nationalgrid

Thomas R. Teehan
Senior Counsel

September 2, 2008

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Division Clerk
RI Division of Public Utilities & Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 3931 - Least Cost Procurement Plan

Dear Ms. Massaro:

Pursuant to R.I.G.L. §39-1-27.7, I have enclosed ten copies of the 2009-2011 Least Cost Procurement Plan prepared by National Grid.[1] This plan is submitted for approval by the Rhode Island Public Utilities Commission ("Commission") in compliance with the Least Cost Procurement Standards adopted by the Commission in Docket 3931.

The Least Cost Procurement Plan is comprised of an Energy Efficiency Procurement Plan and a System Reliability Procurement Plan. The Energy Efficiency Procurement Plan is the product of many meetings and discussions with the members of the Rhode Island DSM Collaborative, now functioning as a subcommittee of the Rhode Island Energy Efficiency Resource Management Council (EERMC). Both it and the System Reliability Procurement Plan are informed by the Energy Efficiency Resource Management Council's Opportunities Report.

The plan includes the following highlights:

- Doubling of energy efficiency savings, relative to 2008, by 2011
- Tripling of DSM expenditures, relative to 2008, by 2011
- Creation of over $280 million in net lifetime benefits for Rhode Island consumers
- A proposal to the Commission to authorize an increase in the DSM charge in 2009 by $0.0012/kWh to support the expansion of energy efficiency programs pursuant to least cost procurement
- Company commitment to file updated funding plans for 2010 and 2011 as more information on potential funding sources becomes available
- Definition of benefits and costs to be counted in the Total Resource Cost test
- Presentation of new energy efficiency program elements, delivery mechanisms, and financing approaches, including expansion of on-bill financing
- Equitable support of low-income energy efficiency programs by all market segments
- Commitment to work with the Office of Energy Resources on the development of small-scale renewables
- Expansion of demand response audits and incentives
- Targeting Aquidneck Island with a system reliability resource pilot program

[1] The Narragansett Electric Company d/b/a National Grid (hereinafter "Narragansett" or "Company").

While this Least Cost Procurement Plan is submitted by the Company alone, it reflects the input of many parties: the members of the Collaborative/Subcommittee[2], EERMC council members, and the EERMC team from VEIC. The Council itself voted to conditionally endorse the Energy Efficiency Procurement Plan at its meeting of August 14, 2008. Many of the Energy Efficiency Procurement Plan components represent areas of significant consensus among the Subcommittee members which, we hope, will lead their organizations to submit letters of support for many, if not all, elements of the Plan. Time did not permit consideration of the System Reliability Procurement Plan by the Subcommittee or the EERMC prior to the filing date.

Thank you for your attention to this filing. If you have any questions, please contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 3931 Service List

[2] Subcommittee members include representatives of National Grid, the Office of Energy Resources, TEC-RI, the Division of Public Utilities and Carriers, People's Power and Light (PP&L), and Environment Northeast.

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Certificate of Service

I hereby certify that a copy of the cover letter and/or any materials accompanying this certificate were electronically submitted to the individuals listed below. Due to the voluminous nature of this filing, National Grid will hand deliver the copies to the Commission in the a.m. (September 3).

Joanne M. Scanlon
National Grid

September 2, 2008
Date

Docket No. 3931 – RI Energy Efficiency and Resource Management Council ("EERMC") – Proposed Standards for Least Procurement Plan and System Reliability Procurement Plan
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2009-2011 ENERGY EFFICIENCY PROCUREMENT PLAN

SUBMITTED BY NARRAGANSET ELECRIC COMPANY d/b/a NATIONAL GRID

I. Introduction

"The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006" provides the statutory basis for least cost procurement in the State of Rhode Island. The general purposes of the act are (1) to provide Rhode Island residents, institutions and businesses the benefit of stability through diversification of energy resources, energy conservation, efficiency, demand management and prudent procurement; (2) to facilitate the development of renewable energy resources; (3) to make the cost of energy more affordable by mitigating demand and rates charged to low-income households; and (4) to strengthen energy planning, program administration, management, and oversight in a manner that is publicly accountable and responsive.

The legislation was intended to chart a new course for energy planning and procurement in RI as indicated in the following quote from House Majority Leader, Gordon Fox:

> " The new approach included in this bill establishes the next generation of energy planning and sets a new standard for how states should address energy planning ... It levels the playing field for energy efficiency and other lower-cost, consumer-friendly options, allowing them to compete equally with more traditional energy sources for the first time."[1]

The Comprehensive Energy Bill was created with input from Governor Carcieri's office and was originated in the Senate. On June 23, 2006, it passed both the House and the Senate unanimously, and on June 29th the Governor signed the bill into law.

Specifically, the Act provides for least cost procurement of system reliability and energy efficiency and conservation resources. System reliability procurement includes, but is not limited to, renewable energy resources, distributed generation, and demand response. Energy efficiency procurement includes "procurement of energy efficiency and energy conservation measures that are

[1] RI general Assembly press release 2/29/06

prudent and reliable and when such measures are lower cost than acquisition of additional supply, including supply for periods of high demand."[2]

The Act further requires that "each electrical distribution company shall submit to the Commission on or before September 1, 2008, and triennially on or before September 1, thereafter through September 1, 2017, a plan for system reliability and energy efficiency and conservation procurement."[3] The Act specifies that the plan should include "measurable goals and target percentages for each energy resource, pursuant to standards established by the Commission, including efficiency, distributed generation, demand response, combined heat and power, and renewables."[4] This plan is submitted in fulfillment of that requirement by The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company").

As required by the Act, draft Standards for governing energy efficiency and system reliability procurement were proposed by the Energy Efficiency and Resources Management Council ("EERMC" or "Council"), a stakeholder oversight board appointed by the Governor and also pursuant to the Act comprised of representatives from "(1) energy regulation and law; (2) large commercial/industrial users, (3) small commercial/industrial users; (4) residential users; (5) low income users; (6) environmental issues pertaining to energy; and (7) energy design and codes." In preparing the draft Standards, the EERMC consulted with TEC-RI, Environment Northeast, the Office of Energy Resources, the URI Partnership for Energy, and the Company and held informational meetings with the Rhode Island Division of Public Utilities and Carriers. The Commission then opened Docket 3931 "Standards for Energy Efficiency and Conservation Procurement and System Reliability" and issued a Notice of Public Hearing. After accepting motions to intervene, holding a public hearing, accepting public comments, and receiving testimony from interested parties, the Commission issued a final set of Standards at Open Meeting on June 12, 2008. The Standards are included in Attachment A to this plan.

