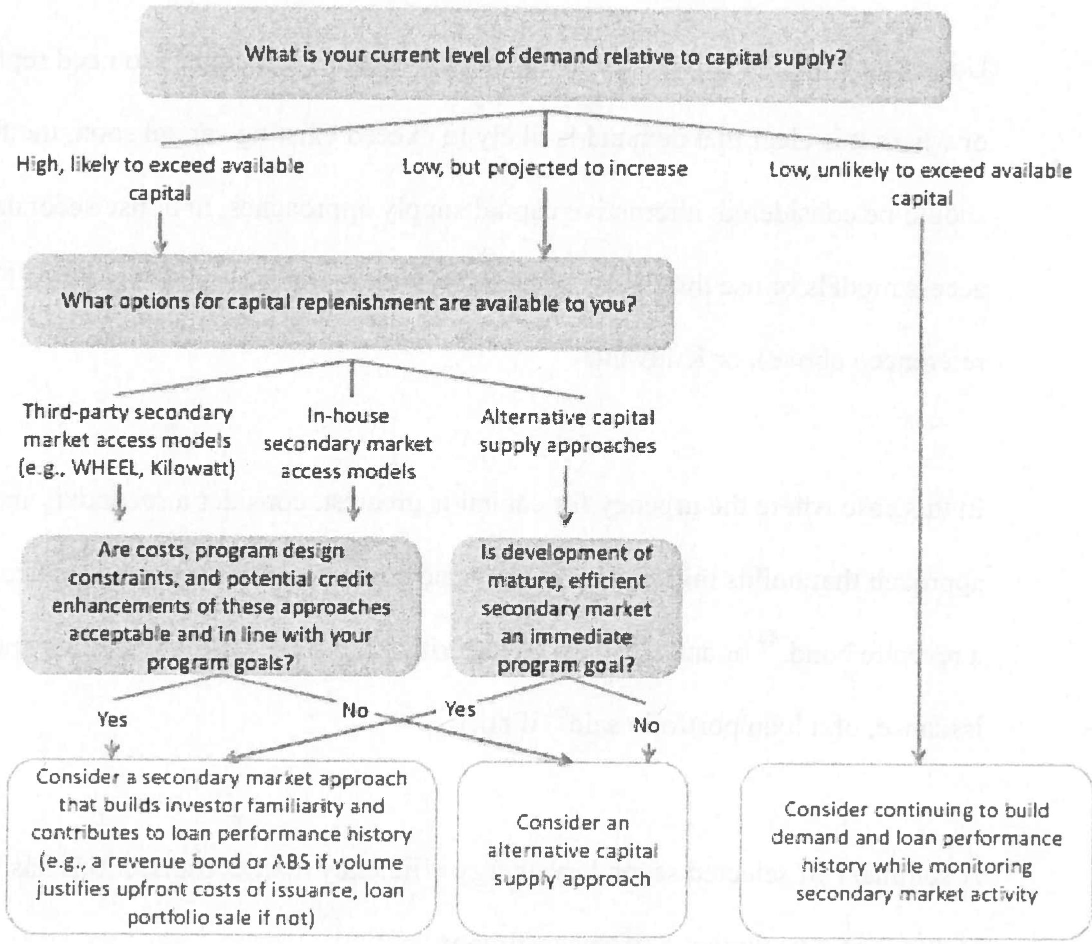
The more the basic data on risk and performance of energy efficiency products becomes available, the more investors will be willing to lower their requirements.

Program administrators should examine their existing and projected level of financing activity as well as any capital constraints. If capital is likely to become a constraining factor in program sustainability, they may choose to consider the cost benefit of utilizing secondary markets. In the initial stage this will be challenging since in the absence of experience, evolving secondary markets for energy efficiency will require higher up-front costs of administration, set up and credit enhancement. However over time as the products and their performance become well known investors are very likely to lower their administrative and interest rate expectations.

Q. What private sector financing recommendations may be offered to program administrators?

A. The SEE Energy Efficiency Action recommend that each program administrator consider their current level of energy efficiency program demand relative to capital supply. They have developed a recommended framework for considering capital supply options:

Fig.8 Frame work for examination of capital supply options.[57]



Three primary tracks are identified:

A. Low demand, unlikely to exceed available capital.

B. Low but projected to increase.

C. High likelihood to exceed available capital.

[57] SEE Energy Efficiency Action Network.2015.*Accessing Secondary Markets as a Capital Source for Energy Efficiency Finance Programs: Program Design Considerations for Policymakers and Administrators.*US Department of Energy

Under track A, the program administrator would continue with business as usual but develop a loan performance history in case of future need to turn to the secondary market in the future

Under tracks B and C, where existing capital is either anticipated to need replenishment or where it is clear that demand is likely to exceed existing capital soon, the following should be considered: alternative capital supply approaches, in house secondary market access models or use third party secondary market access models like WHEEL (as referenced above), or Kilowatt.[58]

In this case where the urgency for capital is greatest, consider a secondary market approach that builds investor familiarity and contributes to loan performance history (e.g. a revenue bond,[59] or an asset-backed securitization if the volume justifies upfront costs of issuance, or a loan portfolio sale[60] if not).

A summary of selected secondary energy efficiency market transactions has been included in Attachment 5 of this testimony.

[58] See BNY Mellon, Asset Securitization Report, June 15, 2015. Citi and Renew Financial closed the first ever asset backed security transaction comprised of unsecured consumer energy efficiency loans. The transaction resulted in issuance of $12.58 million in securities and created a new asset class in the form of ABS backed by pools of residential energy efficiency loans. The Warehouse for Energy Efficiency Loans(WHEEL) is an innovative public private partnership to create a national financing platform to bring low cost, large scale capital to government and utility sponsored residential energy efficiency loan programs

[59] Please note that in the Final Minutes of the EESE Board held at the NHPUC on September 9, 2011, Todd Sbarro, On behalf of VEIC amongst his key energy finance recommendations included the following: "Implement demand stimulation and risk mitigation mechanisms such as Qualified Energy Conservation Bonds (QECB). To date Staff understands that out of 13.6M dollars allocated to NH there may still be over $6.0 million available.

[60] Craft 3(Private).Craft 3 offers affordable and flexible financing for energy efficiency upgrades. As of June 2015, Craft 3 have helped upgrade over 3,156 homes and provided over $43.3 million of work to local energy contractors.

Q. What are the recommendations with respect to EERS funding?

A. Staff propose both a short term and long term recommendation. Based on the model analysis, within the third year of the planned EERS, assuming the Commission were to adopt the suggested targets as indicated in Plan B of the model, electric funding would experience a shortfall of $19.9 million. Under these circumstances, the model assumes that the current $0.0018 per kWh SBC rate would need to increase to $0.0036 per kWh. The anticipated monthly residential bill impact would increase from approximately $0.253 to $1.27. For the general service rate class, the monthly bill impact would increase from $2.53 to $12.70. On the gas side, at the end of the third year, the target funding would experience a shortfall of $4.9 million, and would require an increase in the LDAC from $0.034 to $0.044 per therm. Under these circumstances, Staff recommend that during the first triennium the SBC or LDAC could be adjusted annually.

Concurrently, Staff would recommend that the program administrators work with the permanent the Advisory Council to analyze the potential for greater use of private capital such that by the end of the third triennium, a plan is approved and in place to harness the role of the private sector either through loan portfolio sales or asset-backed securitization.

H. IMPLEMENTATION PROCESS

Administration

Q. What is the Staff recommendation with respect to administration of the EERS?

A. An EERS should leverage the existing Core mechanism and stakeholders in order to seamlessly move from the existing Model to the more ambitious goals of the EERS Staff has proposed. Thus, utility program administrators would conceive and plan energy efficiency programs and after review and adoption of recommendations by a stakeholder collaborative, those programs would be submitted to the Commission for approval.

Q. What role can the stakeholder play in this process?

A. Across the country, both utility-specific and statewide stakeholder collaboratives play a part in developing a consensus around a specific set of energy efficiency issues. Stakeholder participation is valuable in the development of EE policies at the state level as well as providing input at the programmatic level. The goal of the stakeholder group is to bring together a cross section of interested parties around a particular set of issues with the objective of developing a consensus for a proposed solution. The group may include utility representatives, regulators, consumer advocates, environmental groups, customers, EE program providers and consultants. Staff believe that a statewide collaborative is most beneficial to all of the participants since it will allow for better communication and sharing of information across a broad spectrum of interested parties. Utilities can learn from one another, share common challenges with regulators and other stakeholders and use the group to identify potential solutions.

Using a single collaborative body will make the most efficient use of time and resources of government agencies advocates and others involved in the stakeholder process. Finally, a statewide process allows for better reporting by ensuring that information is reported consistently across the board.

Q. What qualities should a good stakeholder collaborative entail?

A. Staff believes a stakeholder collaborative should include the following:

a. Have a broad group of knowledgeable stakeholders representing a variety of interests;

b. Activities and records open to the public;

c. Have clearly defined objectives;

d. Have regularly scheduled meetings with an agenda;

e. Have open communication and information sharing; and

f. Have consistent reporting mechanisms.

In addition, Staff believes that such a group may work more efficiently by making use of an independent facilitator and being able to draw upon the resources of an experienced external consultant.

Q. What is the Staff recommendation with respect to a stakeholder collaborative?

A. Stakeholder collaboration could be accomplished by the Commission designating the existing Energy Efficiency and Sustainable Energy (EESE) Board as its permanent EERS Advisory Council Currently, the EESE Board meets items a. through f., above. The EESE Board would continue to function independently of the Commission, and the

Commission could empower the EESE Board in its role as the EERS Advisory Council by authorizing funding for a an independent facilitator to manage the agenda, moderate discussion, and motivate consensus, and for the hiring of EE consultants as the programs require. To meet this end, the Commission would need to approve an additional administrative budget to be able to fund those positions from the existing energy efficiency funding budget.

The Advisory Council as proposed by Staff would focus primarily on EERS program design and embrace a broader mandate.

Possible roles of the Advisory Council[61] include the following:

- Responding to specific issues that arise during the design and implementation of energy efficient programs;
- Be an ongoing, reliable forum, dealing with routine and emerging issues that arise as programs mature and evolve;
- Promoting working relationships between stakeholders;
- Tackling especially complex problems, such as development of a technical manual or specific evaluation measurement and verification protocols; and
- Identifying new opportunities to create new energy efficiency programs or alter existing programs in response to market changes.

[61] SEE Action 2015. *Energy Efficiency Collaboratives*, US Department of Energy.

Q. What should be the relationship of the Commission to the Advisory Council?

A. The Commission could use the Advisory Council to educate itself and stakeholders about developing policy and best practices in the energy efficiency industry, and to make policy recommendations and identify any policy issues where there is disagreement between stakeholders, for the Commission to resolve. Staff intends the Advisory Council as a permanent resource from which the Commission's energy efficiency policy will be informed.

As SEE Action have observed,[62]

> "Customers as a group are seen as a vital and strategic demand side power sector resource with distinct advantages over other resources….new issues are emerging, driven by advanced technology, market transformation, increasing energy efficiency budgets and the desire to reach hard to reach populations such as low income households.
>
> States with energy efficiency collaboratives will find themselves better able to respond to these trends and utilize this resource."

__Possible scope of activities of the permanent Advisory Council__

Q. Please describe the possible scope of the permanent Advisory Council?

A. Staff intends the Advisory Council as a permanent resource from which the Commission's energy efficiency policy will be informed. The permanent Advisory

[62] *Id at 9*

Council would be statewide in scope,[63] be professionally facilitated have funds to engage consultants, and be empowered to make recommendations to the Commission. Due to its relatively limited budget it would rely more on peer review and input to complete tasks than on dedicated staff.

Products of the permanent Advisory Council may include the following:

- Annual report summarizing energy efficiency accomplishments in the state;
- Various studies and projects to improve deemed savings estimates, develop avoided costs or evaluate new technologies;
- Preparation of formal or informal statements of position directly to the Commission; and
- Development of a Technical Reference Manual (TRM) including evaluation measurement and verification protocols that govern a wide range of energy efficiency activities.

The permanent Advisory Council may consider the following issues in the conduct of its duties:

1. Development of collective goals;.
2. Identify all budget categories;
3. Define performance incentives;
4. Establish a EM&V framework;
5. Develop a state specific Technical Resource Manual;
6. Identify benefits and cost effectiveness of all programs;

[63] Note: Excluding municipal utilities

7. Identify key challenges and market barriers;
8. Determine the allocation of funds for low income programs and education;
9. Focus on minimizing administrative costs;
10. Address cost recovery; and
11. Identify all possible funding sources.

Q. Please describe the possible role of the Advisory Council Facilitator?

A. The Advisory Council facilitator would guide discussion, set agendas for meetings, prepare any written reports developed by the group, and maintain an Advisory Council website.

Q. Should the Commission consider a Third Party Administrator?

A. A number of states have opted to use a Third Party Administrator (TPA) to run energy efficiency programs across the state. Like utility operated programs, TPA programs are funded by ratepayers. A TPA provides a portfolio of energy efficiency programs across a state thereby creating a greater level of consistency and uniformity for all program participants. The TPA can also be used as a tool to overcome the utilities reluctance to offer energy efficiency programs to their customers. In addition the TPA can play a critical role for smaller utilities, primarily cooperatives and municipal utilities that may not have the expertise or personnel to cost effectively run energy efficiency programs. Amongst the states that have made effective use of TPA's are Vermont, Maine, New York and Wisconsin.

Staff have evaluated whether a TPA would be a useful addition to the existing utility program administrator (PA) mix and have determined that given that the PA's have effectively managed the Core programs to date and have been willing to embrace new programs, the need for an independent TPA is less clear at this time

Elements of Program Design

Q. What has been the industry standard for energy efficiency program categories and how does this typology compare with programs currently in place under Core?

A. To effectively compile and analyze information about energy efficiency programs across the country, common categorizations of program types are needed as well as definitions of the metrics that define program performance and characteristics.

As part of an effort to analyze the cost per unit of savings for utility –customer funded energy efficiency programs, Lawrence Berkley National Laboratory developed a typology of standardized categories as well as metrics and associated definitions for program characteristics, costs and impacts. The typology was developed based on interviews with 108 program administrators in 31 states for approximately 1,900 unique programs. The analysis was further informed from a variety of sources including SEE Action, Consortium for Energy Efficiency (CEE), North East Energy Efficiency Partnership's EM&V forum and the American Council for an Energy efficiency Economy (ACEEE)

Programs can be broken down into seven sectors: residential, agricultural, commercial/industrial, cross cutting and other, low income, and demand response programs.

Table 12 following seeks to document the typology at a high level while detailed tables identifying each program can be found in Attachment 6 below.

Table 12. Energy Efficiency Program Administrator Portfolio as benchmarked by LBNL[64]

Residential	Commercial	Industry & Agriculture	Commercial & Industrial	Cross Cutting & Other	Low Income	Demand Response
Behavioral/on line audit/Feedback	Audit	Audit	Custom	Codes & Standards (C&S)	Low Income	Time-of-Use Pricing.
Consumer Product Rebate/ Appliances	Custom	Custom	New Construction	Market Transformation (MT)		Critical Peak Pricing
Consumer Product Rebate/ Electronics	Commissioning/Retro-Commissioning	Custom/ Data Centers	Prescriptive	Workforce Development		Critical Peak Pricing with Load Control
Consumer Product Rebate/Lighting	Govt./Nonprofit/ MUSH	Custom/Ind. & Ag. Process	Self Direct	Marketing, Education, Outreach (ME&O)		Real-Time Pricing
Appliance Recycling	Street Lighting	Custom/ Refrigerated Warehouses	Mixed Offerings	Other		Peak Time Rebate
Multi-Family	New Construction	New Construction	Other	Planning/Evaluation/ Other Programmatic Support		
New Construction	HVAC	Prescriptive Industrial		Voltage Reduction/ Transformers		
HVAC	Lighting	Prescriptive/ Agriculture		Shading/ Cool Roofs		
Insulation; no, separate prescriptive incentives, in HEA & HP w ES	Performance Contracting/ DSM Bidding	Prescriptive/ Motors		Multi-Sector Rebates		
Pool Pump N/A	Prescriptive/IT & Office Equipment	Financing		Research		

[64] Hoffman,I., Billingsley, M., Schiller, S., Goldman, C., Stuart,E. 2013. *Energy Efficiency Program Typology and Data Metrics: Enabling Multi-State Analyses Through the Use of Common Terminology*. LBNL.

Prescriptive, No, all Via BPI auditor in HEA and HPwES	Prescriptive/ Grocery	Self Direct					
Water Heater	Other						
Windows	Custom						
Whole Home/ Direct Install	Prescriptive						
Whole Home/ Audits	Financing						
Whole Home/ Retrofit	Other						
Financing							
Other							

Using the Lawrence Berkley National Laboratory (LBNL) typology as a benchmark, Staff has compared and contrasted the NH 2016 statewide Core program descriptions[65] with the LBNL typology in order to identify a direction for EERS activity beyond existing programs that may permit a greater threshold of energy efficiency savings to take place.

Staff recognizes that at a high level of aggregation, it is difficult to compare the granular level of detailed program design, delivery, marketing and education and measures of success and market transition strategy. Nevertheless, given the comprehensive nature and descriptions provided in the LBNL typology it is possible to identify broad areas where current absence of NH action might signal a direction for the expanded EERS strategy under appropriate regulatory conditions. While these areas will be by no means exhaustive, they will identify new areas of activity that the EERS target setting may engender.

[65] *See* 2015 - 2016 New Hampshire Statewide Core Energy Efficiency Plan at 26

Areas at present addressed by the Core program are shaded in yellow, while those currently not covered by NH Core programs but addressed in other states are shaded in grey.

Findings

Analysis of NH Core funded programs relative to the LBNL benchmark is at times challenging to compare because of a difference in approach and subsequent definitions. However a number of broad conclusions may be drawn.

Residential programs.

NH Core programs largely overlap LBNL identified programs of activity. Staff could not find a pool pump program amongst the NH utilities, but in view of NH's geographical position does not consider that an issue.

Commercial & Industrial Programs

In this case we found a number of apparent omissions relative to the LBNL benchmarks.

(a) Performance contracting/DSM bidding. Although we are aware that these programs are taking place in NH, and that some energy service companies (ESCO) sell performance contracting, it is not clear to what extent they are initiated or managed by the utility program administrator.

Such programs are designed to incentivize or otherwise encourage Second participants to perform energy efficiency projects usually under an energy performance contract (EPC), a standard offer or other arrangement that involves ESCO's or customers offering a quantity of energy savings in response to a competitive bidding process with compensation linked to achieved savings.

(b) Prescriptive/IT & Office Equipment. No evidence of programs aimed directly at improving the efficiency of office equipment, primarily commercially available PC's, printers, monitors, networking devices, and mainframes not rising to the scale of a server farm or floor.

(c) Custom data centers. Data center programs are custom designed around large scale server floors or data centers that often serve high tech, banking or academia. Project tend to be site specific and involve some combination of lighting, servers, networking devices, cooling/chillers, and energy management systems software.

(d) Self direct. These are industrial programs that are designed and delivered by the participant using funds that otherwise would have been paid as ratepayer support for all DSM programs. These are often referred to as opt-out programs.

Cross cutting and other.

(f) Voltage reduction/transformers. These programs support investments in distribution system efficiency or enhance distribution system operations by reducing losses. The most common form of these programs involve the installation and use of conservation voltage regulation/reduction (CVR) systems and practices that control distribution feeder voltage so that utilization devices operate at their peak efficiency. Other measures may include installation of higher efficiency transformers by the electric distribution utility.

Demand Response.

(g) Time of use pricing. Demand side management that uses a retail rate or tariff in which customers are charged different prices for using electricity at different times during the day. Staff understand that at least one NH utility currently has such pricing in place but have been led to believe that there is limited interest on the part of customers.[66]

(h) Critical peak pricing & Critical peak pricing with load control. Demand side management that combines direct load control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices. A critical peak pricing program or such pricing combined with load control can reduce system peak substantially and address the need to invest in other expensive forms of infrastructure.

(i) Real time pricing. Demand side management that uses rate and price structure in which the retail price for electricity typically fluctuates hourly or more often to reflect changes in the wholesale price of electricity on either a day ahead or hour ahead basis.

(j)Peak time rebate. Under these conditions, customers are allowed to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days. Like critical peak pricing the number of critical peak days is usually capped for a calendar year and is linked to conditions such a system reliability concerns or very high supply prices.

Q. What are your recommendations concerning EERS program development.

[66] Any TOU rates need to be attractive to customers. In New England they are not. CA and MD amongst others have achieved high participation rates in TOU and rebate programs or pilots designed to engage and be attractive to customers.

A. In the short term, Staff expect that the Program Administrators will continue to build on the solid and successful foundation established by the Core programs. In the first triennium, assuming that funding is made available, we anticipate that efforts will be taken to dive deeper into each program in order to move towards the goal of all cost effective energy efficiency outcomes.

Concurrently we expect program administrators will begin to examine additional energy efficiency possibilities as outlined earlier.[67] Amongst those that Staff believe worthy of consideration will be the following:

(a) Performance contracting/DSM bidding;

(b) Prescriptive/IT & Office Equipment;

(c) Custom data centers;

(d) Self-directed; and

(e) Voltage reduction/transformers

In this latter case there may be a need to more effectively coordinate between the existing Least Cost Planning activities of the utilities under existing dockets and the declared objectives of an ERRS.

[67] Staff assumes that the Commission will administer the EERS programs through an adjudicative process.

Q. What other parallel policy activities are interrelated to the EERS which could lead to further program development?

A. A critical way to further expand energy efficiency possibilities is through more effective management of demand response. Today, demand response and smart grid implementation both represent emerging areas at the intersection of demand side management and technology deployment.

Demand Response

When the demand for electricity is greater than the available supply stress is placed on the entire system from the power plant through the transmission grid and the distribution system. A number of factors can contribute to this situation, including extreme weather conditions, generating facilities being off line, fallen power lines and natural disasters. Demand response programs have been designed to mitigate just such a situation. According to Federal Energy Regulatory Commission (FERC) demand response is defined as the ability of customers to respond to either a reliability trigger or a price trigger from their utility system operator, load serving entity, regional transmission organization or other demand response provider by lowering their power consumption[68]. By developing demand response policies, regulators and utilities are incentivizing customers to use less electricity at times of high energy use, thereby reducing peak energy usage and freeing up both generation and grid capacity. Utilization of demand response is poised to increase over time as the dissemination of smart meters and automated metering infrastructure increases and electric grid planners plan for more

[68] Federal Energy Regulatory Commission, *National Action Plan for Demand Response*, 2010.

utilization of demand response. Amongst the benefits of demand response programs are the following:

- Can provide a revenue stream to a participating customer;
- Relatively inexpensive action that can be captured as part of a utility resource plan;
- Considerably less expensive than purchasing power on the spot market or building peaking units that would be used infrequently;
- May help to avoid brownouts; and
- No carbon dioxide implications for the utility relative to gas peakers.
- System operators are actively seeking greater demand response to help manage system reliability

While primarily applied to residential and commercial customers, the magnitude for potential energy shifting for industrial customers is significant, and in some cases may tie in well with the states' or utilities industrial energy efficiency programs.