Consistent with the 2006 Act, the Standards require the Company to submit a three year Energy Efficiency Procurement Plan by September 1, 2008 that "shall identify strategies and an approach to planning and implementation of programs that will secure all cost-effective energy efficiency resources that are lower cost than supply and are prudent and reliable."[5] All plans regarding procurement of system reliability and energy efficiency procurement in Rhode Island must be built

[2] RIGL §39-1-27.7
[3] RIGL §39-1-27.7
[4] RIGL §39-1-27.7
[5] Standards Section 1.2 A

upon the foundation of what has been implemented in the years preceding the development of the plan. In particular, for energy efficiency, the Company has a twenty year track record of continuous and successful implementation of energy efficiency programs that should play a key part in shaping the development of future efforts. The Standards require that the EE Procurement Plan "shall describe the recent energy efficiency programs offered by the Utility and highlight how the EE Procurement Plan supplements and expands upon these offerings."[6]

This Plan is the product of long and substantive discussions among the members of the EERMC Subcommittee. The Subcommittee includes representatives from the Division of Public Utilities and Carriers, Environment Northeast, National Grid, the Office of Energy Resources, People's Power and Light, and TEC-RI, as well as members of the Council and the Council's consultant team from Vermont Energy Investment Corporation. The Council members who have participated in the Sub-Committee process over the past months include Chris Powell (Large Commercial/Industrial Users), Dan Justynski (Small Commercial/Industrial Users), Joe Cirillo (Energy Design and Codes), Sam Krasnow (Environmental Issues), and Joe Newsome (Low Income Users). The Plan was submitted by the Subcommittee to the Council for its consideration at its meeting of August 14, 2008, and was endorsed by the Council at that meeting[7].

II. Funding Plan

Consistent with the goals of the Standards and the Act, the Company plans to double the amount of savings for RI customers produced by its electric energy efficiency programs, relative to 2008, over the three years from 2009 through 2011 through the implementation of programs that are lower than the cost of supply and are prudent and reliable. The projected cumulative amount of 265,000 net annual MWh savings over the three years is 90% of the "Aggressive Achievable Case" for energy efficiency procurement over the same period presented in Table 1-2 of KEMA's "The Opportunity for Energy Efficiency that is Cheaper than Supply in Rhode Island: Phase I Report – Submitted July

[6] Standards, Section 1.2 A. 1. b.

[7] The Council voted to approve the Plan with the following provisos: (a) that the section regarding the proposed incentive to National Grid be removed and (b) that the approval of the plan is preliminary and that the EERMC reserves the right to comment further even if the comments are negative. As noted below in section G, proviso (a) is moot, since the Company subsequently altered its incentive proposal from what was presented to the Council.

15, 2008 (The 'Opportunities Report')" to the EERMC.[8] Table 1 summarizes the savings goals, budget, and economic benefits for the three year plan, compared to 2008.

The Company's savings goals for the three-year procurement plan establish a balance between the opportunities identified in the Opportunities Report and the leveraging power of Least Cost Procurement, with the standard of prudency for procurement that is also contained in the Rhode Island statute. In particular, it is important during the first three years of least cost procurement, to create the delivery infrastructure and financing mechanisms to enable the planned program expansion to proceed in a realistic and sustainable manner and to ensure the quality of installations that will ensure continued optimum energy-savings performance of the installed equipment. This is a strategy for Rhode Island, consistent with the Act and the Standards that is at once about dramatic energy cost savings, job creation, and reliability. The proposed three year Energy Efficiency Procurement Plan will deliver lifetime net energy savings of more than $281 million for Rhode Island ratepayers[9].

Table 1

2009-2011 Energy Efficiency Procurement Plan: Summary of Benefit, Costs, Savings ($000)

	2008	2009	2010	2011	3 Year Total
NPV Net Benefits ($000)	$60,341	$78,278	$93,458	$109,866	$281,602
NPV Utility Costs ($000)	$14,861	$24,430	$34,739	$43,296	$102,4661
TRC Benefit / Cost	4.00	3.22	2.95	2.83	2.97
Annual Energy Savings (MWh)	54,268	74,387	88,546	102,566	265,499
Annual kW	9,154	12,555	15,154	17,815	45,524
Lifetime MWh	636,784	893,011	1,084,987	1,272,891	3,250,888
Cost / Lifetime kWh	$ 0.032	$ 0.039	$ 0.044	$ 0.047	$ 0.044

Notes: Net benefits = benefits - (participant costs + utility costs - shareholder incentive)
Utility costs exclude shareholder incentive
TRC Benefit/Cost includes shareholder incentive as a cost

A three year funding plan for the Energy Efficiency Procurement is included as Attachment B. This plan first shows the sources of funding that are currently available to fund the energy efficiency programs: DSM charge collected at the current rate of $0.002/kWh, fund balance interest,

[8] The Opportunities Report notes that the estimate of achievable potential "generally assumes traditional program approaches and consequently is a provisional first step but not definitive of what is actually achievable under Rhode Island law. This is because under Least Cost Procurement it is possible to leverage higher savings through bolstered marketing, financing, and community based delivery strategies (page 1-6)."

[9] This estimate of net benefits is based on value components available at the time the Company prepared this plan. The Company is in the process of updating some assumptions—notably avoided transmission and distribution capacity value, water and sewerage value, and discount rate—that may affect the net benefits to be included in the Energy Efficiency Program Plan.

commitments from prior years, customer co-payments received by the Company, and ISO-New England capacity market revenue.

In accordance with the requirement of Standards Section 1.2 A to "identify strategies and an approach to planning and implementation of programs that will secure all cost-effective energy efficiency resources that are lower cost than supply and are prudent and reliable," the Company seeks the Commission's approval of the three-year funding plan's overall spending targets and goals, shown in Part A of Attachment B. In order to double the amount of savings from the programs to achieve $281 million in net energy savings, the Company projects the need for approximately $134 million in funding over the three-year period. This is $71 million in funding more than what the funding would be over the same period using only the current sources of funding and maintaining only the current level of efforts. The total funding translates to $102 million in efficiency program implementation and evaluation expenses over the three year period[10], $58 million more than what the expenses would be over the same period at current levels of effort. Supplemental funding is needed to secure efficiency resources that are less costly than supply in compliance with the 2006 Comprehensive Energy Bill and 2008 Procurement Standards and to generate lifetime net energy savings of more than $281 million for Rhode Island ratepayers.

There are many uncertainties associated with the exact amount of the additional funding that will be needed: Company sales, customer co-payments, commitments made for future years, the settlement price for future Regional Greenhouse Gas Initiative (RGGI) and forward capacity market auctions, the allocation of auction proceeds to the Company's energy efficiency programs, and the Company's success in implementing least cost procurement of energy efficiency.

Because of these uncertainties, the Company proposes in this Procurement Plan to make a specific request for the funding necessary only for the 2009 program year; the Company, after consultation with the Subcommittee, intends to return to the Commission with specific requests for 2010 and 2011, as the uncertainties become less uncertain. The Company proposes to secure the supplemental funding for 2009, in compliance with the adopted standards, through an increase under the existing DSM charge—also known as the systems benefit charge—mechanism (as allowed under R.I.G.L. Section 39-2-1.2). We propose the Commission consider an increase in the DSM charge of $0.0012/kWh for 2009. This would establish the total DSM charge at $0.0032/kWh in 2009. Part B of Attachment B shows the calculation of the incremental funding needed to

[10] The difference between funding and utility implementation and evaluation expenses are commitments to future years, co-payments expected to be received during the program year, and the target shareholder incentive.

support the Procurement Plan. Part C of Attachment B shows the estimated savings and lifetime cost per kWh for the three year period.

This proposal assumes no allocation of RGGI funds to energy efficiency in 2009. The Company and several other subcommittee and Council members support the allocation of RGGI funds to the Company's energy efficiency programs. The R.I. General Laws § 23-82-6 establishes that such proceeds shall be used to benefit energy consumers "through investment in the most cost-effective available projects that can reduce long-term consumers energy demands and costs" and mentions energy efficiency several times in that regard. Other RGGI states have also taken this same approach. However, the ultimate decision about the allocation of RGGI auction proceeds resides with the OER, with input from the DEM and the EERMC. A decision about the allocation of RGGI funds has not yet been made, and the timing of this decision is unknown. Therefore, we further propose that if it is decided to allocate RGGI funds to the Company's programs, the Company will file a proposal with the PUC for an adjustment to the funding plan for 2009.[11]

As with the current funding mechanism, should there be surplus energy efficiency funds at the end of 2009, we propose that these funds, as well as the interest generated by them, be carried over into 2010 and allocated to the programs in that year. If there is carryover, it will reduce any increase in the DSM charge that may be needed for 2010.

While Attachment B does not show sector-specific funding levels, the Company proposes that the energy efficiency programs offered to the low-income sector be subsidized by all the other sectors: residential, small business, and large commercial and industrial. This is a departure from prior years' practice of funding the low-income programs primarily from the residential sector, but is important to providing equitable and sustainable opportunities to all sectors for energy efficiency procurement. The allocation mechanism needs to be developed. At the same time, the programs may be viewed as a tool for economic development. Funding for low-income and economic development will provide a measure of equity in the availability of program funds, which is identified as a desirable objective in the adopted Least Cost Procurement Standards.

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[11] This adjustment could be n elimination or reduction in the increase in the DSM charge or it could be to maintain the DSM charge at the proposed $0.0032/kWh and accumulate the funds from the RGGI auction for use in the 2010 program year to mitigate further increases in the DSM charge that would be needed to support further program expansion in 2010 and/or 2011. Note that an allocation in 2009 of funds equivalent to 90% of the RGGI auction at an estimated allowance p[rice of $5/ton to the energy efficiency programs would eliminate the need for the proposed DSM charge increase. This allocation would also greatly reduce the need for increases in the DSM charge in 2010 and 2011 illustrated in Attachment B. At the proposed program levels a 90% RGGI allocation at $5/ton would mean only roughly a .0009 and .0019 increase is needed in 2010 and 2011.

The Company intends to work with various market actors to leverage the expenditure of funds it controls in order to achieve program savings goals while controlling costs. The Company has not sufficiently developed these strategies to incorporate them into this Plan. Future updates to this procurement plan will reflect progress made in leveraging other sources of funding and will be included in the November 1 annual Energy Efficiency Program Plan filing. The Company will consider partnering with lending institutions that could make attractive financing terms available given that the Company has a unique and ubiquitous way to bill and collect payments. Other sources of funding to be leveraged include vendors or manufacturers who would benefit from expansion of the energy efficiency industry in Rhode Island.

The Company intends to expand its use of on-bill financing to remove some of the barriers that exist to program participation. On-bill financing is currently used in the small business sector, where the Company pays 70% of the installation cost, and customers may elect to pay their portion up front or over one or two years through monthly payments on their electric bills. No interest payments are made with the on-bill payments, so this is essentially a zero percent loan. The Company plans to expand on-bill financing to advance energy efficiency in cities and towns, which are typically capital-constrained. Initially, the Company would propose a cap on the amount of money it would make available to support on-bill financing.

III. Procurement Components

A. Introduction

The Company expects that energy efficiency procurement under this Plan will be a combination of expanding current program offerings, supplementing current program offerings with new programs or technologies, and exploring new mechanisms to reach the market with energy efficiency consistent with the Commission's Standards. This section outlines, by sector, proposed strategies to supplement and build upon the initial EERMC Opportunity Report – Phase I; new strategies to make available the capital needed to implement projects in addition to the incentives provided; and plans to integrate gas and electric energy efficiency programs to optimize customer energy efficiency. Details on proposed program offerings for 2009 will be provided in the Energy Efficiency Program Plan, due to be filed by November 1, 2008. Inclusion of specific new directions from among those identified below in the Program Plan may be dependent on program- or measure-specific cost-effectiveness determination and timely development of appropriate delivery infrastructure.