<u>Grid Modernization (Incorporating Advancing Technologies in a flexible regulatory system).</u>

Grid modernization and incorporation of smart grid technologies can play a major role not only in the future of energy efficiency but also putting New Hampshire's regulatory system in a position to absorb and adapt to technological and economic changes that the utility and power sector are experiencing. The major impact of this transformation will be to allow and facilitate greater consumer choice and decision making through increased information/data sharing and device control. A smart grid requires the deployment of advanced technologies that enable the movement of information between the utility and the consumer, between a utility and monitoring and control devices on its grid, between and among utility control areas, with customers and third-party service providers. Initial emphasis on the smart grid has been on the utility side of the meter, including operating the grid more efficiently, monitoring voltages and detecting outages. The promotion of demand side management, on the customers' side of the meter, and energy efficiency strategies provides opportunities for customers. Time of use rates are one mechanism to influence consumers to change their energy consumption patterns (i.e. demand response). Smart technologies can provide consumers with dynamic information on their electricity usage and corresponding costs. Coupled with time of use rates, this information can enable customers to better manage their consumption and lower their energy bills. It also enables utility customer's greater choice in products, costs and services they choose to buy from the utilities or third-party service providers.

Typical components of a smart grid include the following:

- Advanced sensing and control devices including smart meters, supervisory control and data acquisition (SCADA) and distribution and substation automation;
- Consumer energy monitoring and management devices and systems;
- Real time digital two way telecommunications, including advanced metering infrastructure (AMI); and
- Enterprise software and systems to enable utilities to manage the smart grid.

Grid modernization when coupled with smart end use technologies can help customer better manage their energy use, enabling customers to run appliances off peak, and enabling them to benefit from increased reliability. To the extent that changes in consumer's electricity usage patterns result in less energy consumption, lower demand or the ability to accommodate more renewable energy generation resources, efficiency and sustainability will be addressed.

Customers can then authorize the sharing of this information with third-party providers or use the information to procure more cost-effective services or more desirable services from utility and third-party providers. Customers with particular needs such as, for example, backup power supply, smart-device enabled systems, or distributed energy resources can use these systems to increasingly design their own energy management systems and to reduce their costs and their dependence on fuel-oil, propane, and even transportation fuels.

Policymakers seeking to implement a smart grid will need to consider the following issues:

- How will smart grid deployment integrate with the EERS?
- Consideration of the EERS will move the NHPUC's regulatory regime.to more flexible regulatory models such as a decoupling mechanism, dynamic and time of use pricing, smart grid investments and other advanced customer driven energy management systems.
- What information will the PUC need to approve deployment and recovery of associated costs?

- How will dynamic pricing be adopted?
- How will the transition to a modern grid be managed?
- How will customers be educated in the benefits of grid modernization?
- How will home energy management systems and smart appliance fit into the EERS?
- How will customer data be handled?
- What will be the reporting requirements?

In order for these policies to take effect the PUC will need to determine if demand response and smart grid policies are in the public interest. Thus Staff urges the Commission to consider addressing these issues in parallel subject dockets. Assuming the findings support further action, Staff would anticipate that the Program Administrators would begin to consider adding the following additional elements into their portfolio of program development:

(a) Time of use pricing

(b) Critical peak pricing & Critical peak pricing with load control.

(c) Real time pricing.

(d) Peak time rebate

This clearly underlines the fact that a stronger and more flexible ERRS will depend on timely action in parallel dockets that overlap energy efficiency considerations.

<u>EM&V</u>

Q. Why is evaluation measurement and verification critical for an EERS?

A. As public policy has shifted from simply spending ratepayer funds on energy efficiency programs to established targets for energy savings, the accurate evaluation, measurement and verification (EM&V) of those savings has taken on a much more important role. Both policymakers and utilities want to ensure that the utilities are actually meeting the energy efficiency targets; that ratepayer funds are being judiciously spent; and that the energy efficiency programs are cost effective. The need for verification of savings is further exacerbated by ISO NE requirements which in return for commitments on energy efficiency and demand savings which can be used in the forward capacity market to postpone additional capacity, the utilities receive forward capacity payments to apply to their energy savings programs.

Q. What does EM&V embrace?

A. According to the LBNL evaluation can be defined as the “performance of studies and activities aimed at determining the effects of an energy efficiency program or portfolio.”[69] Additionally. the LBNL states that measurement and verification embraces “ data collection, monitoring, and analysis associated with the calculation of gross energy and demand savings from individual sites or projects.” Properly implemented EM&V provides the tools to ensure that energy savings are realized and achieved in a cost effective manner.

Q. Why is EM&V so vital?

[69] Schiller, S.R., Goldman, C.A., and Galawish, E., *National Energy Efficiency Evaluation, Measurement and Verification (EM&V) Standard: Scoping Study of Issues and Implementation Requirements.* LBNL.

A. Consistent measurement and reporting is a logical and necessary part of any energy efficiency program or portfolio. Effective EM&V is needed for transparency and credibility of the programs.

Evaluation enables policymakers to ensure that ratepayer funds are being spent prudently; highlight the fact that energy efficiency is a resource that can be relied on now and in the future; demonstrates the ability to rely on and plan energy efficiency as part of the utility's broader resources; serves as the basis for translating energy savings into air pollution reduction. Additionally EM &V demonstrates compliance with ISO NE M&V standards for Energy efficiency resources bid into Forward Capacity Markets as well as providing feedback on an on-going basis enabling improvements in program design and delivery and cost effectiveness.

Q. **How should EM&V be implemented in NH under an EERS regime?**

A. Staff believes that the utilities have done a credible job in managing the EM&V process to date under the Core energy efficiency programs. Despite the absence of a state wide Technical Resource Manual (TRM), the utilities have effectively coordinated their efforts to provide evaluations of their programs in a largely uniform manner.

Going forward, Staff believes that the critical nature of the EM&V analysis will require the hiring of independent consultants, with the results being submitted to the Commission for acceptance. Typically the expense of performing an EM &V analysis are incorporated in EERS program costs and vary between 3-5% of program costs. At present the EM&V analysis within Core represents 5% of program costs.

One of the challenges facing EM &V is that different methodologies are used to conduct the analysis. This can lead to difficulty when comparing programs among utilities within a state. ISO-NE err on the side of caution when allowing efficiency to be bid into the wholesale capacity market due to uncertainty related to the reliability of energy savings.

In the Northeast policymakers, utilities and industry stakeholders are realizing the benefits of addressing EM&V on a regional basis. The North East Efficiency Partnership (NEEP) has convened a regional EM&V forum bringing together interested stakeholders to support the development of consistent protocols to evaluate, measure and verify and report the savings, costs and emission impacts of energy efficiency and other demand side resources.

Staff would recommend the adoption where possible of the standardized documentation that will serve to simplify the process and increase the level of transparency for the resulting data.

Staff also recommends that New Hampshire join on of the Technical Resource Manual compacts, i.e., Mass, RI and Connecticut, or the Mid-Atlantic states, in developing a digitized version of a TRM for widespread use.

Suggested implementation time line

Q. What is the recommended implementation timeline for the EERS?

A. Staff recommends that the implementation date for the EERS should be January 2017.This would require the following calendar:

- April 2016, Hearings on EERS;
- June 2016, NHPUC Order on EERS issued;
- July 2016, Testimony on LRAM filed in July;
- September 2016, Filing of the first triennium plan;
- October 2016, Order issued by the PUC on the LRAM; and
- December 2016, Order issued by PUC approving the first triennium plan.

This timeline is feasible assuming the following:

- Limited change relative to Core program in the first year facilitating a gradual adjustment;
- The PUC establishes a suitable source of funding to be effective on January 1, 2017;
- The PUC approves the implementation of a lost revenue recovery mechanism; and
- The PUC -confirms the role of the EESE Board as the EERS Advisory Council.

I. STAFF FINDINGS AND RECOMMENDATIONS

Q. What are the Staff findings and recommendations?

A. Staff's recommendations address the following four broad categories

<u>Targets</u>

1. A three year and ten year target will be established for the EERS. The three year target is defined, the 10 year target is considered notional.
2. Arising from the EERS financial model, two plans have been identified, Plan A comprises a limited plan and Plan B is a more ambitious plan.
3. Staff recommends adoption of Plan B.
4. Under Plan B and based on a 2014 base year, the three year cumulative electric savings target is 2.04% while the ten year notional electric savings target is 14.48%.
5. Under Plan B, and based on a 2014 base year, the three year gas savings target is 2.39% while the ten year notional gas savings target is 13.96%.
6. The current level of performance incentives will remain unchanged at the 2016 core levels of 10% for both electricity and gas utilities

Funding

7. In order to compensate the utilities for lost revenues associated with energy efficiency, a lost revenue recovery mechanism is recommended for the initial 3-year period, to be replaced by a decoupling mechanism to be considered in the future.
8. Under the recommended Plan B, for electric utilities the three-year funding requirement including PI and LRAM will be $108,215, 077.00. The equivalent funding requirement for gas utilities will be $32,363,896.00.
9. For the initial triennium, it is anticipated that funding will be achieved by raising the SBC or the LDAC.
10. To meet the initial three year targets assuming primary funding will comprise SBC and LDAC charges, the increase in the SBC per kWh under Plan B would be in the range of $0.0022 per kWh to $0.0170 per kWh. For LDAC during the initial three years the LDAC rate per therm. would be in the range of $0.034 per therm. to $0.124 per therm.
11. Staff recommends that beyond increases in the SBC and LDAC charges, the permanent EERS Advisory Council and stakeholders collaborate with the utilities in developing sources of private capital to be implemented following the first three year review.

Possible sources of private capital may include loan portfolio sales as well as asset backed securitization. Staff have identified at least ten such paradigms that are currently in place or being developed.

Implementation

12. Staff recommends that the Commission designate the EESE Board as its Permanent EERS Advisory Council and authorize funding for technical resources.
13. The Permanent EERS Advisory Council would have as a primary role the development of a consensus between stakeholders around a specific set of energy efficiency issues related to the EERS.
14. Staff recommends that to facilitate the work of the Permanent EERS Advisory Council, an independent facilitator be appointed to manage the agenda, moderate discussions and motivate consensus.
15. From its operating budget, the Permanent EERS Advisory Council would be able to draw upon energy efficiency consultants.
16. The Permanent EERS Advisory Council should transition from focusing primarily on program design to embrace a broader mandate that would anticipate tackling complex problems such as the development of a New Hampshire specific technical resource manual and the development of specific evaluation measurement and verification protocols.
17. Concerning the future direction of energy efficiency program activity, it will depend in part on Commission progress within the broad area of demand response and smart grid technology;, however, based on an analysis of Core programs to date suggested short run areas may include Performance Contracting; prescriptive /IT and Office equipment as well as Custom Data Centers; self-directed programs and voltage reduction /high efficiency transformers. In the longer term, critical peak pricing and critical peak pricing with load control, real time pricing, and peak time rebates may be considered.

18. Staff considers EM&V strengthening to be a vital part of the EERS program, and thus has anticipated considerable funding be set aside for a New Hampshire specific Training Resources Manual and for the Permanent EERS Advisory Council to hire independent consultants as well as specialists and experts as needed, to ensure transparency and credibility of the programs.

Start Date

19. Staff recommends that the EERS commence operation on January 1, 2017.

Attachment 1

Educational and Professional Background

James J. Cunningham, Jr.

I am employed by the New Hampshire Public Utilities Commission (Commission) as a Utility Analyst. My business address is 21 S. Fruit Street, Suite 10, Concord New Hampshire, 03301.

I am a graduate of Bentley University, Waltham, Massachusetts, and I hold a Bachelor of Science-Accounting Degree. Prior to joining the Commission I was employed by the General Electric Company (GE). While at GE, I graduated from the Corporate Financial Management Training Program and held assignments in General Accounting, Government Accounting & Contracts and Financial Analysis.

In 1988, I joined the staff of the NHPUC. I have provided expert testimony pertaining to depreciation studies, actuarial studies for pension and retirement benefits, energy efficiency programs and other topics pertaining to NH electric, natural gas, water, and steam utilities. In 1995, I completed the NARUC Annual Regulatory Studies Program at Michigan State University, sponsored by the National Association of Regulatory Utility Commissioners. In 1998, I completed the Depreciation Studies Program, sponsored by the Society of Depreciation Professionals, Washington, D.C. I am a member of the Society of Depreciation Professionals (SDP). In 2008, I was promoted to my current position of Utility Analyst.

Educational and Professional Background

Jay E. Dudley

I started at the Commission in June of 2015 as a Utility Analyst in the Electric Division. Before joining the Commission, I was employed at the Vermont Public Service Board ("PSB") for seven years as a Utility Analyst and Hearing Officer. In that position I was primarily responsible for the analysis of financing and accounting order requests filed by all Vermont utilities, including review of auditor's reports, financial projections, and securities analysis. As Hearing Officer, I managed and adjudicated cases involving a broad range of utility-related issues including rate investigations, energy efficiency, consumer complaints, utility finance, construction projects, condemnations, and telecommunications. Prior to working for the PSB, I worked in the commercial banking sector in Vermont for twenty years where I held various management and administrative positions. My most recent role was as Vice President and Chief Credit Officer for Lyndon Bank in Lyndonville, Vermont. In that position I was responsible for directing and administering the analysis and credit risk management of the bank's loan portfolio, including internal loan review, regulatory compliance, and audit.

In performing those responsibilities, I also provided oversight for the commercial and retail lending functions with detailed financial analysis of large corporate relationships, critique of loan proposals and loan structuring, consultation on business development efforts, and advised the Board of Directors on loan approvals and loan portfolio quality. Prior to my role as Chief Credit Officer, I held the position of Vice President of Loan Administration. In this position, I was responsible for directing and administering the underwriting, processing, and funding of all commercial, consumer, and residential mortgage loans. My responsibilities also included the management of loan processing and loan origination staff and partnering with the Compliance Officer to monitor and ensure compliance with all banking laws, regulations, and the bank's lending policy. Previous to my position as Loan Administration Vice President, I held the position of Assistant Vice President of Commercial Loan Administration with Passumpsic Savings Bank in St. Johnsbury, Vermont. In that role, I was responsible for supervising loan administration and loan operations within the commercial lending division of the bank.

I received my Bachelor of Arts degree in Political Science from St. Michael's College. Throughout my career in banking, I took advantage of numerous continuing education opportunities involving college level coursework in the areas of accounting, financial analysis, law, economics, and regulatory compliance. Also, during my career with the PSB I took advantage of various continuing education opportunities including the Regulatory Studies Program at Michigan State University and Utility Finance & Accounting for Financial Professionals at the Financial Accounting Institute.

Educational and Professional Background

Leszek Stachow

I am employed by the New Hampshire Public Utilities Commission (Commission) as Assistant Director of the Electric Division. My business address is 21 S. Fruit Street, Suite 10, Concord, New Hampshire, 03301.

I am a graduate of the following institutions of higher learning: University of Keele, Keele, Staffordshire, United Kingdom, from which I received a BA Triple Honors in Economics, Politics and History, and subsequently from the University of Sussex, Brighton, United Kingdom, from which I received a Masters in Political Economy.

While pursuing a PhD at the Massachusetts Institute of Technology in Cambridge, Mass, I concurrently served as a faculty member at St. Anselm College, NH and adjunct faculty at the Whittemore School of Business and Economics of the University of New Hampshire, where I taught regulatory economics. In 1987 I joined the Economics department of the New Hampshire Public Utilities Commission where I primarily supported rate cases in the telecommunications and energy sectors.

In 1988, I completed the NARUC Annual Regulatory Studies Program at Michigan State University, sponsored by the National Association of Regulatory Utility Commissioners as well as sundry other targeted regulatory courses.

In 1992, I was appointed regional manager for Central Europe on behalf of management consulting firm, Booz Allen & Hamilton. In that capacity I advised numerous government agencies in Central and Eastern Europe, the Middle East, Africa, and Latin

America on optimizing the functioning of energy, telecommunications, water/waste water, and gas sector regulatory bodies and markets.

In 2004, I was employed by Camp Dresser McKee to develop their Central European engineering consulting business. Beyond a primary focus on mergers and acquisitions, I was appointed President and manager of CDM Poland, as well as director of CDM AG in Germany.

After retiring from my business activities, I returned to the Commission in 2010, where I initially supported the telecommunications division and latterly the gas and electric divisions.

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EERS

Attachment 2

Annual State EERS Targets

Electric Utilities:	**Plan A**
	Plan B
Gas Utilities:	**Plan A**
	Plan B

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Attachment 2

Annual State EERS Targets

Electric Utilities: Plan A

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Electric - Savings Targets

Plan A

Schedule JJC-1

Electric kWh Savings Summary						
		Percent	Annual Savings		Cumulative Savings	
Year	Description	Year-To-Year kWh Saving Increase	kWh	Percent to 2014 kWh Sales (1) (2)	kWh	Percent to 2014 kWh Sales
2014	Actual kWh Savings		67,728,171	0.63%		
2015	Approved Core		56,979,474	0.53%		
2016	Proposed Core Upd		53,087,627	0.49%		
2017	Short-Term	10.00%	58,396,390	0.54%	58,396,390	0.54%
2018	Short-Term	11.00%	64,819,993	0.60%	123,216,382	1.14%
2019	Short-Term	12.00%	72,598,392	0.67%	195,814,774	1.82%
2020	Long-Term	13.00%	82,036,183	0.76%	277,850,957	2.58%
2021	Long-Term	13.00%	92,700,886	0.86%	370,551,843	3.44%
2022	Long-Term	13.00%	104,752,002	0.97%	475,303,844	4.41%
2023	Long-Term	13.00%	118,369,762	1.10%	593,673,606	5.51%
2024	Long-Term	13.00%	133,757,831	1.24%	727,431,437	6.75%
2025	Long-Term	13.00%	151,146,349	1.40%	878,577,786	8.16%
2026	Long-Term	13.00%	170,795,374	1.59%	1,049,373,160	9.74%

(1) Actual kWh sales for year 2014 are used for measurement purposes — 10,770,750,548

(2) See Schedule 8 for percenge of kWh sales for other New England States

EERS
kWh Savings Details - Electric Utilities

Plan A

Schedule JJC-1A

Description	Year	2014 Starting Points	% Annual Savings to 2014 Usage	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
				Cumulative Savings Targets By End of Each Forecast Year									
Annual Savings	2014 Actual	67,728,171	0.63%										
	2015 Core	56,979,474	0.53%										
	2016 Core	53,087,627	0.49%										
EERS	2017	58,396,390	0.54%	58,396,390	58,396,390	58,396,390	58,396,390	58,396,390	58,396,390	58,396,390	58,396,390	58,396,390	58,396,390
EERS	2018	64,819,993	0.60%		64,819,993	64,819,993	64,819,993	64,819,993	64,819,993	64,819,993	64,819,993	64,819,993	64,819,993
EERS	2019	72,598,392	0.67%			72,598,392	72,598,392	72,598,392	72,598,392	72,598,392	72,598,392	72,598,392	72,598,392
EERS	2020	82,036,183	0.76%				82,036,183	82,036,183	82,036,183	82,036,183	82,036,183	82,036,183	82,036,183
EERS	2021	92,700,886	0.86%					92,700,886	92,700,886	92,700,886	92,700,886	92,700,886	92,700,886
EERS	2022	104,752,002	0.97%						104,752,002	104,752,002	104,752,002	104,752,002	104,752,002
EERS	2023	118,369,762	1.10%							118,369,762	118,369,762	118,369,762	118,369,762
EERS	2024	133,757,831	1.24%								133,757,831	133,757,831	133,757,831
EERS	2025	151,146,349	1.40%									151,146,349	151,146,349
EERS	2026	170,795,374	1.59%										170,795,374
Cumulative Savings			*ACEEE-EERS ramps up to new sav of 1.5% of prior yr sales*	58,396,390	123,216,382	195,814,774	277,850,957	370,551,843	475,303,844	593,673,606	727,431,437	878,577,786	1,049,373,160
% Cumulative Savings to 2014 Actual Usage				0.54%	1.14%	1.82%	2.58%	3.44%	4.41%	5.51%	6.75%	8.16%	9.74%
								VEIC=1.75 (Equiv in 5 years)					*GDS=10.8% (Pot Obtain in 10 yrs)*

Comments:

1. Annual savings in 2026 achieve 1.6% of 2014 actual usage, in line with ACEEE -EERS expectation.
2. Cumulative savings by 2021 achieve 3.44% of 2014 actual usage, twice as much as VEIC's November 2013 Report of 1.7% by end of year five.
3. Cumulative savings by 2026 achieve 9.75% of 2014 actual usage, one percentage point lower than GDS' January 2009 Report of 10.8%.
4. 2014 Actual kWh Elec Usage for the four NH utilities. 10,770,750,548

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EERS
Electric - Spending and Funding

Plan A

Schedule JJC-2

Year	Description	Spending: Annual Saving kWh	Unit Cost To Achieve Savings	Utility Spend Excl. PI & LR	Plus: ESSE Consult.	Plus: Est. Perm. EESE Brd.	Plus: Est. TRM Costs	Plus: PI 10% Cap	Plus: LR	Less: RGGI/ISO	Total	SBC: Calculated Rate	Excess/(Shortfall) From Existing $0.0018 SBC	Incremental Monthly Residential Bill Impact	Incremental Monthly Gen'l Serv. Bill Impact
		(1)	(2)		(3)	(4)	(5)	(6)	(7)			(8)		(9)	(9)
2014	Actual	67,728,171													
2015	Core Filing	56,979,474													
2016	Core Filing	53,087,627													
2017	Short-Term	58,396,390	$ 0.427	$ 24,911,761	$ 100,000			$ 2,491,176	$ -	$ (5,000,000)	22,502,937	$ 0.0020	$ (2,723,892.77)	$ 0.174	$ 1.735
2018	Short-Term	64,819,993	$ 0.437	$ 28,343,356	$ 102,500			$ 2,834,336	$ -	$ (5,000,000)	26,280,191	$ 0.0024	$ (6,501,147.31)	$ 0.414	$ 4.141
2019	Short-Term	72,598,392	$ 0.448	$ 32,538,172	$ 105,063			$ 3,253,817	$ 920,465	$ (5,000,000)	31,817,517	$ 0.0029	$ (12,038,472.94)	$ 0.767	$ 7.669
2020	Long-Term	82,036,183	$ 0.459	$ 37,687,338	$ 107,689	$ 1,000,000	$ 500,000	$ 3,768,734	$ 3,159,382	$ (5,000,000)	41,223,143	$ 0.0038	$ (21,444,098.74)	$ 1.366	$ 13.661
2021	Long-Term	92,700,886	$ 0.471	$ 43,651,359	$ 110,381	$ 1,025,000	$ 250,000	$ 4,365,136	$ 3,962,266	$ (5,000,000)	48,364,142	$ 0.0044	$ (28,585,098.45)	$ 1.821	$ 18.210
2022	Long-Term	104,752,002	$ 0.483	$ 50,559,187	$ 113,141	$ 1,050,625	$ 256,250	$ 5,055,919	$ 4,061,322	$ (5,000,000)	56,096,444	$ 0.0051	$ (36,317,400.02)	$ 2.314	$ 23.136
2023	Long-Term	118,369,762	$ 0.495	$ 58,560,178	$ 115,969	$ 1,076,891	$ 262,656	$ 5,856,018	$ 4,162,855	$ (5,000,000)	65,034,568	$ 0.0059	$ (45,255,523.97)	$ 2.883	$ 28.829
2024	Long-Term	133,757,831	$ 0.507	$ 67,827,327	$ 118,869	$ 1,103,813	$ 269,223	$ 6,782,733	$ 4,266,927	$ (5,000,000)	75,368,890	$ 0.0069	$ (55,589,846.32)	$ 3.541	$ 35.413
2025	Long-Term	151,146,349	$ 0.520	$ 78,561,001	$ 121,840	$ 1,131,408	$ 275,953	$ 7,856,100	$ 4,373,600	$ (5,000,000)	87,319,903	$ 0.0079	$ (67,540,858.98)	$ 4.303	$ 43.026
2026	Long-Term	170,795,374	$ 0.533	$ 90,993,280	$ 124,886	$ 1,159,693	$ 282,852	$ 9,099,328	$ 4,482,940	$ (5,000,000)	101,142,979	$ 0.0092	$ (81,363,935.29)	$ 5.183	$ 51.832