B. Residential Sector

1. The Company has offered a number of programs targeted at the Residential Sector

    a. The low income program, marketed as the Appliance Management Program, is delivered by the State Energy Office and local Community Action agencies. It provides the same services as the EnergyWise program, described below, but no customer contribution is required for equipment installation.

    b. The EnergyWise program offers customers free home energy audits and information on their actual electric usage. Participants in this program receive financial incentives to replace inefficient lighting fixtures, appliances, thermostats, and insulation levels with models that are more energy efficient. The program addresses baseload electric use as well as electric heat in all residential buildings.

    c. The ENERGY STAR Products program includes the ENERGY STAR Appliance Program which promotes the purchase of high efficiency major appliances (refrigerators, dishwashers, clothes washers, room air conditioners, and dehumidifiers) that bear the ENERGY STAR Label. It is offered by several utilities throughout the region.

    d. The ENERGY STAR Lighting program is an initiative implemented jointly with other regional utilities. It provides discounts to customers for the purchase of ENERGY STAR compact fluorescent lamps and fixtures through instant rebates, special promotions at retail stores, or a mail order catalog.

    e. The ENERGY STAR Heating program assists homeowners purchasing or replacing an existing oil or propane heating system with a qualifying ENERGY STAR heating system. Funding is provided by the Company and administered by the State Energy Office.

    f. The ENERGY STAR Air Conditioning program promotes the installation of high efficiency central air conditioners. The program provides training of contractors in installation, testing of the high efficiency systems, tiered rebates for new ENERGY STAR systems, and incentives for checking existing systems.

g. The Company promotes energy education in schools through the National Energy Education Development (N.E.E.D) Program. This program provides curriculum materials and training for a comprehensive energy education program. The Company also supports the ENERGY STAR Homes Vocational School Initiative which trains students at the nine Rhode Island Career and Technical schools to be ENERGY STAR certified builders.

h. The ENERGY STAR Homes Program promotes the construction of energy efficient homes by offering technical and marketing assistance, as well as cash incentives to builders of new energy efficient homes that comply with the program's performance standards.

2. New program directions

   a. Heating, Ventilation, Air Conditioning, Water Heating and Building Envelope

      - Micro CHP - net metering needs to be resolved
      - Room Air Conditioning upgrades including Ductless mini-splits, Room Air Conditioning retrofit kits and Multifamily RAC change outs. Increased Central AC incentives and review cost effectiveness of incentives for brushless motor applications, ENERGY STAR quality installation verification, incentives for air flow improvements, and early replacements
      - Direct load control devices
      - Upgrade thermal measures, including flat roof applications, exterior insulation and finish systems, interior rigid foam, and high expansion foam and consider window film for central air and electric heating customers
      - HVAC occupancy sensors (for example for use in time-share type facilities)
      - Energy management systems for multifamily central A/C with wireless networked programmable controls
      - High performance Window/door replacement
      - Pool covers in enclosed spaces whatever the pool heat source (reduce dehumidification requirements)
      - Parking garage retrofit CO sensors to control exhaust fan speed and on-time

- Flow testing, flow dampening retrofits and duct sealing for stacked exhaust, dampers, actuators, and duct reconfiguration for rooftop make-up air and exhaust, ventilation systems
- Awnings and Vestibule additions
- Cool roofs
- Heat pump water heaters and GFX drain water energy recovery
- Geothermal heating retrofit
- Ground source heat pumps for retrofit

b. Residential Appliances and Lighting

- Residential ENERGY STAR electronics (TVs, set top boxes, video) and appliances, room air conditioners (RAC), dehumidifiers, torchieres, and behavioral education
- Smart strips - Green strips
- Second refrigerator bounty program - RAC turn-in events (this was featured in the Opportunities Report)
- In-home display units informing customers of power consumption in real-time
- Replacement of laundry equipment (front loading washers, etc.) including Energy Star washers and dryers for common laundries
- Advanced lighting technologies – LED

c. New Construction

- Zero energy homes
- Geothermal heating for residential
- Ground source heat pumps for new construction, peak cooling

d. Renewables

- Solar measures - PV, electric solar DHW, and potential pairing with other high value items as an incentive for participation.

e. Introduce a direct load control program, as recommended by the Opportunities Report

3. Integration with Gas Programs

The Company has been working to integrate the gas and electric residential energy efficiency programs since the gas programs were launched in July 2007.

The Company will seek a higher level of flexibility in program administration to allow for transfer of funds, if necessary, between budgets to allow for integrated services to be delivered.

C. Small and Medium Business

1. Description of recent energy efficiency programs offered by the Company

For over ten years, this program has provided direct retrofit installation of energy efficient lighting, refrigeration and other energy efficient measures to small commercial and industrial customers. Any customer with an average monthly demand of less than 200 kW or annual energy usage of less than 483,600 kWh is eligible for this program. The Company arranges the equipment purchase through a material vendor and installation with an administrative contractor. Customers pay 30% of the cost of installations and the Company pays the balance. Customers may finance the remainder for up to 24 months interest-free through their electric bill. If customers pay their portion up front, they receive a 15% discount off the amount due.

2. New program directions

   a. Introduce a direct load control program, as recommended by the Opportunities Report

   b. Emerging technologies such as LED lighting

3. Integration with Gas Programs

   a. Small Business Services (electric) incorporating prescriptive measures now offered through the High Efficiency Heating program, GasNetworks, and the Commercial Energy Efficiency Program (insulation, controls, stream traps, for example). At this point, the Small Business Program offers a turnkey audit and installation service for electric energy saving measures. On the gas side, audits are done and then additional services/analyses are done if measures are more complex.

   The types of measures offered by the electric program are: lighting, thermostats, and custom measures. The types of gas measures that could be considered "retrofit" are steam traps, thermostats, boiler re-set controls, and attic insulation. There are a number of different options to explore.

- Audit for both gas and electric opportunities at the same time, install electric measures, and leave behind rebate applications for gas measures: Audits would be seamless to the customer. To achieve this, auditors would have to be trained. Also, since customers are used to direct installation, there may not be follow-through on installation of gas measures. Finally, eligibility rules would have to be reviewed because some "small" electric customers may be large gas consumers.

- Direct installs for both electric and gas measures: Alternatively, a turnkey solution could be offered on both gas and electric measures. This turnkey capability does not currently exist on the gas side. Also, eligibility would have to be reviewed, as described above. Additional subcontractors will be needed to install measures like steam traps and insulation.

D. Large Business

1. Description of recent energy efficiency programs offered by the Utility

Design *2000plus* promotes energy efficient design and construction practices in new and renovated commercial, industrial, and institutional buildings. The program also promotes the installation of high efficiency equipment in existing facilities during building remodeling and at the time of equipment failure and replacement. Design 2000plus is known as a lost opportunities program because a customer who does not install energy efficient equipment at the time of new construction or equipment replacement will likely never make the investment for that equipment or will make the investment at a much greater cost at a later time.

Design 2000plus provides both technical and design assistance to help customers identify efficiency opportunities in their new building designs and to help them refine their designs to pursue these opportunities. The program also offers rebates to eliminate or significantly reduce the incremental cost of high efficiency equipment over standard efficiency equipment. Commissioning or quality assurance is also offered to ensure that the equipment and systems operate as intended.