(1) Annual savings: targets for annual savings are shown on Schedule 1.
(2) Unit cost: Utility spending, excl PI, divided by annual kWh savings. Eversouce avg. of 2014-2016 in then year dollars, with 2.5% ann. Escalation, excluding PI. See Schedule 5.
(3) Estimated amount to provide a placeholder for an administrative resource to assist permanent EESE Board.
(4) Estimated amount to provide a placeholder for estimated cost of Permanent EESE Board.
(5) Estimated amount to provide a placeholder for estimated cost of TRM.
(6) PI and LR: Retain PI at 10% Cap when LR is introduced.
(7) Lost Revenue (LR): Lost revenues is adjusted to reflect "incremental" and "retirement" adjustments. See Schedule 3.
(8) SBC Rates: 2017-2026 rates are calculated using 2016 kWh sales per Core filing for all years (excluding $5,000,000 in RGGI/ISO revenue).
Year 2016 kWh sales are taken from the 2016 Update Core filing at p. 2 ($19,779,044 / $0.0018 per kWh): 10,988,357,778
(9) Based on illustrated monthly usage of 700 kWh and 7,000 kWh for Res and Gen'l Service respectively (9/16 Slides, p. 4 and 5)

DE 15-137
EERS
Electric - Lost Revenue

Plan A

Schedule JJC-3

		Annual kWh Savings for Lost Rev.					Lost Revenue Amount			
Year	Description	Annual Saving Estimate	Adjust For Increment (1)	Adjust For Retirement (2)	Adjusted Annual Savings	Cumulative kWh Savings for LR	Estimated LR $ Per kWh (3)	LR Amount (Not < $0)	Cap $ (4)	LR - Lower of Calc. or Cap $
2014	*Actual*	*67,728,171*						$ -		
2015	*Approved Core*	*56,979,474*						$ -		
2016	*2016 Core Update*	*53,087,627*						$ -		
2017	Short-Term	58,396,390	(59,265,091)	(47,845,506)	(48,714,207)	(48,714,207)	$ 0.043	$ -	$ 3,589,617	$ -
2018	Short-Term	64,819,993	-	(32,522,220)	32,297,773	(16,416,434)	$ 0.044	$ -	$ 3,679,358	$ -
2019	Short-Term	72,598,392	-	(35,738,327)	36,860,065	20,443,631	$ 0.045	$ 920,465	$ 3,771,342	$ 920,465
2020	Long-Term	82,036,183	-	(34,021,047)	48,015,135	68,458,766	$ 0.046	$ 3,159,382	$ 3,865,625	$ 3,159,382
2021	Long-Term	92,700,886	-	(34,613,137)	58,087,749	126,546,515	$ 0.047	$ 5,986,143	$ 3,962,266	$ 3,962,266
2022	Long-Term	104,752,002	-	(28,500,340)	76,251,662	202,798,177	$ 0.048	$ 9,832,972	$ 4,061,322	$ 4,061,322
2023	Long-Term	118,369,762	-	(28,202,280)	90,167,482	292,965,659	$ 0.050	$ 14,559,999	$ 4,162,855	$ 4,162,855
2024	Long-Term	133,757,831	-	(27,751,924)	106,005,907	398,971,565	$ 0.051	$ 20,324,059	$ 4,266,927	$ 4,266,927
2025	Long-Term	151,146,349	-	(26,402,521)	124,743,828	523,715,393	$ 0.052	$ 27,345,615	$ 4,373,600	$ 4,373,600
2026	Long-Term	170,795,374	-	(25,002,972)	145,792,402	669,507,795	$ 0.054	$ 35,832,067	$ 4,482,940	$ 4,482,940

Footnotes:

(1) Projected LR is reduced to reflect "incremental" savings levels in order to remove average 2014-2016 savings levels which were achieved without LR.

(2) Projected LR is reduced to reflect prior installed savings that are "retired" during 2017-2026. See Schedule 6.

(3) Projected lost revenue per kWh is illustrated using Eversource's 2015 Res. Rate of $0.04079/kWh ($28.55/700 kWh) (9/16 Utilities' slides) as follows:

	Estimate Year 2015	Estimate Year 2016	Estimate Year 2017
Illustrated using Eversource Distribution Res Rate	$ 0.041	$ 0.042	$ 0.043

(4) Calculation of amount of lost revenue cap (assuming 0.25%):

	Actual Year 2014	Estimate Year 2015 (Escal. At 2.5%)	Estimate Year 2016 (Escal. At 2.5%)	Estimate Year 2017 (Escal. At 2.5%)
Estimated Distribution Revenue	$ 1,333,326,584	$ 1,366,659,749	$ 1,400,826,242	$ 1,435,846,898

	Year 2017	Year 2018	Year 2019	Year 2020	Year 2021	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Rev.	$ 1,435,846,898	$ 1,471,743,071	$ 1,508,536,648	$ 1,546,250,064	$ 1,584,906,315	$ 1,624,528,973	$ 1,665,142,198	$ 1,706,770,753	$ 1,749,440,021	$ 1,793,176,022
Cap%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
Cap	$ 3,589,617	$ 3,679,358	$ 3,771,342	$ 3,865,625	$ 3,962,266	$ 4,061,322	$ 4,162,855	$ 4,266,927	$ 4,373,600	$ 4,482,940

Note: LR is difficult to calculate and it's important to avoid windfall profits - i.e., lost fixed cost recoveries that are over and above utilities' opearting costs.

Plan A

Schedule JJC-4

EERS
Electric - Details of Benefit Cost

	Benefits					Costs			
Year	Annual Pure kWh Savings	Annual Equivalent kWh Savings	Lifetime Equiv. kWh Savings	Benefits = Life kWh Sav x Rate/kWh	NPV Benefits 1.36% Disc. Rate	Utility Cost (Incl. PI & LR)	Util+Cust Installed Cost	NPV Costs 2.5% Disc. Rate	B/C
		(1)	(2)	(3)	(3)		(4)		
2017	58,396,390	75,547,041	1,080,021,518	$ 90,555,125	$ 90,555,125	$ 22,502,937	$ 38,052,456	$ 38,052,456	2.38
2018	64,819,993	83,857,216	1,198,823,885	$ 101,883,209	$ 100,516,189	$ 26,280,191	$ 44,439,792	$ 43,355,895	2.32
2019	72,598,392	93,920,082	1,342,682,751	$ 115,661,079	$ 112,578,132	$ 31,817,517	$ 53,803,407	$ 51,210,858	2.20
2020	82,036,183	106,129,692	1,517,231,509	$ 132,474,499	$ 127,213,289	$ 41,223,143	$ 69,708,316	$ 64,731,102	1.97
2021	92,700,886	119,926,552	1,714,471,605	$ 151,732,052	$ 143,751,016	$ 48,364,142	$ 81,783,744	$ 74,092,036	1.94
2022	104,752,002	135,517,004	1,937,352,914	$ 173,789,037	$ 180,976,499	$ 56,096,444	$ 94,859,063	$ 83,841,589	2.16
2023	118,369,762	153,134,215	2,189,208,793	$ 199,052,401	$ 183,555,673	$ 65,034,568	$ 109,973,426	$ 94,829,741	1.94
2024	133,757,831	173,041,663	2,473,805,936	$ 227,988,251	$ 207,397,448	$ 75,368,890	$ 127,448,761	$ 107,218,212	1.93
2025	151,146,349	195,537,079	2,795,400,708	$ 261,130,447	$ 234,382,238	$ 87,319,903	$ 147,657,918	$ 121,189,730	1.93
2026	170,795,374	220,956,899	3,158,802,800	$ 299,090,458	$ 264,851,929	$ 101,142,979	$ 171,032,734	$ 136,950,761	1.93

footnotes:

(1) Factor for equivalent kWh saved, based on 3-year average (2014-2016)		1.29	See Sch. 7
(2) Est. average lifetime for equivalent savings, based on 3-year average (2014-2016)		14.3	See Sch. 7
(3) Est. value of benefits/lifetime kWh, based on 3-year average (2014-2016)	$	0.084	See Sch. 7
(4) Estimated installed cost factor (Total/Utility Cost)based on 3-year average (2014-2016).		1.69	See Sch. 7

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EERS

Plan A

Schedule JJC-5

Derivation of Utility Unit Cost to achieve KWh Saving (Eversource as proxy, excl PI):
Annual Basis

Forecast for 2015-2026:		Amount	
2015 Escalation at 2.5%	$	0.378	
2016 Escalation at 2.5%	$	0.416	(1)
2017 Escalation at 2.5%	$	0.427	
2018 Escalation at 2.5%	$	0.437	
2019 Escalation at 2.5%	$	0.448	
2020 Escalation at 2.5%	$	0.459	
2021 Escalation at 2.5%	$	0.471	
2022 Escalation at 2.5%	$	0.483	
2023 Escalation at 2.5%	$	0.495	
2024 Escalation at 2.5%	$	0.507	
2025 Escalation at 2.5%	$	0.520	
2026 Escalation at 2.5%	$	0.533	

Footnotes:

(1) Calculation of 2016 Utility Unit Cost (Eversource):

				Average in 2016 Price Levels				
		2014 Actual		2015 Core		2016 Core		Average
Utility Cost (excl PI)	$	19,113,200	$	18,424,500	$	17,486,600		
Annual kWh Saving		51,888,800		43,528,700		40,882,600		
Unit Cost per kWh	$	0.368	$	0.42	$	0.428		
2015 - Escal at 1.025	$	0.378						
2016 - Escal at 1.025	$	0.387	$	0.434	$	0.428	$	0.416

Comparison to Cost to Achieve kWh Savings in New England States:
Lifetime Basis:

		Year 2013
ME	$	0.0200
NH	$	0.0310
VT	$	0.0320
MA	$	0.0350
RI	$	0.0370
CT	$	0.0400

Source: DE 15-248, PSNH Least Cost Integrated Resource Plan, June 19, 2015, p. 22.

DE 15-137 **Plan A** Schedule JJC-6

EERS

Derivation of Estimated Retirement of Prior EE Installations

Lifetime Sav		Annual Retirements					Retirement kWh
		Core	Co. Specific	Lifetime Savings Life Savings	Life (Years)	Annual Savings	Discounted By 50 percent
					(1)		(2)
Year Installed	Year Retired						
2003	2017			1,368,000,000	14.30	95,691,012	47,845,506
2004	2018	851,633,400	78,242,775	929,876,175	14.30	65,044,439	32,522,220
2005	2019	972,035,330	49,795,874	1,021,831,204	14.30	71,476,654	35,738,327
2006	2020	934,721,338	38,009,365	972,730,703	14.30	68,042,095	34,021,047
2007	2021	925,977,328	63,682,413	989,659,741	14.30	69,226,274	34,613,137
2008	2022	749,773,432	65,109,047	814,882,479	14.30	57,000,679	28,500,340
2009	2023	739,944,852	66,415,502	806,360,354	14.30	56,404,560	28,202,280
2010	2024	728,397,258	65,086,500	793,483,758	14.30	55,503,848	27,751,924
2011	2025	684,593,766	70,307,829	754,901,595	14.30	52,805,042	26,402,521
2012	2026	668,386,293	46,499,357	714,885,650	14.30	50,005,944	25,002,972

footnotes:

(1) Based on 3-year average (Sch. 7): 14.30

(2) It is difficult to project future customer purchase of standard vs. high efficiency equipment; therefore, a discount factor of 50% is applied.

DE 15-137
EERS
Data for Calculation of Benefit Cost (BC) Ratios

Plan A

Schedule JJC-7

	2014 Actual (final)		2015 Core		2016 Core		Average	
Ratio of Equiv to Pure kWh (Eversource):								
Electric annual kWh Savings		51,888,800		43,528,700		40,882,600		45,433,367
Annual MMBtu Savings	69,186		28,337		39,100		45,541	
kWh factor	293	20,271,498	293	8,302,741	293	11,456,241	293	13,343,493
Equiv kWh Savings		72,160,298		51,831,441		52,338,841		58,776,860
Factor for Equiv. kWh		1.39		1.19		1.28		1.29
Measure Life (Eversource):								
Electric lifetime kWh Savings		694,571,000		565,700,800		553,930,600		604,734,133
Lifetime MMBtu Savings	1,132,264		575,524		703,891		803,893	
kWh Factor	293	331,753,352	293	168,628,473	293	206,240,122	293	235,540,649
Equiv kWh Savings		1,026,324,352		734,329,273		760,170,722		840,274,782
Annual Equivalent kWh Savings		72,160,298		51,831,441		52,338,841		58,776,860
Measure Life		14.2		14.2		14.5		14.30
Benefits per equivalent lifetime kWh saved (Eversource):								
Benefit Dollars		$ 86,016,400		$ 62,033,700		$ 63,310,100		$ 70,453,400
Lifetime Equivalent kWh savings		1,026,324,352		734,329,273		760,170,722		840,274,782
Rate per kWh		$ 0.084		$ 0.084		$ 0.083		$ 0.084
Customer Cost Factor (Eversource):								
"Customer" Cost		$ 16,649,700		$ 13,285,100		$ 10,938,600		$ 13,624,467
"Utility" Cost Incl. PI at 7.5%	$ 19,113,200	$ 20,546,690	$ 18,424,500	$ 19,806,338	$ 17,486,600	$ 18,798,095	18,341,433	19,717,041
"Installed" Cost		$ 37,196,390		$ 33,091,438		$ 29,736,695		$ 33,341,508
Installed Cost Factor		$ 1.81		$ 1.67		$ 1.58		$ 1.69

EERS

EERS Savings Targets

Plan A

Schedule JJC-8

EERS Comparisons kWh Savings as % of Load (1)							EERS Planned Savings or New Hampshire	
							Short-Term	Long-Term
Industry	Year	ME	VT (2)	RI	CT	MA	Year 2019	Year 2026
Electricity	2014	1.6%	2.0%	2.5%	1.4%	2.5%		
	2015	1.6%			1.4%	2.6%	0.7%	1.6%

Footnotes:

(1) Source: ACEEE, *Energy Efficiency Resource Standards*, April, 2014.

(2) Includes demand response targets.

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EERS

Summary of PI and Lost Revenue Impacts for certain years

Plan A

Schedule JJC-9

			Utility Spending	PI	Pecent of Util Spending	Percent of Utility Sales $
Year 2014 Actual:			*Final PI Report*			$ 1,333,326,584
	PI	Eversource	$ 19,113,200	$ 1,755,017	9.2%	
		Liberty	$ 2,168,000	$ 196,915	9.1%	
		Unitil	$ 2,760,000	$ 261,415	9.5%	
		NHEC	$ 1,839,500	$ 159,125	8.7%	
		Total	$ 25,880,700	$ 2,372,472	9.2%	0.2%
Year 2017 Est:			*Schedule 2*			$ 1,435,846,898
	PI			$ 2,491,176	10.0%	
	Lost Rev			$ -		
	Total		$ 24,911,761	$ 2,491,176	10.0%	0.2%
Year 2018 Est:			*Schedule 2*			$ 1,471,743,071
	PI			$ 2,834,336		
	Lost Rev			$ -		
	Total		$ 28,343,356	$ 2,834,336	10.0%	0.2%
Year 2019 Est:			*Schedule 2*			$ 1,508,536,648
	PI			$ 3,253,817		
	Lost Rev			$ 920,465		
	Total		$ 32,538,172	$ 4,174,282	12.8%	0.3%
Year 2020			*Schedule 2*			
	PI			$ 3,768,734		$ 1,546,250,064
	Lost Rev			$ 3,159,382		
	Total		$ 37,687,338	$ 6,928,116	18.4%	0.4%
Year 2021			*Schedule 2*			
	PI			$ 4,365,136		$ 1,584,906,315
	Lost Rev			$ 3,962,266		
	Total		$ 43,651,359	$ 8,327,402	19.1%	0.5%
Year 2022			*Schedule 2*			
	PI			$ 5,055,919		$ 1,624,528,973
	Lost Rev			$ 4,061,322		
	Total		$ 50,559,187	$ 9,117,241	18.0%	0.6%
Year 2023			*Schedule 2*			$ 1,665,142,198
	PI			$ 5,856,018		
	Lost Rev			$ 4,162,855		
	Total		$ 58,560,178	$ 10,018,873	17.1%	0.6%
Year 2024			*Schedule 2*			$ 1,706,770,753
	PI			$ 6,782,733		
	Lost Rev			$ 4,266,927		
	Total		$ 67,827,327	$ 11,049,660	16.3%	0.6%
Year 2025			*Schedule 2*			$ 1,749,440,021
	PI			$ 7,856,100		
	Lost Rev			$ 4,373,600		
	Total		$ 78,561,001	$ 12,229,700	15.6%	0.7%
Year 2026			*Schedule 2*			$ 1,793,176,022
	PI			$ 9,099,328		
	Lost Rev			$ 4,482,940		
	Total		$ 90,993,280	$ 13,582,268	14.9%	0.8%
Note #1:	LR Only (2019-2026)			$ 29,389,757		
	Util. Spending (2019-2026)			$ 460,377,843		
	Percentage			6%		
Note #2:	PI + LR (2019-2026)			$ 75,427,541		
	Util. Spending (2019-2026)			$ 460,377,843		
	Percentage			16%		

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EERS

Attachment 2

Annual State EERS Targets

Electric Utilities: Plan B

DE 15-137
EERS
Electric - Savings Targets

Plan B

Schedule JJC-1

Electric kWh Savings Summary						
		Percent	Annual Savings		Cumulative Savings	
Year	Description	Year-To-Year kWh Saving Increase	kWh	Percent to 2014 kWh Sales (1)	kWh	Percent to 2014 kWh Sales
2014	Actual kWh Savings		67,728,171	0.63%		
2015	Approved Core		56,979,474	0.53%		
2016	Proposed Core Upd		53,087,627	0.49%		
2017	Short-Term	15.00%	61,050,771	0.57%	61,050,771	0.57%
2018	Short-Term	18.00%	72,039,910	0.67%	133,090,681	1.24%
2019	Short-Term	20.00%	86,447,892	0.80%	219,538,573	2.04%
2020	Long-Term	20.00%	103,737,470	0.96%	323,276,043	3.00%
2021	Long-Term	20.00%	124,484,964	1.16%	447,761,007	4.16%
2022	Long-Term	20.00%	149,381,957	1.39%	597,142,964	5.54%
2023	Long-Term	20.00%	179,258,348	1.66%	776,401,313	7.21%
2024	Long-Term	20.00%	215,110,018	2.00%	991,511,331	9.21%
2025	Long-Term	20.00%	258,132,022	2.40%	1,249,643,352	11.60%
2026	Long-Term	20.00%	309,758,426	2.88%	1,559,401,779	14.48%
	(1) Actual kWh sales for year 2014 are used for measurement purposes				10,770,750,548	

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EERS
Electric - Spending and Funding

Plan B

Schedule JJC-2

		Spending										SBC		Est. Monthly Residential Bill Impact	Est. Monthly Gen'l Service Bill Impact
Year	Description	Annual Saving kWh (1)	Unit Cost To Achieve Savings (2)	Utility Spending Excl. PI &LR	Plus: EESE Consult. (3)	Plus: Est. Permanent EESE Board (4)	Plus: Est. TRM Costs (5)	Plus: PI 10% Cap (6)	Plus: LR (7)	Less: RGGI/ISO	Total	Calculated Rate (8)	Excess/(Shortfall) From Existing $0.0018 SBC	(9)	(9)
2014	Actual	67,728,171													
2015	Core Filing	56,979,474													
2016	Core Filing	53,087,627													
2017	Short-Term	61,050,771	$ 0.427	$ 26,044,113	$ 100,000			$ 2,604,411	$ -	$ (5,000,000)	23,748,525	$ 0.0022	$ (3,969,480.81)	$ 0.253	$ 2.529
2018	Short-Term	72,039,910	$ 0.437	$ 31,500,355	$ 102,500			$ 3,150,036	$ -	$ (5,000,000)	29,752,891	$ 0.0027	$ (9,973,846.75)	$ 0.635	$ 6.354
2019	Short-Term	86,447,892	$ 0.448	$ 38,745,437	$ 105,063			$ 3,874,544	$ 1,988,618	$ (5,000,000)	39,713,661	$ 0.0036	$ (19,934,616.78)	$ 1.270	$ 12.699
2020	Long-Term	103,737,470	$ 0.459	$ 47,656,887	$ 107,689	$ 1,000,000	$ 500,000	$ 4,765,689	$ 5,255,756	$ (5,000,000)	54,286,021	$ 0.0049	$ (34,506,977.06)	$ 2.198	$ 21.982
2021	Long-Term	124,484,964	$ 0.471	$ 58,617,972	$ 110,381	$ 1,025,000	$ 250,000	$ 5,861,797	$ 7,924,532	$ (5,000,000)	68,789,682	$ 0.0063	$ (49,010,637.55)	$ 3.122	$ 31.222
2022	Long-Term	149,381,957	$ 0.483	$ 72,100,105	$ 113,141	$ 1,050,625	$ 256,250	$ 7,210,010	$ 8,122,645	$ (5,000,000)	83,852,776	$ 0.0076	$ (64,073,732.17)	$ 4.082	$ 40.817
2023	Long-Term	179,258,348	$ 0.495	$ 88,683,129	$ 115,969	$ 1,076,891	$ 262,656	$ 8,868,313	$ 8,325,711	$ (5,000,000)	102,332,669	$ 0.0093	$ (82,553,625.25)	$ 5.259	$ 52.590
2024	Long-Term	215,110,018	$ 0.507	$ 109,080,249	$ 118,869	$ 1,103,813	$ 269,223	$ 10,908,025	$ 8,533,854	$ (5,000,000)	125,014,032	$ 0.0114	$ (105,234,987.60)	$ 6.704	$ 67.039
2025	Long-Term	258,132,022	$ 0.520	$ 134,168,706	$ 121,840	$ 1,131,408	$ 275,953	$ 13,416,871	$ 8,747,200	$ (5,000,000)	152,861,979	$ 0.0139	$ (133,082,934.51)	$ 8.478	$ 84.779
2026	Long-Term	309,758,426	$ 0.533	$ 165,027,508	$ 124,886	$ 1,159,693	$ 282,852	$ 16,502,751	$ 8,965,880	$ (5,000,000)	187,063,571	$ 0.0170	$ (167,284,527.19)	$ 10.657	$ 106.567
					$ 1,120,338	$ 7,547,430	$ 2,096,934	$ 77,162,446	$ 57,864,195	$ (50,000,000)	$ 95,791,344				