Energy Initiative is a comprehensive retrofit program designed to promote the installation of energy efficient electric equipment such as lighting, motors, heating, and ventilation and air conditioning (HVAC) systems in existing buildings. All commercial, industrial, and institutional customers are eligible to participate. The Company offers technical assistance to customers to help them identify cost-effective conservation opportunities, and pays rebates to assist in defraying part of the material and labor costs associated with the energy efficient equipment.

2. New program directions
   a. Codes
   b. Expand the retrocommissioning program, as proposed in the Opportunities Report.
   c. Cool Choice and Energy Initiative HVAC controls (electric) and High Efficiency Heating and GasNetworks (gas): More work needs to be done promoting both our gas and electric incentives to installers, building design engineers, and equipment distributors.

3. Integration with Gas Programs
   a. InDemand program tracking system: A gas program tracking system is being developed using InDemand currently used by electric programs
   b. Comprehensive Design Approach, Advanced Buildings and Schools Initiative (electric); Commercial Energy Efficiency Program; and Emerald Network (gas): The nature of these programs under Design 2000plus is to look at how design elements of a new building interact with one another regardless of input energy type. Already, we have looked at a number of projects where potential gas and electric energy savings measures were analyzed. This seems to be working well. Technical Assistance studies (electric) and co-funded engineering studies (gas) need to be better aligned (herein called technical services).
   c. Industrial Processes through Energy Initiative and Design 2000plus (electric) and Commercial Energy Efficiency Program (gas): While not common, there could be opportunities where there are gas and electric savings for a new industrial process.
   d. Retro-Commissioning/Whole Building Assessment: These programs have been successful electric programs. They both look at electric, gas and oil opportunities. It's still early but the current cue of projects has not yielded any significant energy efficient

measures to be funded by gas programs. Likely many no or low cost O&M measures are recommended and implemented that save therms. For technical services, the electric pays 75% for Retro-commissioning and 50% for WBA (and 100% if the customer proceeds with capital projects where incentives are involved). The gas programs only pay up to 50%. As described previously, technical services under the gas and electric programs need to be better aligned so as to be seamless to the customer.

E. Other Elements of the Plan

1. Ramping up strategy:

As mentioned previously, the Company is committed to doubling the amount of savings achieved through the energy efficiency programs. This commitment will require expansion of the workforce in Rhode Island involved with energy efficiency program implementation as well as the development of innovative program delivery mechanisms. These will be presented in the annual Energy Efficiency Program Plans as they are developed The Company is confident that it will be able to achieve this ramp-up rate over the three-year period in a way that is sustainable and reliable.

2. Equity:

It is important to note that procurement of all cost-effective energy efficiency allows for the development and implementation of programs of varying TRC- test benefit-cost ratios (as long as the programs are cost effective); it does not mean implementing the programs with the highest TRC first. This provision facilitates equity in the energy efficiency programs. Equity has been and will continue to be an important element of program design. All customers contribute to the energy efficiency fund and, therefore, programs will be made available to all customers. This will be reflected in the forthcoming Program Plan. In particular, the Company expects to continue to offer programs to low-income customers, and it expects to propose program elements for economic development. With the proposed subsidization of the low-income sector by all other sectors, some of the funding constraints experienced in prior years will be removed.

3. Interaction with the System Reliability Procurement Plan:

a. The System Reliability Procurement Plan accompanies this Energy Efficiency Procurement Plan. The two plans interact in the areas of proposed direct load control (DLC), renewables, and combined heat and power (CHP) elements. The Company sees some linkage between the DLC component of the proposed Aquidneck Island pilot and this plan, and will explore funding some portion of the DLC in the pilot from energy efficiency funds. For renewables, the Company will investigate the use of rebates to promote geothermal installations, if they prove to be cost effective. Finally, CHP support is currently available through the Company's gas energy efficiency program. The 2009 Program Plan will continue to promote CHP installations.

4. Discussion of Cost effectiveness criteria:

   a. This plan is based on the 2007 Avoided Cost study. We expect to update it in 2009 after the next avoided cost study is completed.

   b. The standards prescribe the use of the TRC test. It may be reasonable in some cases (pilots programs, training/education programs, marginally not-cost-effective programs) to fund programs that fail the TRC test, as long as the portfolio passes the test. These programs are supported because they will serve the long term objective of the legislation.

F. Budgets and Goals:

The preliminary budget and goals for the Procurement Plan are summarized above in Table 1. The budget in Table 1 includes Utility Costs but does not include the costs of the proposed utility shareholder incentive[12]. These goals are presented at the portfolio level, as required by the Standards. They identify projected costs, benefits, initial energy saving goals of the portfolio for each year, and the projected cost effectiveness of the portfolio of energy efficiency programs using a Total Resource Cost (TRC) test as well as the projected cost of efficiency resources in cents/ lifetime kWh. The benefits are assessed using a TRC Test perspective, as specified in the adopted Standards. A detailed discussion of program benefits and costs is included in Attachment C. Program specific budgets, benefits, and goals will be filed as part of the Energy Efficiency Program Plan on or before November 1, 2008.

[12] The budget including the costs of the proposed incentive is included in "Total Funding to Meet Goals" in the Funding Plan in Attachment B.

G. Efficiency Performance Incentive Plan:

As specified in the adopted Least Cost Procurement Standards, the "Utility shall have an opportunity to earn a shareholder incentive that is dependent on its performance in implementing the approved EE Procurement Plan...The Utility, in consultation with the Council, will propose an incentive proposal that is designed to promote superior Utility performance in cost-effectively and efficiently securing for customers all efficiency resources lower cost than supply."

1. Background

The current shareholder incentive in Rhode Island establishes an incentive dollar value that is a percentage of the spending budget. The Company earns the shareholder incentive based on how well it meets its kWh savings goal, and how efficiently it spends the budget to do so. In addition, there are five performance metrics for other objectives consistent with the savings goals. Details on the current incentive structure are provided on pages 11 through 14 of the "Settlement of the Parties for Electric Demand Side Management Programs for 2008."

2. Proposed Shareholder Incentive for 2009

As directed by the Standards, the Company and the EERMC Subcommittee have reviewed incentive mechanisms in other jurisdiction as well as the existing Rhode Island Mechanism. It is the Company's opinion that an alternative mechanism would better align the Company's financial interests with the pursuit of energy efficiency beyond the levels historically pursued, consistent with the expectations of Least Cost Procurement, while controlling costs to the extent feasible. Consistent with this view, the Company proposed alternatives to the current Shareholder Incentive mechanism with the Subcommittee. However, the Company and the Subcommittee were not able to reach an agreement on an alternative. While the Company believes it is important to develop a new mechanism, it also believes that it is critical to begin the essential work of increasing the scope and size of it energy efficiency programs and to focus on the programmatic components of least cost procurement.