(1) Annual savings: targets for annual savings are shown on Schedule 1.
(2) Unit cost: Utility spending, excl. PI, divided by annual kWh savings. Eversource avg. of 2014-2016 in then-year dollars, with 2.5% ann. Escalation, excluding PI. See Schedule 5.
(3) Estimated amount to provide a placeholder for an administrative resource to assist the Permanent EESE Board.
(4) Estimated amount to provide a placeholder for estimated cost of Permanent EESE Board
(5) Estimated amount to provide a placeholder for estimated cost of TRM.
(6) PI and LR: Retain PI at 10% Cap and when LR is introduced.
(7) Lost Revenue (LR): Lost revenues is adjusted to reflect "incremental" and "retirement" adjustments. See Schedule 3.
(8) SBC Rates: 2017-2026 rates are calculated using 2016 kWh sales per Core Update filing for all years (excluding $5,000,000 in RGGI/ISO revenue).
Year 2016 kWh sales are taken from the 2016 Update Core filing at p. 2 ($19,779,044 / $0.0018 per kWh): 10,988,357,778
(9) Based on illustrated monthly usage of 700 kWh and 7,000 kWh for Res and Gen'l Service respectively (9/16 Slides, p. 4 and 5)

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EERS
Electric - Lost Revenue

Plan B

Schedule JJC-3

Year	Description	Annual kWh Savings for Lost Rev.: Annual Saving Estimate	Adjust For Increment (1)	Adjust For Retirement (2)	Adjusted Annual Savings	Cumulative kWh Savings for LR	Lost Revenue Amount: Estimated LR $ Per kWh (3)	LR Amount (Not < $0)	Cap $ (4)	LR - Lower of Calc. or Cap $
2014	*Actual*	*67,728,171*						$ -		
2015	*Approved Core*	*56,979,474*						$ -		
2016	*2016 Core Update*	*53,087,627*						$ -		
2017	Short-Term	61,050,771	(59,265,091)	(47,845,506)	(46,059,826)	(46,059,826)	$ 0.043	$ -	$ 7,179,234	$ -
2018	Short-Term	72,039,910	-	(32,522,220)	39,517,690	(6,542,136)	$ 0.044	$ -	$ 7,358,715	$ -
2019	Short-Term	86,447,892	-	(35,738,327)	50,709,565	44,167,429	$ 0.045	$ 1,988,618	$ 7,542,683	$ 1,988,618
2020	Long-Term	103,737,470	-	(34,021,047)	69,716,423	113,883,852	$ 0.046	$ 5,255,756	$ 7,731,250	$ 5,255,756
2021	Long-Term	124,484,964	-	(34,613,137)	89,871,827	203,755,679	$ 0.047	$ 9,638,437	$ 7,924,532	$ 7,924,532
2022	Long-Term	149,381,957	-	(28,500,340)	120,881,617	324,637,297	$ 0.048	$ 15,740,524	$ 8,122,645	$ 8,122,645
2023	Long-Term	179,258,348	-	(28,202,280)	151,056,068	475,693,365	$ 0.050	$ 23,641,320	$ 8,325,711	$ 8,325,711
2024	Long-Term	215,110,018	-	(27,751,924)	187,358,094	663,051,459	$ 0.051	$ 33,776,584	$ 8,533,854	$ 8,533,854
2025	Long-Term	258,132,022	-	(26,402,521)	231,729,501	894,780,960	$ 0.052	$ 46,720,673	$ 8,747,200	$ 8,747,200
2026	Long-Term	309,758,426	-	(25,002,972)	284,755,454	1,179,536,414	$ 0.054	$ 63,128,806	$ 8,965,880	$ 8,965,880

Footnotes:
(1) Projected LR is reduced to reflect "incremental" savings levels in order to remove average 2014-2016 savings levels which were achieved without LR.
(2) Projected LR is reduced to reflect prior installed savings that are "retired" during 2017-2026. See Schedule 6.
(3) Projected lost revenue per kWh is illustrated using Eversource's 2015 Res. Rate of $0.04079/kWh ($28.55/700 kWh) (9/16 Utilities' Slides) as follows:

	Estimate Year 2015	Estimate Year 2016	Estimate Year 2017
Illustrated using Eversource Distribution Res Rate	0.041	0.042	0.043

(4) Calculation of amount of lost revenue cap):

	Actual Year 2014	Estimate Year 2015 (Escal. At 2.5%)	Estimate Year 2016 (Escal. At 2.5%)	Estimate Year 2017 (Escal. At 2.5%)
Estimated Distribution Revenue	$ 1,333,326,584	$ 1,366,659,749	$ 1,400,826,242	$ 1,435,846,898

	Year 2017	Year 2018	Year 2019	Year 2020	Year 2021	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Rev.	$ 1,435,846,898	$ 1,471,743,071	$ 1,508,536,648	$ 1,546,250,064	$ 1,584,906,315	$ 1,624,528,973	$ 1,665,142,198	$ 1,706,770,753	$ 1,749,440,021	$ 1,793,176,022
Cap%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Cap	$ 7,179,234	$ 7,358,715	$ 7,542,683	$ 7,731,250	$ 7,924,532	$ 8,122,645	$ 8,325,711	$ 8,533,854	$ 8,747,200	$ 8,965,880

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Electric - Details of Benefit Cost

Plan B

Schedule JJC-4

	Benefits					Costs			
Year	Annual Pure kWh Savings	Annual Equivalent kWh Savings	Lifetime Equiv. kWh Savings	Benefits = Life kWh Sav x Rate/kWh	NPV Benefits 1.36% Disc. Rate	Utility Cost (Incl. PI & LR)	Util+Cust Installed Cost	NPV Costs 2.5% Disc. Rate	B/C
		(1)	(2)	(3)	(3)		(4)		
2017	61,050,771	78,980,998	1,129,113,405	$ 94,671,267	$ 94,671,267	$ 23,748,525	$ 40,158,745	$ 40,158,745	2.36
2018	72,039,910	93,197,577	1,332,353,818	$ 113,231,380	$ 111,712,095	$ 29,752,891	$ 50,312,125	$ 49,085,000	2.28
2019	86,447,892	111,837,093	1,598,824,582	$ 137,725,592	$ 134,054,514	$ 39,713,661	$ 67,155,783	$ 63,919,841	2.10
2020	103,737,470	134,204,511	1,918,589,498	$ 167,518,392	$ 160,865,417	$ 54,286,021	$ 91,797,638	$ 85,243,233	1.89
2021	124,484,964	161,045,414	2,302,307,398	$ 203,755,970	$ 193,038,501	$ 68,789,682	$ 116,323,322	$ 105,383,188	1.83
2022	149,381,957	193,254,496	2,762,768,878	$ 247,832,462	$ 258,082,167	$ 83,852,776	$ 141,795,008	$ 125,326,126	2.06
2023	179,258,348	231,905,396	3,315,322,653	$ 301,443,580	$ 277,975,441	$ 102,332,669	$ 173,044,499	$ 149,215,729	1.86
2024	215,110,018	278,286,475	3,978,387,184	$ 366,651,855	$ 333,537,623	$ 125,014,032	$ 211,398,673	$ 177,842,355	1.88
2025	258,132,022	333,943,770	4,774,064,621	$ 445,965,984	$ 400,284,635	$ 152,861,979	$ 258,489,539	$ 212,154,403	1.89
2026	309,758,426	400,732,524	5,728,877,545	$ 542,437,346	$ 480,341,562	$ 187,063,571	$ 316,324,418	$ 253,289,933	1.90

footnotes:

(1) Factor for equivalent kWh saved, based on 3-year average (2014-2016)	1.29	See Sch. 7
(2) Est. average lifetime for equivalent savings, based on 3-year average (2014-2016)	14.3	See Sch. 7
(3) Est. value of benefits/lifetime kWh, based on 3-year average (2014-2016)	$ 0.084	See Sch. 7
(4) Estimated installed cost factor (Total/Utility Cost)based on 3-year average (2014-2016).	1.69	See Sch. 7

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EERS

Plan B

Schedule JJC-5

Derivation of Utility Unit Cost to achieve Annual KWh Saveing (Eversource as proxy, excl PI):

Forecast for 2015-2026:		Amount	
2015 Escalation at 2.5%	$	0.378	
2016 Escalation at 2.5%	$	0.416	(1)
2017 Escalation at 2.5%	$	0.427	
2018 Escalation at 2.5%	$	0.437	
2019 Escalation at 2.5%	$	0.448	
2020 Escalation at 2.5%	$	0.459	
2021 Escalation at 2.5%	$	0.471	
2022 Escalation at 2.5%	$	0.483	
2023 Escalation at 2.5%	$	0.495	
2024 Escalation at 2.5%	$	0.507	
2025 Escalation at 2.5%	$	0.520	
2026 Escalation at 2.5%	$	0.533	

Footnotes:

(1) Calculation of 2016 Utility Unit Cost (Eversource):

	2014 Actual	Average in 2016 Price Levels: 2015 Core	2016 Core	Average
Utility Cost (excl PI)	$ 19,113,200	$ 18,424,500	$ 17,486,600	
Annual kWh Saving	51,888,800	43,528,700	40,882,600	
Unit Cost per kWh	$ 0.368	$ 0.42	$ 0.428	
2015 - Escal at 1.025	$ 0.378			
2016 - Escal at 1.025	$ 0.387	$ 0.434	$ 0.428	$ 0.416

Comparison to Cost to Achieve kWh Savings in New England States:
Lifetime Basis:

		Year 2013
ME	$	0.0200
NH	$	0.0310
VT	$	0.0320
MA	$	0.0350
RI	$	0.0370
CT	$	0.0400

Source: DE 15-248, PSNH Least Cost Integrated Resource Plan, June 19, 2015, p. 22.

DE 15-137 **Plan B** Schedule JJC-6

EERS

Derivation of Estimated Retirement of Prior EE Installations

Lifetime Sav		Annual Retirements					Retirement kWh Assume 50% Replace with Std. EE
		Core	Co. Specific	Lifetime Savings Life Savings	Life (Years)	Annual Savings	
					(1)		(2)
Year Installed	Year Retired						
2003	2017			1,368,000,000	14.30	95,691,012	47,845,506
2004	2018	851,633,400	78,242,775	929,876,175	14.30	65,044,439	32,522,220
2005	2019	972,035,330	49,795,874	1,021,831,204	14.30	71,476,654	35,738,327
2006	2020	934,721,338	38,009,365	972,730,703	14.30	68,042,095	34,021,047
2007	2021	925,977,328	63,682,413	989,659,741	14.30	69,226,274	34,613,137
2008	2022	749,773,432	65,109,047	814,882,479	14.30	57,000,679	28,500,340
2009	2023	739,944,852	66,415,502	806,360,354	14.30	56,404,560	28,202,280
2010	2024	728,397,258	65,086,500	793,483,758	14.30	55,503,848	27,751,924
2011	2025	684,593,766	70,307,829	754,901,595	14.30	52,805,042	26,402,521
2012	2026	668,386,293	46,499,357	714,885,650	14.30	50,005,944	25,002,972

footnotes:

(1) Based on 3-year average (Sch. 7): 14.30

(2) It is difficult to project future customer purchase of standard vs. high efficiency equipment; therefore, a discount factor of 50% is applied.

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EERS
Data for Calculation of Benefit Cost (BC) Ratios

Plan B

Schedule JJC-7

	2014 Actual (final)		2015 Core		2016 Core		Average	
Ratio of Equiv to Pure kWh (Eversource):								
Electric annual kWh Savings		51,888,800		43,528,700		40,882,600		45,433,367
Annual MMBtu Savings	69,186		28,337		39,100		45,541	
kWh factor	293	20,271,498	293	8,302,741	293	11,456,241	293	13,343,493
Equiv kWh Savings		72,160,298		51,831,441		52,338,841		58,776,860
Factor for Equiv. kWh		1.39		1.19		1.28		1.29
Measure Life (Eversource):								
Electric lifetime kWh Savings		694,571,000		565,700,800		553,930,600		604,734,133
Lifetime MMBtu Savings	1,132,264		575,524		703,891		803,893	
kWh Factor	293	331,753,352	293	168,628,473	293	206,240,122	293	235,540,649
Equiv kWh Savings		1,026,324,352		734,329,273		760,170,722		840,274,782
Annual Equivalent kWh Savings		72,160,298		51,831,441		52,338,841		58,776,860
Measure Life		14.2		14.2		14.5		14.30
Benefits per equivalent lifetime kWh saved (Eversource):								
Benefit Dollars		$ 86,016,400		$ 62,033,700		$ 63,310,100		$ 70,453,400
Lifetime Equivalent kWh savings		1,026,324,352		734,329,273		760,170,722		840,274,782
Rate per kWh		$ 0.084		$ 0.084		$ 0.083		$ 0.084
Customer Cost Factor (Eversource):								
"Customer" Cost		$ 16,649,700		$ 13,285,100		$ 10,938,600		$ 13,624,467
"Utility" Cost Incl. PI at 7.5%	$ 19,113,200	$ 20,546,690	$ 18,424,500	$ 19,806,338	$ 17,486,600	$ 18,798,095	18,341,433	19,717,041
"Installed" Cost		$ 37,196,390		$ 33,091,438		$ 29,736,695		$ 33,341,508
Installed Cost Factor		$ 1.81		$ 1.67		$ 1.58		$ 1.69

EERS

EERS Savings Targets

Plan B

Schedule JJC-8

EERS Comparisons Annual kWh Savings as % of Load (1)							EERS Planned Savings or New Hampshire	
							Short-Term	Long-Term
Industry	Year	ME	VT (2)	RI	CT	MA	Year 2019	Year 2026
Electricity	2014	1.6%	2.0%	2.5%	1.4%	2.5%	0.8%	2.9%
	2015	1.6%	2.0%		1.4%	2.6%		

Footnotes:

(1) Source: ACEEE, *Energy Efficiency Resource Standards*, April, 2014.
(2) Includes demand response targets.

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Plan B

Schedule JJC-9

EERS

Summary of PI and Lost Revenue Impacts for certain years

		Utility Spending	PI	Pecent of Util Spending	Percent of Utility Sales $
Year 2014 Actual:		*Final PI Report*			$ 1,333,326,584
PI	Eversource	$ 19,113,200	$ 1,755,017	9.2%	
	Liberty	$ 2,168,000	$ 196,915	9.1%	
	Unitil	$ 2,760,000	$ 261,415	9.5%	
	NHEC	$ 1,839,500	$ 159,125	8.7%	
	Total	$ 25,880,700	$ 2,372,472	9.2%	0.2%
Year 2017 Est:		*Schedule 2*			$ 1,435,846,898
PI			$ 2,604,411	10.0%	
Lost Rev			$ -		
Total		$ 26,044,113	$ 2,604,411	10.0%	0.2%
Year 2018 Est:		*Schedule 2*			$ 1,471,743,071
PI			$ 3,150,036		
Lost Rev			$ -		
Total		$ 31,500,355	$ 3,150,036	10.0%	0.2%
Year 2019 Est:		*Schedule 2*			$ 1,508,536,648
PI			$ 3,874,544		
Lost Rev			$ 1,988,618		
Total		$ 38,745,437	$ 5,863,161	15.1%	0.4%
Year 2020		*Schedule 2*			
PI			$ 4,765,689		$ 1,546,250,064
Lost Rev			$ 5,255,756		
Total		$ 47,656,887	$ 10,021,445	21.0%	0.6%
Year 2021		*Schedule 2*			
PI			$ 5,861,797		$ 1,584,906,315
Lost Rev			$ 7,924,532		
Total		$ 58,617,972	$ 13,786,329	23.5%	0.9%
Year 2022		*Schedule 2*			
PI			$ 7,210,010		$ 1,624,528,973
Lost Rev			$ 8,122,645		
Total		$ 72,100,105	$ 15,332,655	21.3%	0.9%
Year 2023		*Schedule 2*			$ 1,665,142,198
PI			$ 8,868,313		
Lost Rev			$ 8,325,711		
Total		$ 88,683,129	$ 17,194,024	19.4%	1.0%
Year 2024		*Schedule 2*			$ 1,706,770,753
PI			$ 10,908,025		
Lost Rev			$ 8,533,854		
Total		$ 109,080,249	$ 19,441,879	17.8%	1.1%
Year 2025		*Schedule 2*			$ 1,749,440,021
PI			$ 13,416,871		
Lost Rev			$ 8,747,200		
Total		$ 134,168,706	$ 22,164,071	16.5%	1.3%
Year 2026		*Schedule 2*			$ 1,793,176,022
PI			$ 16,502,751		
Lost Rev			$ 8,965,880		
Total		$ 165,027,508	$ 25,468,631	15.4%	1.4%
Note #1:	LR (2019-2026)		$ 57,864,195		
	Util. Spending (2019-2026)		$ 714,079,993		
	Percentage		8%		
Note #2:	PI + LR (2019-2026)		$ 129,272,194		
	Util. Spending 2019-2026)		$ 714,079,993		
	Percentage		18%		

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EERS

Attachment 2

Annual State EERS Targets

Gas Utilities: Plan A

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EERS
Gas - MMBtu Savings Targets

Plan A

Schedule JJC-1

Gas MMBtu Savings Summary						
			Annual Savings		Cumulative Savings	
Year	Description	Percent Year-To-Year kWh Saving Increase	MMBtu	Percent to 2014 MMBtu Sales (1)	MMBtu	Percent to 2014 MMBtu Sales
2014	Act. MMBtu Saving		150,197	0.60%		
2015	Approved Core		140,963	0.57%		
2016	Proposed Core Upd.		152,492	0.61%		
2017	Short-Term	7.00%	163,166	0.66%	163,166	0.66%
2018	Short-Term	8.00%	176,220	0.71%	339,386	1.37%
2019	Short-Term	9.00%	192,080	0.77%	531,466	2.14%
2020	Long-Term	10.00%	211,287	0.85%	742,753	2.99%
2021	Long-Term	10.00%	232,416	0.93%	975,169	3.92%
2022	Long-Term	10.00%	255,658	1.03%	1,230,827	4.95%
2023	Long-Term	10.00%	281,224	1.13%	1,512,051	6.08%
2024	Long-Term	10.00%	309,346	1.24%	1,821,397	7.33%
2025	Long-Term	10.00%	340,281	1.37%	2,161,678	8.69%
2026	Long-Term	10.00%	374,309	1.51%	2,535,986	10.20%
	(1) Actual MMBtu sales for year 2014 are used for measurement purposes				24,862,611	

EERS **Plan A** Schedule JJC-1A

MMBtu Savings Details - Gas Utilities

Description	Year	2014 Starting Points	% Annual Savings to 2014 Usage	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
				Cumulative Savings Targets By End of Each Forecast Year									
Annual Savings	2014 Actual	150,197	0.60%										
	2015 Core	140,963	0.57%										
	2016 Core	152,492	0.61%										
EERS	2017	163,166	0.66%	163,166	163,166	163,166	163,166	163,166	163,166	163,166	163,166	163,166	163,166
EERS	2018	176,220	0.71%		176,220	176,220	176,220	176,220	176,220	176,220	176,220	176,220	176,220
EERS	2019	192,080	0.77%			192,080	192,080	192,080	192,080	192,080	192,080	192,080	192,080
EERS	2020	211,287	0.85%				211,287	211,287	211,287	211,287	211,287	211,287	211,287
EERS	2021	232,416	0.93%					232,416	232,416	232,416	232,416	232,416	232,416
EERS	2022	255,658	1.03%						255,658	255,658	255,658	255,658	255,658
EERS	2023	281,224	1.13%							281,224	281,224	281,224	281,224
EERS	2024	309,346	1.24%								309,346	309,346	309,346
EERS	2025	340,281	1.37%									340,281	340,281
EERS	2026	374,309	1.51%										374,309
Cumulative Savings			*ACEEE-EERS*	163,166	339,386	531,466	742,753	975,169	1,230,827	1,512,051	1,821,397	2,161,678	2,535,986
% Cumulative Savings to 2014 Actual Usage			*ramps up to new sav of 1.5% of prior yr sales*	0.66%	1.37%	2.14%	2.99%	3.92%	4.95%	6.08%	7.33%	8.69%	10.20%
								VEIC=1.75 (Equiv in 5 years					*GDS=10.8% (Pot Obtain in 10 yrs)*

Comments:

1. Annual savings in 2019 achieves 0.8% of 2014 actual usage, in line with other New England states.
2. Cumulative savings by 2021 achieves 3.92% of 2014 actual usage, versus VEIC's November 2013 Report of 1.7%.
3. Cumulative savings by 2026 achieve 10.2% of 2014 actual usage, versus GDS' January 2009 Report of 10.8%.
4. 2014 Actual MMBtu Usage for the two NH utilities. 24,862,611

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EERS
Gas - Spending Targets

Plan A

Schedule JJC-2

Year	Description	Spending Summary: Annual Saving MMBtu (1)	Unit Cost To Achieve MMBtu Sav. (2)	Utility Cost Excluding PI Excl. Lost Rev.	Plus: EESE Consult. (3)	Plus: Est. Perm. EESE Brd. (4)	Plus: Est. TRM Costs (5)	Plus: PI (6)	Plus: Lost Rev (7)	Total	LDAC: Calc. Rate (8)	LDAC: Excess/Short. From Existing $0.0291/Therm
2014	Actual	150,197		$ 6,480,979				$ 575,924	$ -	$ 7,056,903	$ 0.0284	
2015	Core Filing	140,963		$ 6,728,741				$ 605,587	$ -	$ 7,334,328	$ 0.0288	
2016	Core Filing	152,492	$ 45.70	$ 6,969,462				$ 627,252	$ -	$ 7,596,714	$ 0.0291	$ -
2017	Short-Term	163,166	$ 47.82	$ 7,802,874	$ 100,000			$ 780,287	$ -	$ 8,683,162	$ 0.0324	$ (1,086,448)
2018	Short-Term	176,220	$ 49.02	$ 8,637,782	$ 102,500			$ 863,778	$ -	$ 9,604,060	$ 0.0350	$ (2,007,346)
2019	Short-Term	192,080	$ 50.24	$ 9,650,562	$ 105,063			$ 965,056	$ -	$ 10,720,680	$ 0.0381	$ (3,123,967)
2020	Long-Term	211,287	$ 51.50	$ 10,881,008	$ 107,689	$ 1,000,000	$ 500,000	$ 1,088,101	$ -	$ 13,576,798	$ 0.0471	$ (5,980,085)
2021	Long-Term	232,416	$ 52.79	$ 12,268,337	$ 110,381	$ 1,025,000	$ 250,000	$ 1,226,834	$ 33,015	$ 14,913,567	$ 0.0505	$ (7,316,853)
2022	Long-Term	255,658	$ 54.11	$ 13,832,550	$ 113,141	$ 1,050,625	$ 256,250	$ 1,383,255	$ 265,307	$ 16,901,128	$ 0.0558	$ (9,304,414)
2023	Long-Term	281,224	$ 55.46	$ 15,596,200	$ 115,969	$ 1,076,891	$ 262,656	$ 1,559,620	$ 271,940	$ 18,883,276	$ 0.0608	$ (11,286,563)
2024	Long-Term	309,346	$ 56.84	$ 17,584,715	$ 118,869	$ 1,103,813	$ 269,223	$ 1,758,472	$ 278,738	$ 21,113,830	$ 0.0663	$ (13,517,116)
2025	Long-Term	340,281	$ 58.27	$ 19,826,767	$ 121,840	$ 1,131,408	$ 275,953	$ 1,982,677	$ 285,707	$ 23,624,352	$ 0.0724	$ (16,027,638)
2026	Long-Term	374,309	$ 59.72	$ 22,354,679	$ 124,886	$ 1,159,693	$ 282,852	$ 2,235,468	$ 292,850	$ 26,450,429	$ 0.0791	$ (18,853,715)
										$ 29,007,902		

(1) Annual Savings: targets for annual savings are shown on Schedule 1.
(2) Unit Cost: Gas Industry average of 2014-2016 in then year dollars, with 2.5% annual escalation See Appendix A.
(3) Estimated amount to provide a placeholder for an administrative resource to assist permanent EESE Board.
(4) Estimated amount to provide a placeholder for estimated cost of permanent EESE Board.
(5) Estimated amount to provide a placeholder for estimated cost of TRM.
(6) PI and LR: Adjust PI cap to 10%, same as electric PI and retain as LR is introduced.
(7) Lost Revenue (LR): Lost revenues reflect "incremental" and "retirement" and "fuel-switching" adjustment (Sch 3).
(8) LDAC Rates: Calculated with actual 2014 Therm sales per 2014 Annual Report plus 2.5% growth per year:

2014 Therms	2015 Therms	2016 Therms	2017 Therms	2018 Therms	2019 Therms	2020 Therms	2021 Therms	2022 Therms	2023 Therms	2024 Therms	2025 Therms	2026 Therms
248,625,510	254,841,148	261,212,176	267,742,481	274,436,043	281,296,944	288,329 368	295,537,602	302,926,042	310,499,193	318,261,673	326,218,214	334,373,670

DE 15-137
EERS
Gas - Lost Revenue

Plan A

Schedule JJC-3

Year	Description	Annual MMBtu Saving Est.	Adjustment For Increment (1)	Adjust For Retirement (2)	Fuel Switching (3)	Adjusted Annual Savings	Cumulative MMBtu Savings for LR	Estimated LR $/MMBtu (4)	Amount (Not < $0)	Cap (4)	Total LR Lower of Calc or Cap (Not > Cap)
		Annual MMBtu Savings for Lost Rev.						Lost Revenue Amount			
2014	Actual	150,197									
2015	Approved Core	140,963							$ -		
2016	Approved Core	152,492							$ -		
									$ -		
2017	Short-Term	163,166	(147,884)	(16,978)	(138,486)	(140,182)	(140,182)	$ 3.503	$ -	$ 234,493	$ -
2018	Short-Term	176,220	-	(16,978)	(141,949)	17,293	(122,889)	$ 3.591	$ -	$ 240,355	$ -
2019	Short-Term	192,080	-	(16,978)	(145,497)	29,604	(93,285)	$ 3.681	$ -	$ 246,364	$ -
2020	Long-Term	211,287	-	(16,978)	(149,135)	45,175	(48,110)	$ 3.773	$ -	$ 252,523	$ -
2021	Long-Term	232,416	-	(22,906)	(152,863)	56,647	8,538	$ 3.867	$ 33,015	$ 258,836	$ 33,015
2022	Long-Term	255,658	-	(34,574)	(156,685)	64,399	72,937	$ 3.964	$ 289,095	$ 265,307	$ 265,307
2023	Long-Term	281,224	-	(38,165)	(160,602)	82,457	155,394	$ 4.063	$ 631,322	$ 271,940	$ 271,940
2024	Long-Term	309,346	-	(72,611)	(164,617)	72,118	227,512	$ 4.164	$ 947,425	$ 278,738	$ 278,738
2025	Long-Term	340,281	-	(37,115)	(168,732)	134,434	361,946	$ 4.268	$ 1,544,926	$ 285,707	$ 285,707
2026	Long-Term	374,309	-	(55,479)	(172,951)	145,879	507,825	$ 4.375	$ 2,221,783	$ 292,850	$ 292,850

Footnotes:

(1) Projected LR is reduced to reflect "incremental" savings levels in order to remove average 2014-2016 savings levels which were achieved without LR.

(2) Projected LR is based on reduced MMBtu savings to reflect prior installed savings that are "retired" during 2017-2026. See Schedule 6.

(3) Source: Schedule JJC-6A, DR Staff 3-7, Staff 3-8, Staff 3-9, Staff 3-10, Docket DE 14-216.

(4) Illustration of LR $/MMBtu is estimated using base rates from the 2014 annual reports from Energy North and Northern as follows:

	Actual Year 2014	Estimate Year 2015	Estimate Year 2016	Estimate Year 2017
2014 Act. Base Dist Rev. ($55.9m+$31.2m=$87.1m) + 2.5% Escal.	$ 87,100,000	$ 89,277,500	$ 91,509,438	$ 93,797,173
2014 Actual MMBtu Sales, with est. 2.5% Growth	24,862,511	25,484,074	26,121,176	26,774,205
Est. Base Rate Revenue per MMBtu	$ 3.503	$ 3.503	$ 3.503	$ 3.503

(5) Derivation of Net Lost Revenue Cap:

	Year 2017	Year 2018	Year 2019	Year 2020	Year 2021	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Rev.	$ 93,797,173	$ 96,142,103	$ 98,545,655	$ 101,009,297	$ 103,534,529	$ 106,122,892	$ 108,775,965	$ 111,495,364	$ 114,282,748	$ 117,139,817
Cap%	$ 0.0025	$ 0.0025	$ 0.0025	$ 0.0025	$ 0.0025	$ 0.0025	$ 0.0025	$ 0.0025	$ 0.0025	$ 0.0025
Cap	$ 234,493	$ 240,355	$ 246,364	$ 252,523	$ 258,836	$ 265,307	$ 271,940	$ 278,738	$ 285,707	$ 292,850

DE 15-137
EERS
Gas - Details of Benefit & Costs

Plan A

Schedule JJC-4

	Benefits					Costs			
Year	Annual Pure MMBtu Savings	Annual Equivalent MMBtu Savings (1)	Lifetime Equiv. MMBtu Savings (2)	Benefits Per MMBtu	NPV Benefits 1.36% Disc. Rate (3)	Utility Cost (Incl. PI & LR)	Util+Cust "Installed" Cost (4)	NPV Costs 2.5% Disc. Rate	B/C
2017	163,166	163,650	2,348,611	$ 18,961,456	$ 18,961,456	$ 8,683,162	$ 12,962,020	$ 12,962,020	1.46
2018	176,220	176,742	2,536,500	$ 20,756,878	$ 20,478,372	$ 9,604,060	$ 14,336,716	$ 13,987,040	1.46
2019	192,080	192,649	2,764,785	$ 22,932,697	$ 22,321,426	$ 10,720,680	$ 16,003,581	$ 15,232,439	1.47
2020	211,287	211,914	3,041,264	$ 25,569,040	$ 24,553,568	$ 13,576,798	$ 20,267,127	$ 16,403,670	1.50
2021	232,416	233,105	3,345,390	$ 28,508,457	$ 27,008,925	$ 14,913,567	$ 22,262,623	$ 18,106,583	1.49
2022	255,658	256,415	3,679,929	$ 31,785,789	$ 33,100,366	$ 16,901,128	$ 25,229,608	$ 20,485,936	1.62
2023	281,224	282,057	4,047,922	$ 35,439,883	$ 32,680,799	$ 18,883,276	$ 28,188,512	$ 23,757,406	1.38
2024	309,346	310,263	4,452,715	$ 39,514,052	$ 35,945,333	$ 21,113,830	$ 31,518,230	$ 28,240,090	1.27
2025	340,281	341,289	4,897,986	$ 44,056,588	$ 39,543,767	$ 23,624,352	$ 35,265,880	$ 34,407,807	1.15
2026	374,309	375,418	5,387,785	$ 49,121,333	$ 43,498,144	$ 26,450,429	$ 39,484,581	$ 42,970,636	1.01

footnotes:

(1) Factor for equivalent MMBtu saved, based on 3-year average (2014-2016)	1.00	See Sch. 7
(2) Est. average lifetime for equivalent savings, based on 3-year average (2014-2016)	14.4	See Sch. 7
(3) Est. value of benefits/lifetime MMBtu, based on 3-year average (2014-2016)	$ 8.073	See Sch. 7
(4) Estimated installed cost based on 3-year average (2014-2016).	1.49	See Sch 7

Plan A

Gas - Derivation of Utility Unit Cost per Annual MMBtu Saved:

Forecast for 2016-2026:	Unit Cost to Achieve Ann. MMBtu Savings	LDAC Rate Calculation
2016 Escalation at 2.5%	$ 46.66 (1)	$ 0.026 (2)
2017 Escalation at 2.5%	$ 47.82	$ 0.026
2018 Escalation at 2.5%	$ 49.02	$ 0.026
2019 Escalation at 2.5%	$ 50.24	$ 0.026
2020 Escalation at 2.5%	$ 51.50	$ 0.026
2021 Escalation at 2.5%	$ 52.79	$ 0.026
2022 Escalation at 2.5%	$ 54.11	$ 0.026
2023 Escalation at 2.5%	$ 55.46	$ 0.026
2024 Escalation at 2.5%	$ 56.84	$ 0.026
2025 Escalation at 2.5%	$ 58.27	$ 0.026
2026 Escalation at 2.5%	$ 59.72	$ 0.026

Footnotes:

(1) Calculation of Cost to achieve Annual Savings - Average cost per MMBtu to achieve Savings:

	2014 Actual	2015 Core	2016 Core	Average
Utility Cost (Excl PI)	$ 6,480,979	$ 6,728,741	$ 6,969,462	$ 6,726,394
Annual MMBtu Savings	150,197	140,963	152,492	147,884
Unit Cost per Annual MMBtu	$ 43.15	$ 47.73	$ 45.70	$ 45.48
2015 - Escal at 1.025	$ 44.23			
2016 - Escal at 1.025	$ 45.33	$ 48.93	$ 45.70	$ 46.66

		Final PI Filing
Spending	Northern	$ 1,167,000.0
	Energy North	$ 5,313,979.0
		$ 6,480,979.0

(2) Calculation of LDAC Rate per Therm (assumes Cost and therm sales increase at 2.5% per year):

	2014 Actual	2015 Estimate	2016 Estimate
Utility Cost	$ 6,480,979	$ 6,728,741	$ 6,896,960
Annual Therm Sales	248,625,110	254,840,738	261,211,756
LDAC Rate Per Therm	$ 0.026	$ 0.026	$ 0.026
Percent EE Spending to Sales Rev Dollars			
EE Spending	$ 6,480,979	$ 6,728,741	$ 6,969,462
Distribution Sales Revenue Dollars	$ 218,048,410	$ 223,499,620	$ 229,087,111
Percent Utility Cost to Sales Rev. Dollars	3%	3%	3%
Percent MMBtu Savings to MMBtu Usage:			
MMBtu Savings	150,197	140,963	152,492
MMBtu Usage	24,862,511	25,484,074	26,121,176
% Savings	0.6%	0.6%	0.6%

DE 15-137

EERS

Gas - Derivation of Estimated Retirement of Prior EE Installations

Plan A

Schedule JJC-6

Lifetime Sav			Reported Core Savings / Retirements			Retirement MMBtu Discounted by 50 Percent
			Lifetime MMBtu Savings	Est. Life (Years)	Est. Annual Savings	
			(1)	(2)		(2)
Year Installed	Year Retired					
2001 (1)	2017	Liberty	349,226			
		Unitil	138,092			
		Total	487,318	14.4	33,956	16,978
2002 (1)	2018	Liberty	349,226			
		Unitil	138,092			
		Total	487,318	14.4	33,956	16,978
2003 (1)	2019	Liberty	349,226	14.4	24,334	
		Unitil	138,092	14.4	9,622	
		Total	487,318		33,956	16,978
2004	2020	Liberty	349,226	14.4	24,334	
		Unitil	138,092	14.4	9,622	
		Total	487,318		33,956	16,978
2005	2021	Liberty	507,395	14.4	35,355	
		Unitil	150,066	14.4	10,457	
		Total	657,461		45,812	22,906
2006	2022	Liberty	678,085	14.4	47,249	
		Unitil	314,287	14.4	21,899	
		Total	992,372		69,148	34,574
2007	2023	Liberty	840,437	14.4	58,561	
		Unitil	254,997	14.4	17,768	
		Total	1,095,434		76,329	38,165
2008	2024	Liberty	1,862,102	14.4	129,750	
		Unitil	222,052	14.4	15,472	
		Total	2,084,154		145,223	72,611
2009	2025	Liberty	858,374	14.4	59,811	
		Unitil	206,927	14.4	14,419	
		Total	1,065,301		74,230	37,115
2010	2026	Liberty	1,226,114	14.4	85,435	
		Unitil	366,302	14.4	25,524	
		Total	1,592,416		110,959	55,479

footnotes:

(1) Reflects 2004 data as a proxy.

(2) Based on 3-year average 2014-2016 — 14.4

(3) It is difficult to project future customer purchase of standard vs. high efficiency equipment, therefore a discount of 50 percent is applied.

DE 15-137
EERS-Gas-Lost Revenues
Fuel Switching - Estimate for 2017

Schedule JJC 6A

Description:		Liberty-Gas - 2017 Residential	Liberty-Gas - 2017 C&I	Liberty-Gas - 2017 Total	Unitil-Gas - 2017 Residential	Unitil-Gas - 2017 C&I	Unitil-Gas - 2017 Total	Annual Therms Fuel Switch
New Customers:								
No. of new customers (3)		311	70		980	406		
Less: new Res. Cust. (above) constructing new homes (?)		-	-		-	-		
Sub-Total		311	70		980	406		
Annual Equivalent Conversion % (12/10 for Liberty; 12/21 for Unitil)		120%	120%		57%	57%		
Estimated Annual Equivalent No. of new customers		373	84		559	231		
Estimated % conversions from oil or other fossil fuel heat		100%	100%		51%	51%		
No. new customers - oil/other fossil to natural gas		311	84		285	118		
Existing Customers:								
Existing customers switching to natural gas					54	24		
Annual Equivalent Conversion % (12/21)					57%	57%		
Estimated Annual Equivalent No. of existing customers		incl. above	incl. above		31	14		
Total New and Existing		311	84		316	132		
Average annual therm usage (2)		776	4,176		769	4,176		
Extended Therms	(1)	241,336	350,784		242,747	549,997		
Conversion to MMBtu (Therms divided by 10)	(2)	24,134	35,078	59,212	24,275	55,000	79,274	138,486

footnotes:
(1) Liberty-Gas EE participants that switched from oil/other fossil to gas; Unitil-Gas does not track fuel conversions; but indicates majority of new customers converted.
(2) Used Liberty-Gas' estimate of average annual non-residential usage for both Liberty and Unitl for this calculation.
(3) Source: Data Responses in Ccre 2016 Update Docket DE 14-216: Staff 3-7 and Staff 3-8 (Unitil-Gas); and, Staff 3-9 and Staff 3-10 (Liberty-Gas).

DE 15-137
EERS
Gas - Average 2014-2016 Data

Plan A

Schedule JJC-7

Description	2014 Actual (final)		2015 Core		2016 Core Update		Average 2014-2016	
Ratio of Equiv to Pure kWh (Liberty/Unitil Gas):								
Gas annual MMBtu Savings		150,197		140,963		152,492		147,884
kWh Savings	101,614		283,486		46		128,382	
Conversion Factor - kWh to MMBtu	293	347	293	968	293	0	293	438.16
MMBtu Savings		150,544		141,931		152,492		148,322
Factor for Equiv. kWh		1.002		1.007		1.000		1.003
Measure Life:								
Lifetime MMBtu Savings		1,757,567		2,236,530		2,372,948		2,122,348
Annual MMBtu Savings		150,197		140,963		152,492		147,884
Est. Measure Life		11.7		15.9		15.6		14.4
Benefits per lifetime MMBtu saved:								
Benefit Dollars		$ 17,698,178		$ 16,065,000		$ 17,641,000		17,134,726
Lifetime MMBtu Savings		1,757,567		2,236,530		2,372,948		2,122,348
Rate per Equiv. MMBtu		10.07		7.18		7.43		$ 8.07
Customer Cost Factor								
"Customer Cost"		$ 2,646,515		$ 3,695,000		$ 4,348,000		3,563,172
"Utility" Cost Incl. PI and LR at est. 7.5%	$ 6,480,789	$ 6,966,848	$ 6,728,741	$ 7,233,397	$ 6,969,462	$ 7,492,172	$ 6,726,331	7,230,805
"Installed" Cost		$ 9,613,363		$ 10,928,397		$ 11,840,172		10,793,977
Installed Cost Factor / Utility Cost		1.38		1.51		1.58		1.49

R156

EERS

EERS Savings Targets

Gas Industries

Plan A

Schedule JJC-8

EERS Targets
MMBtu Savings as % of Load (1)

Industry	Year	ME	VT	RI	CT (2)	MA	NH
Gas	2014	0.30%		1.00%	0.30%	1.10%	0.60%
	2015	0.30%			0.30%	1.15%	0.57%
	2016	0.30%					0.61%
	2017						0.66%
	2018						0.71%
	2019						0.77%

Footnotes:

(1) Source: ACEEE, *Energy Efficiency Resource Standards*, April, 2014 for all states.
(2) CT Draft Decision, August 23, 2013, page 20 (gas).

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EERS
Gas - Summary of PI and Lost Revenue Impacts for certain years

Plan A

Schedule JJC-9

		Spending	PI	% of Spending	% of Base Dist. Sales Rev
Year 2014 Actual:					$ 87,100,000
PI	Liberty Gas				
	Unitil Gas				
	Total	$ 6,966,848	$ 575,924	8.3%	0.7%
Year 2017 Est:					$ 93,797,173
PI			$ 780,287	10.0%	
Lost Rev			$ -		
Total		$ 7,802,874	$ 780,287	10.0%	0.8%
Year 2018 Est:					$ 96,142,103
PI			$ 863,778		
Lost Rev			$ -		
Total		$ 8,637,782	$ 863,778	10.0%	0.9%
Year 2019 Est:					$ 98,545,655
PI			$ 965,056		
Lost Rev			$ -		
Total		$ 9,650,562	$ 965,056	10.0%	1.0%
Year 2020					
PI			$ 1,088,101		$ 101,009,297
Lost Rev			$ -		
Total		$ 10,881,008	$ 1,088,101	10.0%	1.1%
Year 2021					
PI			$ 1,226,834		$ 103,534,529
Lost Rev			$ 33,015		
Total		$ 12,268,337	$ 1,259,848	10.3%	1.2%
Year 2022					
PI			$ 1,383,255		$ 106,122,892
Lost Rev			$ 265,307		
Total		$ 13,832,550	$ 1,648,562	11.9%	1.6%
Year 2023					$ 108,775,965
PI			$ 1,559,620		
Lost Rev			$ 271,940		
Total		$ 15,596,200	$ 1,831,560	11.7%	1.7%
Year 2024					$ 111,495,364
PI			$ 1,758,472		
Lost Rev			$ 278,738		
Total		$ 17,584,715	$ 2,037,210	11.6%	1.8%
Year 2025					$ 114,282,748
PI			$ 1,982,677		
Lost Rev			$ 285,707		
Total		$ 19,826,767	$ 2,268,384	11.4%	2.0%
Year 2026					$ 117,139,817
PI			$ 2,235,468		
Lost Rev			$ 292,850		
Total		$ 22,354,679	$ 2,528,317	11.3%	2.2%

PI (2018-2026)	$ 13,063,260
LR (2018-2026)	$ 1,427,557
Total	$ 130,632,600
Percent	11.1%

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EERS

Attachment 2

Annual State EERS Targets

Gas Utilities: Plan B

DE 15-137

EERS

Gas - MMBtu Savings Targets

Plan B

Schedule JJC-1

Gas MMBtu Savings Summary						
		Percent	Annual Savings		Cumulative Savings	
Year	Description	Year-To-Year kWh Saving Increase	MMBtu	Percent to 2014 MMBtu Sales (1)	MMBtu	Percent to 2014 MMBtu Sales
2014	Act. MMBtu Saving		150,197	0.60%		
2015	Approved Core		140,963	0.57%		
2016	Proposed Core Upd.		152,492	0.61%		
2017	Short-Term	13.00%	172,316	0.69%	172,316	0.69%
2018	Short-Term	14.00%	196,440	0.79%	368,756	1.48%
2019	Short-Term	15.00%	225,906	0.91%	594,662	2.39%
2020	Long-Term	15.00%	259,792	1.04%	854,455	3.44%
2021	Long-Term	15.00%	298,761	1.20%	1,153,216	4.64%
2022	Long-Term	15.00%	343,575	1.38%	1,496,791	6.02%
2023	Long-Term	15.00%	395,111	1.59%	1,891,902	7.61%
2024	Long-Term	15.00%	454,378	1.83%	2,346,280	9.44%
2025	Long-Term	15.00%	522,535	2.10%	2,868,815	11.54%
2026	Long-Term	15.00%	600,915	2.42%	3,469,730	13.96%
	(1) Actual MMBtu sales for year 2014 are used for measurement purposes				24,862,611	