Therefore, the Company proposes for 2009 to retain the shareholder incentive mechanism that was approved for 2008 in Docket 3892. The Company is proposing this incentive mechanism for use in 2009 to allow time for consideration of other alternative mechanisms for 2010 and 2011. In that regard, the Company intends to revisit the issue of an alternative shareholder incentive mechanism with the Subcommittee and reserves the right to file for approval of an alternative mechanism at the appropriate time that would apply for 2010.

The shareholder incentive mechanism for 2008 proposed for use in 2009 is presented below:

The shareholder incentive mechanism will continue to include two components: (1) kWh savings targets by sector and (2) performance-based metrics.

A. kWh Savings:

A target incentive rate of 4.40% will be applied to the eligible spending budget for 2009. The projected spending budget for 2009 is approximately $24.2 million (see Attachment B). The total target incentive for 2009 would be 4.40% of the approved spending budget, or approximately $1,065,000 (see Attachment D). Of this total, $100,000 will be the target incentive for the performance-based metrics and the remainder will be for the kWh savings target.

The threshold performance level for energy savings by sector will remain at 60% of the annual energy savings goal for the sector. The Company must attain at least this threshold level of savings in the sector before it can earn an incentive related to achieved energy savings in the sector. The Company will have the ability to earn an incentive for each kWh saved, once threshold savings for the sector are achieved, up to 125% of target savings.

The incentive cap on energy savings will be equal to 125% of the target incentive amount for energy savings. If the Company achieves this level of exemplary performance, Rhode Island consumers will realize additional savings. Given budget control requirements, this will provide the Company with an incentive to improve the efficiency of its program implementation efforts while providing Rhode Island consumers with value in excess of the incremental incentive that may be earned by the Company.

Final sector spending budgets and savings goals will be provided in the Energy Efficiency Program Plan. Energy savings goals by sector will reflect the expected cost of savings in each sector informed by evaluation studies and will be adjusted to take into account changing rebate policies, the changing market being served, and the proposed expansion of program efforts in 2009. These goals will be carefully reviewed by the Subcommittee to ensure that they represent reasonable and challenging goals for the year.

There are three circumstances that would necessitate the recalculation of the threshold, calculated cap, and incentive for a particular sector:

1. If budgets are adjusted as a consequence of a true up filing in May 2009 (only under the condition that the actual 2008 year end fund balance deviates from projections by more than 20%, as described above, and only then with Commission approval), the threshold and incentive for the affected sectors will be adjusted as will each sector's incentive caps.

2. If the assumptions used to develop savings goals change as a result of evaluation studies completed by September 30, 2009, the Company will recalculate savings goals to account for those evaluation findings and will report actual savings on the same basis.

3. If the actual spending in a sector at year end is greater than or less than the spending budget by more than five percent, the savings goal for that sector will be adjusted by the ratio of actual spending to the spending budget.

None of these changes will affect the target incentive dollars associated with performance metrics. The Company will report program results compared to these revised budgets and goals in its Year-End Report regarding 2009 DSM Program efforts.

B. Performance Metrics

Up to five performance-based metrics will be proposed for 2008, including two that relate to the Residential sector, one that relates to the Small Commercial and Industrial sector, and two that relate to the Large Commercial and Industrial sector. The Company will have the ability to earn $20,000 for each performance metric it successfully achieves in 2009. Some of the metrics may afford the opportunity to earn a portion of the incentive for partially achieving goals. The total potential incentive for performance metrics is capped at $100,000. Specific metric proposals for 2009 will be included in the Energy Efficiency Program Plan.

2009-2011 SYSTEM RELIABILITY PROCUREMENT PLAN

SUBMITTED BY NARRAGANSETT ELECRIC COMPANY d/b/a NATIONAL GRID

As a part of the larger Least Cost Procurement (LCP) plan, this System Reliability Procurement Plan (SRP), if approved, would provide the first of many pilots to use Alternate Resource Technologies (ARTs) as an alternative or an enhancement to proposed distribution and/or transmission upgrades. These sources include; targeted energy efficiency, demand response including direct load control (DLC), renewable energy generation, and combined heat and power (CHP). For all the ARTs above, analyses would be conducted to determine the cost/benefit of these sources, the affect on end-user price stability, their ability to broaden the fuel diversity used in RI, and the environmental benefits gained from the use of these resources. The costs for this plan would be recovered from RI customers through the necessary filings reviewed and approved by the Public Utilities Commission.

1. CHP

In reviewing NESCAUM's CHP opportunity report, the Company sees that there is economic potential of over 300 MWs of CHP in the state. The report clearly states that without the proposed phase 2 study, this number is still tentative.

The Company has begun offering a gas energy efficiency incentive for CHP. As part of the filing at the Commission, an evaluation was proposed in order to determine the overall cost/benefit of CHP. This cost/benefit analysis would determine actual annualized efficiencies of projects receiving incentives. The annualized efficiency is critical to determine how the CHP measures up against the emissions and efficiency characteristics of the standard alternative of grid power and use of an on-site boiler. This evaluation would be used as an input to the SRP to provide guidance as to the parameters required for CHP. The Company also has promoted the installation of some micro-CHP to residential and small commercial customers.

2. Renewables

In reviewing URI's small scale renewables opportunity report, it appears that offering a credit for photovoltaics (PV) of 150% of the retail price of electricity could provide enough incentive for customers to install more PV. Another option that could provide a similar benefit would be to offer a retail credit, but based on actual hourly commodity prices instead of the current flat standard service offering. The Company could offer an hourly pricing option to customers with PV to determine if this meets the criteria above.

The Company offers an incentive to solar thermal installations for gas water heating customers through its gas efficiency program, and could look to expand this to customers with electric water heating.

With the small amount of hydro potential, case-by-case incentives could be provided to encourage development of these projects.

The Company is investigating the use of rebates to promote geo-thermal installations under its Energy Efficiency plan.

The Company proposes to work with OER to determine how best to promote renewables. Some ideas not listed above: fund additional wind studies; providing a $/watt PV incentive; and providing on-the-bill financing for renewable projects.