EERS

MMBtu Savings Details - Gas Utilities

Plan B

Schedule JJC-1A

Description	Year	2014 Starting Points	% Annual Savings to 2014 Usage	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
				Cumulative Savings Targets By End of Each Forecast Year									
Annual Savings	2014 Actual	150,197	0.60%										
	2015 Core	140,963	0.57%										
	2016 Core	152,492	0.61%										
EERS	2017	172,316	0.69%	172,316	172,316	172,316	172,316	172,316	172,316	172,316	172,316	172,316	172,316
EERS	2018	196,440	0.79%		196,440	196,440	196,440	196,440	196,440	196,440	196,440	196,440	196,440
EERS	2019	225,906	0.91%			225,906	225,906	225,906	225,906	225,906	225,906	225,906	225,906
EERS	2020	259,792	1.04%				259,792	259,792	259,792	259,792	259,792	259,792	259,792
EERS	2021	298,761	1.20%					298,761	298,761	298,761	298,761	298,761	298,761
EERS	2022	343,575	1.38%						343,575	343,575	343,575	343,575	343,575
EERS	2023	395,111	1.59%							395,111	395,111	395,111	395,111
EERS	2024	454,378	1.83%								454,378	454,378	454,378
EERS	2025	522,535	2.10%									522,535	522,535
EERS	2026	600,915	2.42%										600,915
Cumulative Savings			*ACEEE-EERS ramps up to new sav of 1.5% of prior yr sales*	172,316	368,756	594,662	854,455	1,153,216	1,496,791	1,891,902	2,346,280	2,868,815	3,469,730
% Cumulative Savings to 2014 Actual Usage				0.69%	1.48%	2.39%	3.44%	4.64%	6.02%	7.61%	9.44%	11.54%	13.96%
								VEIC=1.75					*GDS=20 5%*
								(Equiv in 5 years					*(MACE in 10 yrs)*

Comments:

1. Annual savings in 2019 achieves 0.91% of 2014 actual usage, in line with other New England states.
2. Cumulative savings by 2021 achieve 4.64% of 2014 actual usage, versus VEIC's November 2013 Report of 1.75%.
3. Cumulative savings by 2026 achieve 13.96% of 2014 actual usage, versus GDS' January 2009 Report of 10.8% for potentially obtainable.
4. 2014 Actual MMBtu Usage for the two NH utilities. 24 862,611

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EERS
Gas - Spending Targets

Plan B

Schedule JJC-2

Year	Description	Annual Saving MMBtu (1)	Unit Cost To Achieve MMBtu Sav. (2)	Utility Cost Excluding PI Excl. Lost Rev.	Plus: EESE Consult. (3)	Plus: Est. Perm. EESE Board (4)	Plus: Est. TRM Costs (5)	Plus: PI (6)	Plus: Lost Rev (7)	Total	Calculated LDAC Rate Per Therm (8)	LDAC Excess/(Short) From Existing $0.0291/Therm
					Spending Summary							
2014	Actual	150,197		$ 6,480,979				$ 575,924	$ -	$ 7,056,903	$ 0.0284	
2015	Core Filing	140,963		$ 6,728,741				$ 605,587		$ 7,334,328	$ 0.0288	
2016	Core Filing	152,492	$ 45.70	$ 6,969,462				$ 627,251.58		$ 7,596,714	$ 0.0291	
2017	Short-Term	172,316	$ 47.82	$ 8,240,419	$ 100,000			$ 824,042	$ -	$ 9,164,460	$ 0.034	$ (1,567,747)
2018	Short-Term	196,440	$ 49.02	$ 9,628,929	$ 102,500			$ 962,893	$ -	$ 10,694,322	$ 0.039	$ (3,097,608)
2019	Short-Term	225,906	$ 50.24	$ 11,350,100	$ 105,063			$ 1,135,010	$ -	$ 12,590,173	$ 0.045	$ (4,993,459)
2020	Long-Term	259,792	$ 51.50	$ 13,378,931	$ 107,689	$ 1,000,000	$ 500,000	$ 1,337,893	$ 387,917	$ 16,712,430	$ 0.058	$ (9,115,717)
2021	Long-Term	298,761	$ 52.79	$ 15,770,414	$ 110,381	$ 1,025,000	$ 250,000	$ 1,577,041	$ 397,615	$ 19,130,453	$ 0.065	$ (11,533,739)
2022	Long-Term	343,575	$ 54.11	$ 18,589,376	$ 113,141	$ 1,050,625	$ 256,250	$ 1,858,938	$ 407,556	$ 22,275,885	$ 0.074	$ (14,679,172)
2023	Long-Term	395,111	$ 55.46	$ 21,912,227	$ 115,969	$ 1,076,891	$ 262,656	$ 2,191,223	$ 417,745	$ 25,976,711	$ 0.084	$ (18,379,997)
2024	Long-Term	454,378	$ 56.84	$ 25,829,038	$ 118,869	$ 1,103,813	$ 269,223	$ 2,582,904	$ 428,188	$ 30,332,034	$ 0.095	$ (22,735,320)
2025	Long-Term	522,535	$ 58.27	$ 30,445,978	$ 121,840	$ 1,131,408	$ 275,953	$ 3,044,598	$ 438,893	$ 35,458,671	$ 0.109	$ (27,861,957)
2026	Long-Term	600,915	$ 59.72	$ 35,888,197	$ 124,886	$ 1,159,693	$ 282,852	$ 3,588,820	$ 449,865	$ 41,494,313	$ 0.124	$ (33,897,600)
										$ 32,448,955		

(1) Annual Savings: targets for annual savings are shown on Schedule 1.
(2) Unit Cost: Gas Industry average of 2014-2016 in then year dollars, with 2.5% annual escalation See Appendix A.
(3) Estimated amount to provide a placeholder for an administrative resource to assist the permanent EESE Board.
(4) Estimated amount to provide a placeholder for estimated cost of permanent EESE Board.
(5) Estimated amount to provide a placeholder for estimated cost of TRM.
(6) PI and LR: Adjust PI cap to 10%, same as electric PI and retain as LR is introduced.
(7) Lost Revenue (LR): Lost revenues reflect "incremental" and "retirement" and "fuel-switching" adjustments. See Schedule 3.
(8) LDAC Rates: Calculated with actual 2014 Therm sales per 2014 Annual Report plus 2.5% growth per Year:
Year 2014 Actual (24,862,551 MMBtu x 10 = Therms)

Therms
248,625,510

2014 Therms	2015 Therms	2016 Therms	2017 Therms	2018 Therms	2019 Therms	2020 Therms	2021 Therms	2022 Therms	2023 Therms	2024 Therms	2025 Therms	2026 Therms
248,625,510	254,841,148	261,212,176	267,742,481	274,436,043	281,296,944	288,329,368	295,537,602	302,926,042	310,499,193	318,261,673	326,218,214	334,373,670

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EERS
Gas - Lost Revenue

Plan B

Schedule JJC-3

Year	Description	Annual MMBtu Savings for Lost Rev.					Cumulative	Lost Revenue Amount			
		Annual MMBtu Saving Est.	Adjustment For Increment	Adjust For Retirement	Fuel Switching	Adjusted Annual Savings	MMBtu Savings for LR	Estimated LR $/MMBtu	Amount (Not < $0)	Cap	Total LR Lower of Calc or Cap
			(1)	(2)	(3)			(4)		(5)	(Not > Cap)
2014	Actual	150,197							$ -		
2015	Approved Core	140,963							$ -		
2016	Approved Core	152,492							$ -		
2017	Short-Term	172,316	(147,884)	(16,978)	(138,486)	(131,032)	(131,032)	$ 2.691	$ -	$ 360,220	$ -
2018	Short-Term	196,440	-	(16,978)	(141,949)	37,514	(93,519)	$ 2.758	$ -	$ 369,225	$ -
2019	Short-Term	225,906	-	(16,978)	(145,497)	63,431	(30,088)	$ 2.827	$ -	$ 378,456	$ -
2020	Long-Term	259,792	-	(16,978)	(149,135)	93,679	63,592	$ 2.898	$ 184,269	$ 387,917	$ 387,917
2021	Long-Term	298,761	-	(22,906)	(152,863)	122,992	186,584	$ 2.970	$ 554,179	$ 397,615	$ 397,615
2022	Long-Term	343,575	-	(34,574)	(156,685)	152,317	338,900	$ 3.044	$ 1,031,745	$ 407,556	$ 407,556
2023	Long-Term	395,111	-	(38,165)	(160,602)	196,345	535,245	$ 3.121	$ 1,670,234	$ 417,745	$ 417,745
2024	Long-Term	454,378	-	(72,611)	(164,617)	217,150	752,395	$ 3.199	$ 2,406,547	$ 428,188	$ 428,188
2025	Long-Term	522,535	-	(37,115)	(168,732)	316,688	1,069,083	$ 3.278	$ 3,504,964	$ 438,893	$ 438,893
2026	Long-Term	600,915	-	(55,479)	(172,951)	372,485	1,441,568	$ 3.360	$ 4,844,301	$ 449,865	$ 449,865

Footnotes:

(1) Projected LR is reduced to reflect "incremental" savings levels in order to remove average 2014-2016 savings levels which were achieved without LR.

(2) Projected LR is based on reduced MMBtu savings to reflect prior installed savings that are "retired" during 2017-2026. See Schedule 6.

(3) Source: Schedule JJC-6A.

(4) Calculation of retail rate for LR is based on LR $/MMBtu using base rates from the 2014 annual reports from Energy North and Northern as follows:

	Actual Year 2014	Estimate Year 2015	Estimate Year 2016	Estimate Year 2017
2014 Act. Base Dist Rev. ($55.9m+$31.2m=$87.1m) + 2.5% escal	$ 66,900,000	$ 68,572,500	$ 70,286,813	$ 72,043,983
2014 Actual MMBtu Sales, with est. 2.5% Growth	24,862,511	25,484,074	26,121,176	26,774,205
Est. Retail Rate per MMBtu	$ 2.69	2.69	2.69	2.69

(5) Derivation of Net Lost Revenue Cap:

	Year 2017	Year 2018	Year 2019	Year 2020	Year 2021	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026
Rev	$ 72,043,983	$ 73,845,082	$ 75,691,209	$ 77,583,490	$ 79,523,077	$ 81,511,154	$ 83,548,933	$ 85,637,656	$ 87,778,597	$ 89,973,062
Cap%	$ 0.0050	$ 0.0050	$ 0.0050	$ 0.0050	$ 0.0050	$ 0.0050	$ 0.0050	$ 0.0050	$ 0.0050	$ 0.0050
Cap	$ 360,220	$ 369,225	$ 378,456	$ 387,917	$ 397,615	$ 407,556	$ 417,745	$ 428,188	$ 438,893	$ 449,865

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EERS
Gas - Details of Benefit & Costs

Plan B

Schedule JJC-4

	Benefits					Costs			
Year	Annual Pure MMBtu Savings	Annual Equivalent MMBtu Savings (1)	Lifetime Equiv. MMBtu Savings (2)	Benefits Per MMBtu	NPV Benefits 1.36% Disc. Rate (3)	Utility Cost (Incl. PI & LR)	Util+Cust "Installed" Cost (4)	NPV Costs 2.5% Disc. Rate	B/C
2017	172,316	172,827	2,480,309	$ 20,024,715	$ 20,024,715	$ 9,164,460	$ 13,680,492	$ 13,680,492	1.46
2018	196,440	197,022	2,827,553	$ 23,138,638	$ 22,828,175	$ 10,694,322	$ 15,964,234	$ 15,574,862	1.47
2019	225,906	226,576	3,251,686	$ 26,971,322	$ 26,252,401	$ 12,590,173	$ 18,794,315	$ 17,888,700	1.47
2020	259,792	260,562	3,739,438	$ 31,438,852	$ 30,190,261	$ 16,712,430	$ 24,947,925	$ 19,264,173	1.57
2021	298,761	299,646	4,300,354	$ 36,646,384	$ 34,718,801	$ 19,130,453	$ 28,557,492	$ 21,264,043	1.63
2022	343,575	344,593	4,945,407	$ 42,716,491	$ 44,483,133	$ 22,275,885	$ 33,252,920	$ 24,058,312	1.85
2023	395,111	396,282	5,687,218	$ 49,792,050	$ 45,915,614	$ 25,976,711	$ 38,777,426	$ 27,900,266	1.65
2024	454,378	455,724	6,540,301	$ 58,039,605	$ 52,797,747	$ 30,332,034	$ 45,278,950	$ 33,164,649	1.59
2025	522,535	524,083	7,521,346	$ 67,653,285	$ 60,723,399	$ 35,458,671	$ 52,931,873	$ 40,407,905	1.50
2026	600,915	602,695	8,649,548	$ 78,859,376	$ 69,831,909	$ 41,494,313	$ 61,941,740	$ 50,463,936	1.38

footnotes:

(1) Factor for equivalent MMBtu saved, based on 3-year average (2014-2016)	1.00	See Sch. 7
(2) Est. average lifetime for equivalent savings, based on 3-year average (2014-2016)	14.4	See Sch. 7
(3) Est. value of benefits/lifetime MMBtu, based on 3-year average (2014-2016)	$ 8.073	See Sch. 7
(4) Estimated installed cost based on 3-year average (2014-2016).	1.49	See Sch 7

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EERS

Plan B

Schedule JJC-5

Gas - Derivation of Utility Unit Cost per Annual MMBtu Saved:

	Unit Cost to Achieve Ann. MMBtu Savings		LDAC Rate Calculation	
Forecast for 2016-2026:				
2016 Escalation at 2.5%	$ 46.66	(1)	$ 0.026	(2)
2017 Escalation at 2.5%	$ 47.82		$ 0.026	
2018 Escalation at 2.5%	$ 49.02		$ 0.026	
2019 Escalation at 2.5%	$ 50.24		$ 0.026	
2020 Escalation at 2.5%	$ 51.50		$ 0.026	
2021 Escalation at 2.5%	$ 52.79		$ 0.026	
2022 Escalation at 2.5%	$ 54.11		$ 0.026	
2023 Escalation at 2.5%	$ 55.46		$ 0.026	
2024 Escalation at 2.5%	$ 56.84		$ 0.026	
2025 Escalation at 2.5%	$ 58.27		$ 0.026	
2026 Escalation at 2.5%	$ 59.72		$ 0.026	

Footnotes:

(1) Calculation of Cost to achieve Annual Savings - Average cost per MMBtu to achieve Savings:

	2014 Actual	2015 Core	2016 Core	Average
Utility Cost (Excl PI)	$ 6,480,979	$ 6,728,741	$ 6,969,462	$ 6,726,394
Annual MMBtu Savings	150,197	140,963	152,492	147,884
Unit Cost per Annual MMBtu	$ 43.15	$ 47.73	$ 45.70	$ 45.48
2015 - Escal at 1.025	$ 44.23			
2016 - Escal at 1.025	$ 45.33	$ 48.93	$ 45.70	$ 46.66

		Final PI Filing
Spending	Northern	$ 1,167,000.0
	Energy North	$ 5,313,979.0
		$ 6,480,979.0

(2) Calculation of LDAC Rate per Therm (assumes Cost and therm sales increase at 2.5% per year):

	2014 Actual	2015 Estimate	2016 Estimate
Utility Cost	$ 6,480,979	$ 6,728,741	$ 6,896,960
Annual Therm Sales	248,625,110	254,840,738	261,211,756
LDAC Rate Per Therm	$ 0.026	$ 0.026	$ 0.026
Percent EE Spending to Sales Rev Dollars			
EE Spending	$ 6,480,979	$ 6,728,741	$ 6,969,462
Distribution Sales Revenue Dollars	$ 218,048,410	$ 223,499,620	$ 229,087,111
Percent Utility Cost to Sales Rev. Dollars	3%	3%	3%
Percent MMBtu Savings to MMBtu Usage:			
MMBtu Savings	150,197	140,963	152,492
MMBtu Usage	24,862,511	25,484,074	26,121,176
% Savings	0.6%	0.6%	0.6%

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EERS

Gas - Derivation of Estimated Retirement of Prior EE Installations

Plan B

Schedule JJC-6

Lifetime Sav			Reported Core Savings / Retirements			Retirement MMBtu Discounted by 50 Percent
			Lifetime MMBtu Savings	Est. Life (Years)	Est. Annual Savings	
			(1)	(2)		(2)
Year Installed	Year Retired					
2001 (1)	2017	Liberty	349,226			
		Unitil	138,092			
		Total	487,318	14.4	33,956	16,978
2002 (1)	2018	Liberty	349,226			
		Unitil	138,092			
		Total	487,318	14.4	33,956	16,978
2003 (1)	2019	Liberty	349,226	14.4	24,334	
		Unitil	138,092	14.4	9,622	
		Total	487,318		33,956	16,978
2004	2020	Liberty	349,226	14.4	24,334	
		Unitil	138,092	14.4	9,622	
		Total	487,318		33,956	16,978
2005	2021	Liberty	507,395	14.4	35,355	
		Unitil	150,066	14.4	10,457	
		Total	657,461		45,812	22,906
2006	2022	Liberty	678,085	14.4	47,249	
		Unitil	314,287	14.4	21,899	
		Total	992,372		69,148	34,574
2007	2023	Liberty	840,437	14.4	58,561	
		Unitil	254,997	14.4	17,768	
		Total	1,095,434		76,329	38,165
2008	2024	Liberty	1,862,102	14.4	129,750	
		Unitil	222,052	14.4	15,472	
		Total	2,084,154		145,223	72,611
2009	2025	Liberty	858,374	14.4	59,811	
		Unitil	206,927	14.4	14,419	
		Total	1,065,301		74,230	37,115
2010	2026	Liberty	1,226,114	14.4	85,435	
		Unitil	366,302	14.4	25,524	
		Total	1,592,416		110,959	55,479

footnotes:

(1) Reflects 2004 data as a proxy.

(2) Based on 3-year average 2014-2016 14.4

(3) It is difficult to project future customer purchase of standard vs. high efficiency equipment, therefore a discount of 50 percent is applied.

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EERS-Gas-Lost Revenues

Fuel Switching - Estimate for 2017

Schedule JJC 6A

Description:		Liberty-Gas - 2017 Residential	Liberty-Gas - 2017 C&I	Liberty-Gas - 2017 Total	Unitil-Gas - 2017 Residential	Unitil-Gas - 2017 C&I	Unitil-Gas - 2017 Total	Annual Therms Fuel Switch'g
New Customers:								
No. of new customers January 2014-September 2015		311	70		980	406		
Less: new Res. Cust. (above) constructing new homes (?)		-	-		-	-		
Sub-Total		311	70		980	406		
Annual Equivalent Conversion % (12/10 for Liberty; 12/21 for Unitil)		120%	120%		57%	57%		
Estimated Annual Equivalent No. of new customers		373	84		559	231		
Estimated % conversions from oil or other fossil fuel heat		100%	100%		51%	51%		
No. new customers - oil/other fossil to natural gas		311	84		285	118		
Existing Customers:								
Existing customers switching to natural gas		-			54	24		
Annual Equivalent Conversion % (12/21)		-	-		57%	57%		
Estimated Annual Equivalent No. of existing customers		incl. above	incl. above		31	14		
Total New and Existing		311	84		316	132		
Average annual therm usage (2)		776	4,176		769	4,176		
Extended Therms	(1)	241,336	350,784		242,747	549,997		
Conversion to MMBtu (Therms divided by 10)	(2)	24,134	35,078	59,212	24,275	55,000	79,274	138,486

footnotes:

(1) Liberty-Gas EE participants that switched from oil/other fossil to gas; Unitil-Gas does not track fuel conversions; but indicates majority of new customers converted.

(2) Used Liberty-Gas estimate of average annual non-residential for consistency for Unitil-Gas.

(3) Source: Data Responses in Core 2016 Update Docket DE 14-216: Staff 3-7 and Staff 3-8 (Unitil-Gas); and, Staff 3-9 and Staff 3-10 (Liberty-Gas).

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EERS

Gas - Average 2014-2016 Data

Plan B

Schedule JJC-7

Description	2014 Actual (final)		2015 Core		2016 Core Update		Average 2014-2016	
Ratio of Equiv to Pure kWh (Liberty/Unitil Gas):								
Gas-annual MMBtu Savings		150,197		140,963		152,492		147,884
kWh Savings	101,614		283,486		46		128,382	
Conversion Factor - kWh to MMBtu	293	347	293	968	293	0	293	438.16
MMBtu Savings		150,544		141,931		152,492		148,322
Factor for Equiv. kWh		1.002		1.007		1.000		1.003
Measure Life:								
Lifetime MMBtu Savings		1,757,567		2,236,530		2,372,948		2,122,348
Annual MMBtu Savings		150,197		140,963		152,492		147,884
Est. Measure Life		11.7		15.9		15.6		14.4
Benefits per lifetime MMBtu saved:								
Benefit Dollars		$ 17,698,178		$ 16,065,000		$ 17,641,000		17,134,726
Lifetime MMBtu Savings		1,757,567		2,236,530		2,372,948		2,122,348
Rate per Equiv. kWh		10.07		7.18		7.43		$ 8.07
Customer Cost Factor								
"Customer Cost"		$ 2,646,515		$ 3,695,000		$ 4,348,000		3,563,172
"Utility" Cost Incl. PI and LR at est. 7.5%	$ 6,480,789	$ 6,966,848	$ 6,728,741	$ 7,233,397	$ 6,969,462	$ 7,492,172	$ 6,726,331	7,230,805
"Installed" Cost		$ 9,613,363		$ 10,928,397		$ 11,840,172		10,793,977
Installed Cost Factor / Utility Cost		1.38		1.51		1.58		1.49

EERS

EERS Savings Targets

Gas Industries

Plan B

Schedule JJC-8

EERS Targets

MMBtu Savings as % of Load (1)

Industry	Year	ME	VT	RI	CT (2)	MA	NH
Gas	2014	0.30%		1.00%	0.30%	1.10%	0.60%
	2015	0.30%			0.30%	1.15%	0.57%
	2016	0.30%					0.61%
	2017						0.69%
	2018						0.79%
	2019						0.91%

Footnotes:

(1) Source: ACEEE, Energy Efficiency Resource Standards, April, 2014 for all states.

(2) CT Draft Decision, August 23, 2013, page 20 (gas).