3. Demand Response

This service supports participation of our customers in ISO-New England's forward capacity market (FCM) and demand response programs as well as in areas targeted by the Company for local load relief. Its goal is to help customers efficiently deploy existing and emerging efficiency technologies and strategies to manage their energy costs as well as reduce electrical load during peak hours (typically summer) throughout the Company's service territory. If this load relief can be targeted to a specific area, this reduction may defer capital investments in the distribution system, assist in stabilizing electricity costs and improve the reliability of the local electrical grid.

With the bulk of demand response in New England contracted from customers by third party demand response providers (i.e. Enernoc, ConsumerPowerline, Comverge, etc.), it is critically important that the Company have access to ISO-NE data as to what resources are available in certain areas on the Company's distribution system. This information could provide relatively low cost assets to respond to Company emergency conditions to better manage the system. The rationale is that the customers are already contracted to respond, and for minimal costs could be asked to respond to a Company request.

Company interest in targeted demand response

The Company has been actively promoting the current generation of targeted demand response programs since 2002. There are a number of design elements that facilitate the development of a targeted demand response program in a specific area. The first element is a capacity shortfall on transmission system over the course of the project. Due to the nature of distribution and transmission system planning and the lead time for construction projects to be planned and completed, the Company works to select an area which is not in imminent danger of insufficient capacity even without the specific distribution or transmission upgrade, but in the event of delays or extraordinary weather, could become overloaded.

A second element in designing the program is the amount of time the estimated capacity shortfall would exist. If the capacity shortfall requires many hours of interruption to manage properly, customers may not participate enough to provide the needed load relief. However, if the shortfall can be identified to a limited number of days and a limited number of peak load hours during those days, then a load curtailment program may provide the necessary load relief if needed, and typically in New England, heat waves are limited to just a few weeks.

The third component is to determine if the existing population of large accounts could provide the necessary load relief.

Finally, the fourth component is the willingness of customers to modify their electrical loads and to evaluate the amount of financial incentive required to induce this modification. According to a 2001 E-Source report 'Making Peak Load Management Work for the Mid-market Industrials, a payment of at least $0.50 per kWh appears to be the minimum value for successful projects.

<u>History of targeted demand response at the Company</u>

- In 2004 the Company undertook a targeted demand response program (filed with the RI PUC as the Summer Load Relief Program) in the Warwick/Cranston area. This program was initiated to provide area load relief in the event the Company's proposed new substation on Kilvert St., in Warwick, were to experience unexpected construction delays which may prevent it from coming on-line before the heat of the summer, and the need to serve the higher electrical loads that come with the heat.

  The Company visited 35 customers with demands over 200 kWs who had Company distribution service from either the Pontiac substation in Cranston or the Lincoln Ave. substation in Warwick. Twenty-three of these accounts were offered load shed audits to help them determine specifically how they could participate in any load shed request. This project was initiated due to potential construction delays for the new substation as outlined above. The substation was energized in mid-June, and by the end of June, the other substations (Pontiac and Lincoln Ave) had been off-loaded by approximately 20 MWs. Since no above-average loads were experienced in the early summer, the Company did not call any load shed events prior to the substation being energized. As of that date, the Company has only received 4 agreements back from customers willing to participate in the program. Many customers were interested in the program but were reluctant to sign an agreement to participate, even though no penalties existed for non-performance. The Company coordinated its promotion of the targeted demand response area with the ISO-NE's programs, in response to the increased number of price response events called by the ISO. The Company viewed the ISO programs as something all medium to large Commercial and Industrial customers should be interested in. The Company broadly marketed the ISO programs with this in mind, offering audits for customers enrolled in either the Company's demand response program or the ISO-NE programs. The audits provided customer education, efficiency project opportunities, as well as guidance for maximizing benefits from participation in the Company's and ISO-New England's demand response programs.

- In 2005, the Company identified the area that served the area fed by the L190 115 kV expansion project. This consisted of loads fed from the Ashaway, Hope Valley, Wakefield, Bonnet, Westerly, Kenyon, LaFayette, Wood River and Peacedale substations. This was an area in its service territory where there are a sufficient number of large customers who have the ability to shed load in a manner that could help the Company meet potential extreme peak loads or unexpected contingency events in the area prior to completion of the transmission upgrade or resulting from delays in the L190 project. Even though the amount of load relief needed was over 50 MWs if there was a failure of one of the 115 kV lines in place, a smaller program was begun with the understanding that, if needed, a significantly larger program might be built off the smaller one. The program was designed for retail delivery service customers in the area who had a minimum monthly billing demand of 200 kilowatts, and who could curtail load by at least 50 kilowatts on short notice.

  The Company paid participating customers capacity payments as well as energy payments based upon the amount of load curtailed in each hour of called interruptions. Capacity payments were $3.00 per kw-month (for three summer months) and energy payments were 50¢ per kWh curtailed. Performance was measured using the same methodology utilized by ISO-NE in their demand response programs. The payments were provided to customers in the form of a bill credit after the end of the season.

  Based on the results of NG-RI's sister company, NG-MA, in its Targeted Demand Response Program (also knows as the Brockton Pilot), NG-RI anticipated enrolling approximately forty percent (40%) of the eligible customers in the area that could shed 8% of their total load when called upon. In this selected area, there were 51 large customers that represent approximately 34,000 kW of load. Using the percentages above, the Company anticipated enrolling 20-25 customers, and targeting 2,000 to 2,700 kW's of load relief. Twenty-one customers were enrolled in the program for a total of 1.95 MWs. No calls were made for the summer of 2005 due to cooler than normal weather.

- In 2006 the Company made three calls for load shed in the area and saw peak load reductions ranging from a low of 1.5 MWs, to a high of 2.1 MWs. Twenty-one customers earned credits totaling over $32,000.
- No calls were made for the summer of 2007 for the same reasons as in 2005.
- In 2008, The L190 transmission line upgrade was energized, and should meet the needs of the area for a projected 10-year period based on the area's historical load growth. Therefore, targeted load relief in the area is no longer needed.

Demand response program specifics

Since 2002, the Company has offered qualifying customers the opportunity to participate in the ISO voluntary Real Time Price Response program as well as their Real Time Demand Response Program. Until 2007 the focus was on the voluntary price response, because there were not significant credits available from the demand response programs to enable customer participation until the transitional forward capacity market began in December 2006.