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EERS

Gas - Summary of PI and Lost Revenue Impacts for certain years

Plan B

Schedule JJC-9

		Spending	PI	% of Spending	% of Sales Rev
Year 2014 Actual:					
PI	Liberty Gas				$ 66,900,000
	Unitil Gas				
	Total	$ 6,966,848	$ 575,924	8.3%	0.9%
Year 2017 Est:					
PI			$ 824,042	10.0%	$ 72,043,983
Lost Rev			$ -		
Total		$ 8,240,419	$ 824,042	10.0%	1.1%
Year 2018 Est:					
PI			$ 962,893		$ 73,845,082
Lost Rev			$ -		
Total		$ 9,628,929	$ 962,893	10.0%	1.3%
Year 2019 Est:					
PI			$ 1,135,010		$ 75,691,209
Lost Rev			$ -		
Total		$ 11,350,100	$ 1,135,010	10.0%	1.5%
Year 2020					
PI			$ 1,337,893		$ 77,583,490
Lost Rev			$ 387,917		
Total		$ 13,378,931	$ 1,725,811	12.9%	2.2%
Year 2021					
PI			$ 1,577,041		$ 79,523,077
Lost Rev			$ 397,615		
Total		$ 15,770,414	$ 1,974,657	12.5%	2.5%
Year 2022					
PI			$ 1,858,938		$ 81,511,154
Lost Rev			$ 407,556		
Total		$ 18,589,376	$ 2,266,493	12.2%	2.8%
Year 2023					
PI			$ 2,191,223		$ 83,548,933
Lost Rev.			$ 417,745		
Total		$ 21,912,227	$ 2,608,967	11.9%	3.1%
Year 2024					
PI			$ 2,582,904		$ 85,637,656
Lost Rev			$ 428,188		
Total		$ 25,829,038	$ 3,011,092	11.7%	3.5%
Year 2025					
PI			$ 3,044,598		$ 87,778,597
Lost Rev			$ 438,893		
Total		$ 30,445,978	$ 3,483,491	11.4%	4.0%
Year 2026					
PI			$ 3,588,820		$ 89,973,062
Lost Rev			$ 449,865		
Total		$ 35,888,197	$ 4,038,685	11.3%	4.5%

PI (2020-2026)	$ 16,181,416
LR (2020-2026)	$ 2,927,780
Total	$ 161,814,161
Percent	11.8%

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EERS

Attachment 2A

Overview of Staff Model – Savings, Cost, SBC/LDAC

DE 15-137
EERS - Electric Utilities

PLAN A

Year	Pure kWh Savings (1) (a)	Percent to 2014 Usage (1)(3)	Spending to Achieve Savings: Utility (2) (b)	Less: ISO/RGGI (2) (c)	Plus EESE (2) (d)	SBC Total (e=b+c+d)	SBC kWh (4) (f)	SBC Rate (g=e/f)
2014	67,728,171	0.6%						$ 0.0018
2015	56,979,474	0.5%						$ 0.0018
2016	53,087,627	0.5%						$ 0.0018
2017	58,396,390	0.5%	$ 27,402,937	$ 5,000,000	$ 100,000	$ 22,502,937	10,988,357,778	$ 0.0020
2018	64,819,993	0.6%	$ 31,177,691	$ 5,000,000	$ 102,500	$ 26,280,191	10,988,357,778	$ 0.0024
2019	72,598,392	0.7%	$ 36,712,454	$ 5,000,000	$ 105,063	$ 31,817,517	10,988,357,778	$ 0.0029
2020	82,036,183	0.8%	$ 44,615,454	$ 5,000,000	$ 1,607,689	$ 41,223,143	10,988,357,778	$ 0.0038
2021	92,700,886	0.9%	$ 51,978,761	$ 5,000,000	$ 1,385,381	$ 48,364,142	10,988,357,778	$ 0.0044
2022	104,752,002	1.0%	$ 59,676,428	$ 5,000,000	$ 1,420,016	$ 56,096,444	10,988,357,778	$ 0.0051
2023	118,369,762	1.1%	$ 68,579,052	$ 5,000,000	$ 1,455,516	$ 65,034,568	10,988,357,778	$ 0.0059
2024	133,757,831	1.2%	$ 78,876,986	$ 5,000,000	$ 1,491,904	$ 75,368,890	10,988,357,778	$ 0.0069
2025	151,146,349	1.4%	$ 90,790,702	$ 5,000,000	$ 1,529,201	$ 87,319,903	10,988,357,778	$ 0.0079
2026	170,795,374	1.6%	$ 104,575,548	$ 5,000,000	$ 1,567,431	$ 101,142,979	10,988,357,778	$ 0.0092
10-Yr. Total	1,049,373,162	9.74%	$ 594,386,013	$ 50,000,000	$ 10,764,701	$ 555,150,714		

footnotes:
(1) Att. 2A, Schedule JJC-1
(2) Att. 2A, Schedule JJC-2
(3) 2014 actual kWh usage 10,770,750,548
(4) From 2016 Core Update, p. 2. 10,988,357,778

DE 15-137

EERS - Electric Utilities

PLAN B								
			Spending to Achieve Savings				SBC	
Year	Pure kWh Savings (1)	Percent to 2014 Usage (1)(3)	Utility (2)	Less: ISO/RGGI (2)	Plus EESE (2)	Total	kWh (4)	SBC Rate
	(a)		(b)	(c)	(d)	(e=b+c+d)	(f)	(g=e/f)
2014	67,728,171	0.6%						$ 0.0018
2015	56,979,474	0.5%						$ 0.0018
2016	53,087,627	0.5%						$ 0.0018
2017	61,050,771	0.6%	$ 28,648,525	$ 5,000,000	$ 100,000	$ 23,748,525	10,988,357,778	$ 0.0020
2018	72,039,910	0.7%	$ 34,650,391	$ 5,000,000	$ 102,500	$ 29,752,891	10,988,357,778	$ 0.0027
2019	86,447,892	0.8%	$ 44,608,598	$ 5,000,000	$ 105,063	$ 39,713,661	10,988,357,778	$ 0.0036
2020	103,737,470	1.0%	$ 57,678,332	$ 5,000,000	$ 1,607,689	$ 54,286,021	10,988,357,778	$ 0.0049
2021	124,484,964	1.2%	$ 72,404,301	$ 5,000,000	$ 1,385,381	$ 68,789,682	10,988,357,778	$ 0.0063
2022	149,381,957	1.4%	$ 87,432,760	$ 5,000,000	$ 1,420,016	$ 83,852,776	10,988,357,778	$ 0.0076
2023	179,258,348	1.7%	$ 105,877,153	$ 5,000,000	$ 1,455,516	$ 102,332,669	10,988,357,778	$ 0.0093
2024	215,110,018	2.0%	$ 128,522,128	$ 5,000,000	$ 1,491,904	$ 125,014,032	10,988,357,778	$ 0.0114
2025	258,132,022	2.4%	$ 156,332,778	$ 5,000,000	$ 1,529,201	$ 152,861,979	10,988,357,778	$ 0.0139
2026	309,758,426	2.9%	$ 190,496,140	$ 5,000,000	$ 1,567,431	$ 187,063,571	10,988,357,778	$ 0.0170
10-Yr. Total	1,559,401,778	14.48%	$ 906,651,106	$ 50,000,000	$ 10,764,701	$ 867,415,807		

footnotes:

(1) Att. 2A, Schedule JJC-1

(2) Att. 2A, Schedule JJC-2

(3) 2014 actual kWh usage 10,770,750,548

(4) From 2016 Core Update, p. 2. 10,988,357,778

DE 15-137

EERS - Gas Utilities

PLAN A								
			Spending to Achieve Savings				LDAC	
Year	MMBtu Savings (1)	Percent to 2014 Usage (1)(3)	Utility (2)	Less: ISO/RGGI (2)	Plus EESE (2)	Total	Therms (4)	Rate Per Therm
	(a)		(b)	(c)	(d)	(e=b+c+d)	(f)	(g=e/f)
2014	150,197	0.6%						
2015	140,963	0.6%						
2016	152,492	0.6%						$ 0.0291
2017	163,166	0.7%	$ 8,583,162	$ -	$ 100,000	$ 8,683,162	267,742,481	$ 0.0324
2018	176,220	0.7%	$ 9,501,560	$ -	$ 102,500	$ 9,604,060	274,436,043	$ 0.0350
2019	192,080	0.8%	$ 10,615,617	$ -	$ 105,063	$ 10,720,680	281,296,944	$ 0.0381
2020	211,287	0.8%	$ 11,969,109	$ -	$ 1,607,689	$ 13,576,798	288,329,368	$ 0.0471
2021	232,416	0.9%	$ 13,528,186	$ -	$ 1,385,381	$ 14,913,567	295,537,602	$ 0.0505
2022	255,658	1.0%	$ 15,481,112	$ -	$ 1,420,016	$ 16,901,128	302,926,042	$ 0.0558
2023	281,224	1.1%	$ 17,427,760	$ -	$ 1,455,516	$ 18,883,276	310,499,193	$ 0.0608
2024	309,346	1.2%	$ 19,621,926	$ -	$ 1,491,904	$ 21,113,830	318,261,673	$ 0.0663
2025	340,281	1.4%	$ 22,095,151	$ -	$ 1,529,201	$ 23,624,352	326,218,215	$ 0.0724
2026	374,309	1.5%	$ 24,882,998	$ -	$ 1,567,431	$ 26,450,429	334,373,670	$ 0.0791
10-Yr. Tota	2,535,987	10.20%	$ 153,706,581	$ -	$ 10,764,701	$ 164,471,282		

footnotes:

(1) Att. 2A, Schedule JJC-1

(2) Att. 2A, Schedule JJC-2

(3) 2014 actual MMBtu usage 24,862,611

(4) Att. 2A, Schedule JJC-2, footnote 8.

DE 15-137
EERS - Gas Utilities

PLAN B								
			Spending to Achieve Savings				LDAC	
Year	MMBtu Savings (1)	Percent to 2014 Usage (1)(3)	Utility (3)	Less: ISO/RGGI (3)	Plus EESE (3)	Total	Therm (4)	Rate per Therm
	(a)		(b)	(c)	(d)	(e=b+c+d)	(f)	(g=e/f)
2014	150,197	0.6%						
2015	140,963	0.6%						
2016	152,492	0.6%						$ 0.0291
2017	172,316	0.7%	$ 9,064,460	$ -	$ 100,000	$ 9,164,460	267,742,481	$ 0.0342
2018	196,440	0.8%	$ 10,591,822	$ -	$ 102,500	$ 10,694,322	274,436,043	$ 0.0390
2019	225,906	0.9%	$ 12,485,110	$ -	$ 105,063	$ 12,590,173	281,296,944	$ 0.0448
2020	259,792	1.0%	$ 15,104,741	$ -	$ 1,607,689	$ 16,712,430	288,329,368	$ 0.0580
2021	298,761	1.2%	$ 17,745,072	$ -	$ 1,385,381	$ 19,130,453	295,537,602	$ 0.0647
2022	343,575	1.4%	$ 20,855,869	$ -	$ 1,420,016	$ 22,275,885	302,926,042	$ 0.0735
2023	395,111	1.6%	$ 24,521,195	$ -	$ 1,455,516	$ 25,976,711	310,499,193	$ 0.0837
2024	454,378	1.8%	$ 28,840,130	$ -	$ 1,491,904	$ 30,332,034	318,261,673	$ 0.0953
2025	522,535	2.1%	$ 33,956,470	$ -	$ 1,529,201	$ 35,485,671	326,218,215	$ 0.1088
2026	600,915	2.4%	$ 39,925,882	$ -	$ 1,567,431	$ 41,493,313	334,373,670	$ 0.1241
10-Yr. Total	3,469,729	13.96%	$ 213,090,751	$ -	$ 10,764,701	$ 223,855,452		

footnotes:
(1) Att. 2A, Schedule JJC-1
(2) Att. 2A, Schedule JJC-2
(3) 2014 actual MMBtu usage 24,862,611
(4) Att. 2A, Schedule, JJC-2, footnote 8

Attachment 3

Annual State EERS Targets for reduction in kWh sales each year

Source: American Council for an Energy-Efficient Economy 2011

State	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Cumulative 2020	Type
Arizona	N/A	N/A	1.25%	3.00%	5.00%	7.25%	9.50%	12.00%	14.50%	17.00%	19.50%	22.00%	22.00%	Mandatory Standard
Arkansas	N/A	N/A	0.25%	0.75%	1.50%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.50%	Mandatory Standard
California	1.31%	2.56%	3.83%	5.11%	6.17%	7.13%	8.05%	9.00%	9.97%	10.96%	11.95%	12.94%	12.94%	Mandatory Standard
Colorado	0.53%	1.29%	2.09%	3.23%	4.44%	5.72%	7.07%	8.49%	10.00%	11.59%	13.25%	14.93%	14.93%	Mandatory Standard
Delaware	0.50%	1.25%	2.50%	5.00%	8.00%	11.00%	15.00%	N/A	N/A	N/A	N/A	N/A	15.00%	Pending
Hawaii	1.50%	3.00%	4.50%	6.00%	7.50%	9.00%	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	18.00%	Mandatory Standard
Illinois	0.40%	1.00%	1.80%	2.80%	4.20%	6.00%	8.00%	10.00%	12.00%	14.00%	16.00%	18.00%	18.00%	Cost Cap
Indiana	N/A	0.30%	0.80%	1.49%	2.39%	3.46%	4.77%	6.26%	7.95%	9.84%	11.83%	13.81%	13.81%	Mandatory Standard
Iowa	1.00%	2.20%	3.50%	4.90%	6.30%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	6.30%	Mandatory Standard
Maine	N/A	N/A	1.00%	2.20%	3.60%	5.00%	N/A	N/A	N/A	N/A	N/A	N/A	5.00%	Mandatory Standard
Maryland	0.99%	2.23%	4.70%	7.70%	10.70%	13.70%	16.70%	N/A	N/A	N/A	N/A	N/A	16.70%	Mandatory Standard
Massachusetts	1.00%	2.50%	4.50%	6.90%	9.30%	11.70%	14.10%	16.50%	18.90%	21.30%	23.70%	26.10%	26.10%	Mandatory Standard
Michigan	0.30%	0.80%	1.55%	2.55%	3.55%	4.55%	5.55%	6.55%	7.55%	8.55%	9.55%	10.55%	10.55%	Cost Cap
Minnesota	N/A	1.50%	3.00%	4.50%	6.00%	7.50%	9.00%	10.50%	12.00%	13.50%	15.00%	16.50%	16.50%	Mandatory Standard
Nevada	0.77%	0.80%	1.58%	1.62%	2.41%	2.46%	3.00%	3.05%	3.11%	3.16%	3.21%	3.76%	3.76%	Combined RES-EERS
New Mexico	N/A	0.86%	1.72%	2.56%	3.38%	4.20%	4.80%	5.40%	5.98%	6.56%	7.32%	8.06%	8.06%	Exit Ramp
New York	2.10%	4.22%	6.38%	8.56%	10.76%	12.99%	15.25%	N/A	N/A	N/A	N/A	N/A	15.25%	Mandatory Standard

Attachment 4:
MI Western Energy Efficiency Targets and Funding Levels

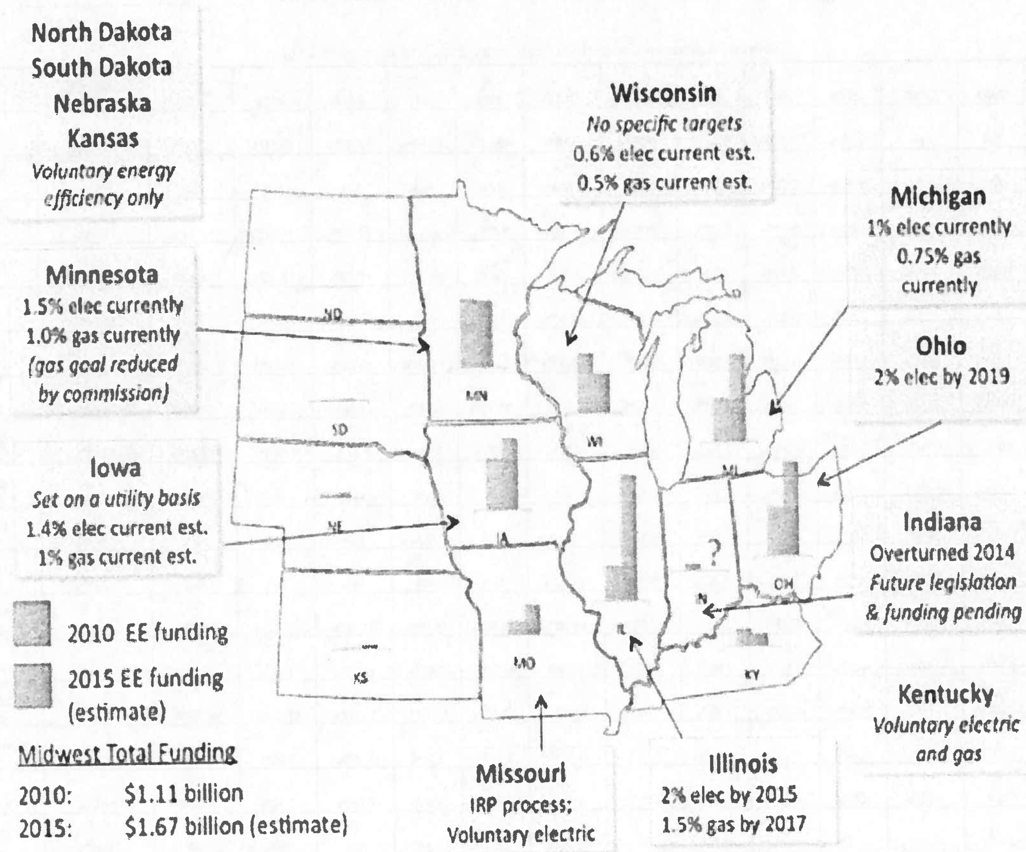

Figure 1: Midwest Efficiency Targets and Funding Levels
Midwest Energy Efficiency Alliance, April 2014

Attachment 5

State	Citation	Utility Incentives
Indiana	170 IAC 4-8-7	When appropriate, the Commission may provide the utility with a shareholder incentive to encourage participation in and promotion of a demand-side management (DSM) program. A utility may propose a shareholder incentive based on particular attributes of a DSM program and the program's desired results. A shareholder incentive may include, but is not limited to, the following: (a) a percentage share of the net benefit attributable to a (DSM) program; (b) authorization for the utility to a greater-than-normal return on equity for a rate-based (DSM) expenditure; and/or (c) an adjustment to a utility's overall return on equity in response to quantitative or qualitative evaluation of demand-side management program performance.
Kansas	Final Order in 08-GMX-441-GIV	The Commission's policy shall be to consider proposals for shared savings performance incentive plans where they are tied to specific energy efficiency programs the Commission considers most desirable. Approved Westar's Shared Savings mechanism in docket 10-WSEE-775-TAR.
Kentucky	278.285	Allows utilities to include in customer bill surcharge an incentive bonus associated with approved cost-effective energy efficiency programs.
Michigan	PA 295 Section 75	An energy optimization plan of a provider whose rates are regulated by the Commission may authorize a commensurate financial incentive for the provider for exceeding the energy optimization performance standard. The total amount of a financial incentive shall not exceed the lesser of the following amounts: (a) 25% of the net cost reductions experienced by the provider's customers as a result of implementation of the energy optimization plan. (b) 15% of the provider's actual energy efficiency program expenditures for the year.
Minnesota	Minn. Stat. 216B.16 Subd. 6c	The Commission may order public utilities to develop and submit for Commission approval incentive plans that describe the method of recovery and accounting for utility conservation expenditures and savings. In developing the incentive plans, the Commission shall ensure the effective involvement of interested parties. In approving incentive plans, the Commission shall consider: (1) whether the plan is likely to increase utility investment in cost-effective energy conservation; (2) whether the plan is compatible with the interest of utility ratepayers and other interested parties; (3) whether the plan links the incentive to the utility's performance in achieving cost-effective conservation; and (4) whether the plan is in conflict with other provisions of this chapter. The Commission may set rates to encourage the vigorous and effective implementation of utility conservation programs. The Commission may: (1) increase or decrease any otherwise allowed rate of return on net investment based upon the utility's skill, efforts, and success in conserving energy; (2) share between ratepayers and utilities the net savings resulting from energy conservation programs to the extent justified by the utility's skill, efforts, and success in conserving energy; and (3) adopt any mechanism that satisfies the criteria of this subdivision, such that implementation of cost-effective conservation is a preferred resource choice for the public utility considering the impact of conservation on earnings of the public utility.
Missouri	393.1075 RSMo. Cum. Supp. 2010	Ensures that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances these incentives.
Nebraska		All electric utilities in Nebraska are either public power districts or cooperatives. As such, they do not have stockholders, and there is no need for an incentive mechanism. As an example, Omaha Public Power District identified this in its 2009 report under the Public Utility Regulatory Policies Act (PURPA)[154].
Ohio	OAC 4901:1-39-07	Utilities can recover "shared savings."
South Dakota	SDCL 49-34A-8.2.	Provides incentive rates for improved performance and efficiency. In addition to any other rate authorized, the Commission may approve incentive rates to encourage improved performance and efficiency of public utilities. The rates are in the form of preapproved rate models made applicable as levels of performance are attained by the utility.
Wisconsin	Docket 6680-UR-114	Utilities can propose incentives as part of their rate cases for the voluntary utility-administered energy efficiency programs that are outside of the Focus on Energy program. The incentive is in the form of shared savings. Alliant (WP&L) has received Commission approval to utilize the shared savings mechanism for one of the programs it offers outside of the Focus on Energy program.

* Illinois, Iowa, and North Dakota do not have utility incentive mechanisms.

Attachment 6.
Summary of selected Energy Efficiency Secondary Market Transactions

	Craft 3 Self-Help	Keystone HELP	NYSERDA	Toledo PACE	Connecticut C-PACE	Delaware SEU	HERO PACE I	HERO PACE II	WHEEL (forthcoming)	Kilowatt (forthcoming)
Date	December 2013	January 2013	NYSERDA	Toledo PACE	Connecticut C-PACE	Delaware SEU	February 2014	October 2014	TBD	TBD
Size	$15.7M	$24M	August 2013	2012-2013	May 2014	July 2013	$104M	$129M	TBD	TBD
Transaction Type	Portfolio Sale	Portfolio Sale	Revenue Bond (as QECB)	Revenue Bond	Revenue Bond	Revenue Bond	ABS	ABS	ABS	ABS
Seller (Type)	Craft3 (Private)	PA Treasury (Public)	NYSERDA (Public)	Toledo Lucas-County Port Authority (Public)	Public Finance Authority - conduit (Public)	Delaware SEU (Quasi-public)	WRCOG (Quasi-public)	WRCOG and SANBAG (Quasi-public)	WHEEL SPV (Private)	Kilowatt (Private)
Primary Capital Source	Craft 3 funds	Treasury funds	RGGI funds	Municipal revenue bonds	Municipal revenue bonds	ESCO contracts	Limited Obligation Improvement Bonds	Limited Obligation Improvement Bonds	Citibank/ Pennsylvania Treasury line of credit	Citibank line of credit
Market Sector of Underlying Loans	Residential	Residential	Residential	Commercial	Commercial	Public/ Institutional	Residential	Residential	Residential	Residential
Investor Type	Single purchaser	Consortium	Public Offer	Private Placement	Private Placement	Public Offer	Private Placement	Private Placement	Public Offer	TBD
Investor(s) if Known	Self-Help	Fox Chase, WSFS Bank, National Penn	Many, including Impact Investors	Not reported	Clean Fund, CGB	Many	Not reported	Not reported	TBD	TBD
Rating	n/a	n/a	AAA/Aaa	Unrated	Unrated	AA+	AA	AA	TBD	TBD
Yield*	5.99%	6%	3.2%	Not reported	Not reported	3.7%	4.75%	3.99%	TBD	TBD
Average Maturity	20 years	4 years	7 years	Not reported	Not reported	Not reported	11 years	11 years	TBD	TBD
Credit Enhancement (see Chapter 4 for definitions)	Reserve Account, Partial Guarantee	Sub ordination	Loan Guarantee	Reserve Account	Sale at discount	Appropriations backing (guarantee)	Over collateralization (3%), Liquidity Reserve (3% growing to 7%), Excess Spread (4%)	Over collateralization, Liquidity Reserve (3% growing to 7%), Excess Spread (4%)	Sub ordination (~20%)	TBD

* Yield to investors. Note that effective cost of capital to issuers may be lower than yield in the case of QECBs, which receive an interest rate subsidy.

Attachment 7

Detailed taxonomy of energy efficiency programs as prepared by LBNL.

Residential Programs

Detailed category	Detailed program definition	Simplified category	Present or Absent in NH Core
Behavioral/On line Audit/Feedback	Residential programs designed around directly influencing household habits and decision-making on energy consumption through quantitative or graphical feedback on consumption, sometimes accompanied by tips on savings energy. These programs include behavioral feedback programs (in which energy usage reports compare a consumer's household energy usage with those of similar consumers); online audits that are completed by the consumer; and in-home displays that help consumers assess their usage in near real time. This program category does not include on-site energy assessments or audits.	Behavior/ Education	Yes
Consumer Product Rebate/ Appliances	Programs that incentivize the sale, purchase and installation of appliances (e.g., refrigerators, dishwashers, clothes washers and dryers) that are more efficient than current standards. Appliance recycling and the sale/purchase/installation of HVAC equipment, water heaters and consumer electronics are accounted for separately.	Consumer Product rebate	Yes
Consumer Product Rebate/ Electronics	Programs that encourage the availability and purchase/lease of more efficient personal and household electronic devices, including but not limited to televisions, set-top boxes, game consoles, advanced power strips, cordless telephones, PCs and peripherals specifically for home use, chargers for phones/smart phones/tablets. A comprehensive efficiency program to decrease the electricity use of consumer electronics products includes two focuses: product purchase and product use. Yet not every consumer electronics program will seek to be comprehensive. Some programs will embark on ambitious promotions of multiple electronics products, employing upstream, midstream, and downstream strategies with an aggressive marketing and education component. At the other end of the continuum, a program administrator may choose to focus exclusively	Consumer Product rebate	No incentives or markdowns for these products

	on consumer education.		
Consumer Product Rebate/Lighting	Programs aimed specifically at encouraging the sale/purchase and installation of more efficient lighting in the home. These programs range widely from point-of-sale rebates to CFL mailings or giveaways. Measures tend to be CFLs, fluorescent fixtures, LED lamps, LED fixtures, LED holiday lights and lighting controls, including occupancy monitors/switches.	Consumer Product Rebate	Yes
Appliance Recycling	Programs designed to remove less efficient appliances (typically refrigerators and freezers) from households.	Consumer Product Rebate	Yes
Multi-Family	Multi-family programs are designed to encourage the installation of energy efficient measures in common areas, units or both for residential structures of more than four units. These programs may be aimed at building owners/managers, tenants or both.	**Multi-Family**	Yes
New Construction	Programs that provide incentives and possibly technical services to ensure new homes are built or manufactured to energy performance standards higher than applicable code (e.g., ENERGY STAR Homes). These programs include new multi-family and new/replacement mobile homes.	**New Construction**	Yes
HVAC	Programs designed to encourage the distribution, sale/purchase, proper sizing and installation of HVAC systems that are more efficient than current standards. Programs tend to support activities that focus on central air conditioners, air source heat pumps, ground source heat pumps, and ductless systems that are more efficient than current energy performance standards, as well as climate controls and the promotion of quality installation and quality maintenance.	Prescriptive	Yes
Insulation	Programs designed to encourage the sale/purchase and installation of insulation in residential structures, often through per-square-foot incentives for insulation of specific R-values versus an existing baseline. Programs may be point-of-sale rebates or rebates to insulation installation contractors.	Prescriptive	No: No separate prescriptive incentives (incentives in HEA+HPwES when installed by BPI certified contractor)
Pool Pump	Programs that incentivize the installation of higher efficiency or variable speed pumps and controls, such as timers, for swimming pools.	Prescriptive	No

Prescriptive	Residential programs that provide or incentivize a set of pre-approved measures not included in, or distinguishable from, the other residential program categories (e.g., direct install, HVAC, lighting). For example, if a residential program features rebates for a large set of mixed, pre-approved offerings (e.g., insulation, HVAC, appliances, lighting), yet the relative contribution of each measure to program savings is unclear or no single measure accounts for a large majority of the savings, then the program should be classified as a residential prescriptive program.		No…all prescriptive (or custom) via BPI auditor recommendation in HEA and HPwES
Water Heater	Programs designed to encourage the distribution, sale/purchase and installation of electric and/or gas water-heating systems that are more efficient than current standards, including high efficiency water storage tank and tankless systems.		Yes
Windows	Programs designed to encourage the sale/purchase and installation of efficient windows in residential structures.		No specific windows program: However efficient windows are an element of ES Home program. There are no stand-alone rebates for windows. They are sometimes installed, when cost effectiveness, in HPWES/HEA.
Whole Home/ Direct Install	Direct-install programs provide a set of pre-approved measures that may be installed at the time of a visit to the customer premises or provided as a kit to the consumer, usually at modest or no cost to the consumer and sometimes accompanied by a rebate. Typical measures include CFLs, lowflow showerheads, faucet aerators, water-heater wrap and weather stripping. Such programs may also include a basic, walk-through energy assessment or audit, but the savings are principally derived from the installation of the provided measures. Education programs that supply kits by sending them home with school children are not included in this		Yes:

	program category; they are classified as education programs.		
Whole Home/ Audits	Residential audit programs provide a comprehensive, standalone assessment of a home's energy consumption and identification of opportunities to save energy. The scope of the audit includes the whole home although the thoroughness and completeness of the audit may vary widely from a modest examination and simple engineering-based modeling of the physical structure to a highly detailed inspection of all spaces, testing for air leakage/exchange rates, testing for HVAC duct leakage and highly resolved modeling of the physical structure with benchmarking to customer utility bills.		Yes
Whole Home/ Retrofit	Whole-home energy upgrade or retrofit programs combine a comprehensive energy assessment or audit that identifies energy savings opportunities with house-wide improvements in air sealing, insulation and, often, HVAC systems and other end uses. The HVAC improvements may range from duct sealing to a tune up to full replacement of the HVAC systems. Whole-home programs are designed to address a wide variety of individual measures and building systems, including but not limited to: HVAC equipment, thermostats, furnaces, boilers, heat pumps, water heaters, fans, air sealing, insulation (attic, wall, and basement), windows, doors, skylights, lighting, and appliances. As a result, whole-home programs generally involve one or more rebates for multiple measures. Whole-home programs generally come in two types: comprehensive programs that are broad in scope and less comprehensive, prescriptive programs sometimes referred to as "bundled efficiency" programs. This category addresses all of the former and most of the latter, but it excludes direct-install programs that are accounted for separately.		Yes:
Financing	Programs designed to provide or facilitate loans, credit enhancements or interest rate reductions/buy downs. As with other programs, included costs are utility costs, including the costs of any inducements for lenders, e.g., loan loss reserves, interest rate buy-downs, etc. Where participant costs are available for collection, these ideally will include the total customer share, i.e., both principal (the participant payment to purchase and install		Yes

	measures) and interest on that debt. Most of these programs will be directed toward enhancing credit or financing for residential structures.		
Other	Programs designed to encourage investment in energy efficiency activities in residences but are so highly aggregated (e.g., Existing Homes programs that include retrofits, appliances, equipment, etc.) and undifferentiated that they cannot be sorted into the residential program categories that are detailed in this document.		Yes: (Ex. Early Boiler Replacements)

Commercial Programs

Detailed category	Detailed program definition	Simplified category	Present or absent in NH Core
Audit	Programs in which an energy assessment is performed on one or more participant commercial facilities to identify sources of potential energy waste and measures to reduce that waste.	Custom	Yes
Custom	Programs designed around the delivery of site-specific projects typically characterized by an extensive onsite energy assessment and identification and installation of multiple measures unique to that facility. These measures may vary significantly from site to site. This category is intended to capture "whole-building" approaches to commercial sector efficiency opportunities for a wide range of building types and markets (e.g., office, retail) and wide range of measures.		Yes:
Commissioning/Retro-Commissioning	Programs aimed at diagnosing energy consumption in a commercial facility and optimizing its operations to minimize energy waste. Such programs may include installation of certain measures (e.g., occupancy monitors and switches), but program activities tend to be characterized more by tuning or retuning, coordinating and testing the operation of existing end uses, systems and equipment for energy efficient operation. The construction of new commercial/industrial facilities that includes energy performance commissioning should be categorized as "Com: New Construction". The de novo installation of		Yes

	energy management systems with accompanying sensors, monitors and switches is regarded as a major capital investment and should be categorized under "Com: Custom".		
Govt./Nonprofit/ MUSH	MUSH (Municipal, University, School & Hospital) and government and nonprofit programs cover a broad swath of program types generally aimed at public and institutional facilities and which include a wide range of measures. Programs which focus on specific technologies (e.g., HVAC and lighting) have their own commercial program categories Examples include incentives and/or technical assistance to promote energy efficiency upgrades for elementary schools, recreation halls and homeless shelters. Street lighting is accounted for as a separate program category.		Yes
Street Lighting	Street lighting programs include incentives and/or technical support for the installation of higher efficiency street lighting and traffic lights than the current baseline.		Yes
New Construction	Programs that incentivize owners or builders of new commercial facilities to design and build beyond current code or to a certain certification level (e.g., ENERGY STAR or LEED).		Yes: Although there is no ENERGY STAR Standard for new C&I buildings, Utilities do provide incentives for equipment above code / standard practice and will work with customer/architect on new building designs.

HVAC	C&I HVAC programs encourage the sale/purchase and installation of heating, cooling and/or ventilation systems at higher efficiency than current energy performance standards, across a broad range of unit sizes and configurations. Most of these programs will be directed toward commercial structures.		Yes
Lighting	C&I lighting programs incentivize the installation of efficient lighting and lighting controls. Typical measures might include T-8/T-5 fluorescent lamps and fixtures; CFLs and fixtures; LEDs for lighting, displays, signs and refrigerated lighting; metal halide and ceramic lamps and fixtures; occupancy controls; daylight dimming; and timers.		Yes
Performance Contracting/ DSM Bidding	Programs that incentivize or otherwise encourage energy services companies (ESCOs) and participants to perform energy efficiency projects, usually under an energy performance contract (EPC), a standard offer or other arrangement that involves ESCOs or customers offering a quantity of energy savings in response to a competitive solicitation/bidding process with compensation linked to achieved savings.		Yes: Directly thru EE incentiv es. (Some custome rs choose perform ance contracti ng, some ESCOs sell perform ance contracti ng.)
Prescriptive/IT & Office Equipment	Programs aimed at improving the efficiency of office equipment, chiefly commercially available PCs, printers, monitors, networking devices and mainframes not rising to the scale of a server farm or floor.		No: could be done via a Custom Measure .
Prescriptive/ Grocery	Grocery programs are prescriptive programs aimed at supermarkets and are usually designed around indoor and outdoor lighting and refrigerated display cases.		Yes
Other	Prescriptive programs that encourage the purchase and installation of some or all of a specified set of pre-approved measures besides those covered in other measure-specific prescriptive programs (e.g., HVAC and Lighting).		Yes:

Custom	Custom programs applied to small commercial facilities. (See definition of custom programs for additional detail.)		Yes
Prescriptive	Prescriptive programs applied to small commercial facilities. (See definition of prescriptive programs for additional detail.) Such programs may range from a walk-through audit and direct installation of a few pre-approved measures to a fuller audit and a fuller package of measures. Audit only programs have their own category.		Yes
Financing	Programs designed to provide or facilitate loans, credit enhancements or interest rate reductions/buy downs. As with other programs, included costs are utility costs, including the costs of any inducements for lenders, e.g., loan loss reserves, interest rate buy-downs, etc. Where participant costs are available for collection, these ideally will include the total customer share, i.e., both principal (the participant payment to purchase and install measures) and interest on that debt. Most of these programs will be directed toward enhancing credit or financing for commercial structures.		Yes:
Other	Programs not captured by any of the specific commercial program categories but are sufficiently distinct to the commercial sector to not be treated as a "Commercial/Industrial Other" program. Example: An EE program aimed specifically at the commercial subsector but is not clearly prescriptive or custom in nature.		Yes

Industrial /Agricultural Programs

Detailed category	Detailed program definition	Simplified category	Present or absent in NH Core
Audit	Programs in which an energy assessment is performed on one or more participant industrial or agricultural facilities to identify sources of potential energy waste and measures to reduce that waste.	Custom	Yes
Custom	Programs designed around the delivery of site-specific projects typically characterized by an extensive onsite energy assessment and identification and installation of multiple measures unique to that facility. These measures may vary significantly from site to site. This category is intended to capture "whole-facility" approaches to industrial or agricultural sector efficiency opportunities for		Yes

	a wide range of building types and markets		
Custom/ Data Centers	Data center programs are custom-designed around large-scale server floors or data centers that often serve high-tech, banking or academia. Projects tend to be site-specific and involve some combination of lighting, servers, networking devices, cooling/chillers, and energy management systems/software. Several of these may be of experimental or proprietary design.		Yes: via Custom Incentives. No specific program for Data Centers.
Custom/Ind. & Ag. Process	Industrial programs deliver custom-designed projects that are characterized by an onsite energy and process efficiency assessment and a site-specific measure set focused on process related improvements that may include, for example, substantial changes in a manufacturing line. This category includes all EE program work at industrial or agricultural sites that is process focused and not generic (and thus would be in the custom category) and not otherwise covered by the single-measure prescriptive programs below (e.g., lighting, HVAC, water heaters).		Yes: as part of a retro-commissioning project or a specific audit.
Custom/ Refrigerated Warehouses	Warehouse programs are typically aimed at large-scale refrigerated storage facilities and often target end uses such as lighting, climate controls and refrigeration systems.		Yes: via Custom incentives.
New Construction	Programs that incentivize owners or builders of new industrial or agricultural facilities to design and build beyond current code or to a certain certification level, e.g., ENERGY STAR or LEED.	New Construction	Yes: Although there is no ENERGY STAR Standard for new C&I buildings, Utilities do provide incentives for equipment above code / standard practice and will work with customer/architect on new building designs.
Prescriptive Industrial	Prescriptive programs that encourage the purchase and installation of some or all of a specified set of pre-approved industrial measures besides those covered in other measure-specific prescriptive programs on this list, e.g., industrial compressor programs.	Prescriptive	Yes: via Custom incentives.

Prescriptive/ Agriculture	Farm- and orchard-based agricultural programs that primarily involve irrigation pumping and do not include agricultural refrigeration or processing at scale.		Yes: via Custom incentives.
Prescriptive/ Motors	Motors programs usually offer a prescribed set of approved higher efficiency motors, with industrial motors programs typically getting the largest savings from larger, high powered motors (>200 hp).		Yes
Financing	Programs designed to provide or facilitate loans, credit enhancements or interest rate reductions/buy downs. As with other programs, included costs are utility costs, including the costs of any inducements for lenders, e.g., loan loss reserves, interest rate buy-downs, etc. Where participant costs are available for collection, these ideally will include the total customer share, i.e., both principal (the participant payment to purchase and install measures) and interest on that debt. Most of these programs will be directed toward enhancing credit or financing for industrial and/or agricultural facilities	All other IA	Yes (LU and UES)

Self Direct	Industrial programs that are designed and delivered by the participant, using funds that otherwise would have been paid as ratepayer support for all DSM programs. These programs may be referred to as "opt out" programs, among other names		No

Commercial/Industrial Programs

Detailed category	Detailed program definition	Simplified category	Present or absent in NH Core
Custom	Programs designed around the delivery of site-specific industrial and commercial projects typically characterized by an extensive onsite energy assessment and identification and installation of multiple measures unique to that facility. This category is for programs that address **both** the commercial and industrial sectors and cannot be relegated to one sector or another for lack of information on participation or savings.	Custom	Yes
New Construction	Programs that incentivize owners or builders of new commercial and industrial facilities to design and build beyond current code or to a certain certification level, e.g., ENERGY STAR or LEED. This category	New Construction	Yes: Although there is no ENERGY STAR Standard for new C&I buildings,

	should be used sparingly for those programs that cannot be identified with either the commercial or industrial sector on the basis of information available about participation or the source(s) of savings.		Utilities do provide incentives for equipment above code / standard practice and will work with customer/architect on new building designs.
Prescriptive	Prescriptive programs that encourage the purchase and installation of some or all of a specified set of pre-approved industrial and/or commercial measures but which cannot be differentiated by sector based upon the description of the participants or nature or source of the savings.	Prescriptive	Yes
Self Direct	Generally large commercial and industrial programs that are designed and delivered by the participant, using funds that otherwise would have been paid as ratepayer support for all DSM programs. This category is to be used for self-direct or opt-out programs that address both large commercial and industrial entities but which cannot be differentiated between these sectors because the nature and source of the savings is not available or is also too highly aggregated.	All other C&I	No
Mixed Offerings	Programs that cannot be classified under any of the specific commercial or industrial program categories and span a large variety of offerings aimed at both the commercial and industrial sectors.		Yes: via Custom incentives.
Other	Programs not captured by any of the specific commercial/industrial categories but are sufficiently distinct to the industrial and/or agricultural sectors to not be treated as a "Commercial/Industrial Other" program		Yes: via Custom incentives.

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Detailed category	Detailed program definition	Simplified category	Present or absent in NH Core
Codes & Standards (C&S)	In C&S programs, the PA may engage in a variety of activities designed to advance the adoption, application or compliance level of building codes and end-use energy performance standards. Examples	**Codes & Standards (C&S)**	Yes, part of Educati

	might include advocacy at the state or federal level for higher standards for HVAC equipment; training of architects, engineers and builder/developers on code compliance; and training of building inspectors in ensuring the codes are met.		on Programs. Utilities work with NHPUC Code person and provide Energy Code training to building code officials, builders, architects, etc. on both Code and "beyond code" construction techniques. Utilities are part of the NH Code Collaborative (nhenergycode.com)
Market Transformation (MT)	Programs that encourage a reduction in market barriers resulting from a market intervention, as evidenced by a set of market effects that is likely to last after the intervention has been withdrawn, reduced, or changed. MT programs are gauged by their market effects (e.g., increased awareness of energy efficient technologies	**Market Transformation (MT)**	Yes:

	among customers and suppliers); reduced prices for more efficient models; increased availability of more efficient models; and ultimately, increased market share for energy efficient goods, services and design practices. Example programs might include upstream incentives to manufacturers to make more efficient goods more commercially available; and point-of-sale or installation incentives for emerging technologies that are not yet cost effective. Workforce training and development programs are covered by a separate category. Upstream incentives for commercially available goods are sorted into the program categories for those goods (e.g., consumer electronics or HVAC).		
Workforce Development	Workforce training and development programs are a distinct category of market transformation program designed to provide the underlying skills and labor base for deployment of energy-efficiency measures.		Yes
Marketing, Education, Outreach (ME&O)	ME&O programs include most standalone marketing, education and outreach programs (e.g., statewide marketing, outreach and brand development). In-school energy and water efficiency programs are also included in this category, including those that supply school children with kits of prescriptive measures such as CFLs and low-flow showerheads for installation at home.	**Marketing, Education, Outreach (ME&O)**	Yes
Other	This category is intended to capture all programs that cannot be allocated to a specific sector (or are multi-sectoral) and cannot be allocated to a specific program type.		Yes
Planning/ Evaluation/ Other Programmatic Support	Non-ME&O support programs include the range of activities not otherwise accounted for in program-specific costs but needed for planning & designing a portfolio of programs and otherwise complying with regulatory requirements for DSM activities outside of program implementation. These activities generally are focused on the front and back end of program cycles, in assessing prospective programs; designing programs and portfolios; assessing the cost effectiveness of measures, programs and portfolios; and arranging for, directing or delivering reports and evaluations of the process and impacts of those programs - where those costs are not captured in program costs.		No Yes
Voltage Reduction/ Transformers	Programs that support investments in distribution system efficiency or enhance distribution system operations by reducing losses. The most common form of these programs involve the installation and use of conservation voltage regulation/reduction (CVR) systems and practices that control distribution feeder		No: Voltage Reduction and Power Factor

	voltage so that utilization devices operate at their peak efficiency, which is usually at a level near the lower bounds of their utilization or nameplate voltages. Other measures may include installation of higher efficiency transformers. These programs generally are not targeted to specific end users but typically involve changes made by the electricity distribution utility.		Correction are done via Engineering or Customers themselves (not EE) initiatives.
Shading/ Cool Roofs	Shading/reflective programs include programs designed to lessen heating and cooling loads through changes to the exterior of a structure (e.g., tree plantings to shade walls and windows, window screens and cool/reflective roofs). These programs are not necessarily specific to a sector.		Yes, via custom incentive
Multi-Sector Rebates	Multi-sector rebate programs include providing incentives for commercially available end-use goods for multiple sectors (e.g., PCs, HVAC).		Yes: HVAC No: PCs Yes via custom incentives.
Research	These programs are aimed generally at helping the PA identify new opportunities for energy savings (e.g., research on emerging technologies or conservation strategies). Research conducted on new program types or the inclusion of new, commercially available measures in an existing program are accounted for separately under cross-cutting program support.		Yes: via EEI, CEE, NEEP, ESource, Technical Assistance, and program administrators and installation contrac

			tors. One utility may pilot a new program or initiative (eg. CHP, Home Energy Reports, Wifi Tstats) prior to implementation as statewide.

Low income programs

Detailed category	.	Simplified category	Present or absent in NH Core
Low Income	Low-income programs are efficiency programs aimed at lower income households, based upon some type of income/means testing or eligibility. These programs most often take the form of single-family weatherization, but a variety of other program types also are included in this program category (e.g., multi-family/affordable housing weatherization, low-income direct-install programs).	**Low Income**	Yes

Demand Response Programs

Detailed category	Detailed program definition	Simplified category	Present or absent in NH Core
Time-of-Use Pricing	Demand-side management that uses a retail rate or Tariff in which customers are charged different prices for using electricity at different times during the day. Examples are time-of-use rates,	Pricing	No

	real time pricing, hourly pricing, and critical peak pricing. Time-based rates do not include seasonal rates, inverted block, or declining block rates.		
Critical Peak Pricing	Demand-side management that combines direct load control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.		No
Critical Peak Pricing with Load Control	Demand-side management that combines direct load control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.		No
Real-Time Pricing	Demand-side management that uses rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.		No
Peak Time Rebate	Peak time rebates allow customers to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days. Like Critical Peak Pricing, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.	Rebate	No
Other	Load management programs that are not captured by the specific DR categories named on this list.	Other	No

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