A key aspect of a planned demand response program is providing customers with a demand response audit that results in an action plan customers can execute that enables them to better manage and automate their load. The Company has offered only a limited number of demand response audits in Rhode Island since 2004 because only limited funding was available through the overall energy efficiency program offerings. We propose to dedicate additional funding for demand response audits in Rhode Island for use by any customer participating in either a Company or ISO-NE demand response program and/or taking advantage of hourly pricing through a third party supplier. In 2008 the proposal is to identify various demand response actions that may be undertaken by customers depending on the level of need and potential credits as well as the actions that customers can take to maximize the benefits from hourly pricing as provided by third party energy suppliers. The audits would identify specific load management strategies that may help customers reduce demand charges, identify additional energy efficiency and load automation opportunities, increase load factors, and maximize demand response program participation.

Another key aspect to successful demand response is providing information – such as the results of a load shed event – to customers about their energy consumption patterns. Consequently, the Company proposes to fund installation of advanced near real time metering technology for customers who have received load shed audit services and elect to enroll in the Company's distribution demand response program. These meters would assist customers in determining the impact of their actions on their load and assist the Company in assessing the actual demand reduction that is achieved by the customer. Near real time metering information may also supplement other energy efficiency activities at customer sites such as energy consumption analyses and commissioning. The Company would also explore ways to develop customer responsiveness to load and price signals through these meters and other sensing technologies, as well as through enhancements to the internet based Energy Profiler Online service available to large customers.

In addition, the Company will propose to offer financial incentives to encourage the installation costs for devices that can be used to control, monitor, and automate loads. These rebates would be specifically for control of hard wired devices (i.e. controllers on chillers, lighting, etc.) that could be remotely monitored and controlled to shed load upon request, either due to one of the Company's targeted demand response projects, in response to an ISO-NE load shed event, or as part of managing an hourly pricing option from a third party energy supplier. The intent is to assess the benefits and costs of such a demand reduction oriented control installation, and to begin developing cost effective use cases for load automation. The costs of the rebates also would be a part of the program costs recovered from customers in rates.

Table 1. Proposed DR budget for 2009-2011

	Year		
Program	2009	2010	2011
Number of proposed demand response audits	50	75	100
Estimated cost per audit	$4,000	$4,250	$4,500
Estimated annual audit costs	$200,000	$318,750	$450,000
Number of proposed demand response projects	20	40	60
Estimated rebate per project	$10,000	$15,000	$20,000
Estimated annual rebate costs	$200,000	$600,000	$1,200,000
Total proposed costs	**$400,000**	**$918,750**	**$1,650,000**

Target Market and Marketing Approach

Market segments that may be targeted with demand response services include:

- large customers on highly loaded distribution system components;
- small and medium sized customers with potential for direct load control located where past and anticipated load growth has the potential to outpace infrastructure improvements;
- customers who have enrolled in ISO-New England's demand response programs or who either are currently receiving hourly price signals or have an hourly pricing contract.

The primary population for audit services are customers who participate in ISO-NE Real time Demand Response Programs and the FCM they are transitioning to. Typical customer profiles include customers with newer buildings (office buildings, retail establishments, schools, institutional customers etc.), which currently have building management systems (BMS) to monitor life safety conditions (smoke, fire alarms), security, and HVAC systems. Buildings with modern building management systems are typically less than 25 years old. Using and/or modifying these systems to automate the control should have the potential to garner significant electrical savings, while also providing load control during peak hours of the year. Industrial process customers with potentially controllable or variable production loads are also possible candidates.

The Company's demand response program manager, in consultation with the Company's Account Executives, would market this initiative to customers on a one-to-one basis. Customers would be informed of the potential benefits to their companies, to the utility, and to the regional electricity market. The individual participating customers would not incur any cost for the basic load shed audit up to a cap to be established by the Company.

Target End Uses, Recommended Technologies, and Financial Incentives

The list of measures recommended for consideration by a customer may include some or all of the following:

- automating load shedding measures
  - building management system control changes, including temperature setbacks for HVAC systems;
  - integration of existing building management systems with emerging demand response dispatching systems;
  - lighting controls, either manually or through an EMS;
  - operation of emergency generation under extreme reliability emergencies;
  - integration of services provided through the Retro-Commissioning Initiative with demand response services
- load shift measures
  - scheduling of industrial processes, such as rearranging shift operations
- implementation of efficiency measures that offer options to cost-effectively reduce demand
  - lighting retrofits, including multi level or dimmable electronic ballasts for lighting;
  - cooling system upgrades, including chiller efficiency improvements and CO_2 sensors to regulate air distribution;
  - compressed air system modifications

Energy consumption and load can be controlled by building management systems through various strategies employing equipment such as dimmable electronic ballasts for lighting, temperature setbacks for HVAC systems and CO_2 sensors to regulate air distribution. Utilizing existing technology within the buildings to automate systems should provide ways for customers to shed load, and potentially allow the Company to control these loads. Open protocol systems are now becoming commonplace and can be integrated into existing systems to provide a much higher level of control.

Demand-reducing measures that also save energy may be run through the Custom Measure approach under Energy Initiative and Design 2000*plus* to determine cost-effectiveness and rebate eligibility under standard energy efficiency protocols. If a measure is not cost-effective, it would not be funded through the energy efficiency programs.

Combined measures that result in energy savings as well as creating ability for customers to reduce short-term demand may be evaluated based on retail bill savings as well as anticipated demand response payments with costs allocated in proportion.

Providing customers access to the payment streams from the ISO-NE demand response programs and FCM, and more importantly, the tools to allow participation, would provide added incentives for customers. An internet enabled gateway also has potential to provide real-time demand data allowing customers to experiment within their facility to modify their load curves and further reduce the overall electric bill. As more experience is gained, the benefit-cost analyses of demand response strategies would be further refined.

Delivery Mechanisms

Following the initial recruitment of customers by the program manager and Account Executives, several technical assistance (TA) contractors would be used to identify demand response options, prepare analyses and reports, and coordinate their implementation. Economies may be achieved if these demand-oriented studies are performed simultaneously with broader energy efficiency TA studies. As mentioned previously, there may be an opportunity to couple demand response audits with retro-commissioning studies.

Evaluation Overview

A process evaluation of the Demand Response program would be completed late in 2009 to determine the amount of automated load shed and the resulting costs to achieve the load shed.

4. Distributed/Targeted Resources in Relation to T&D investments

The company proposes the following pilot for the Aquidneck Island area in RI.

A recent electric distribution level study discussed a wide variety of loading issues on the sub-transmission and distribution systems serving the islands of southeastern Rhode Island. This includes Newport, Middletown, Portsmouth, Jamestown and Prudence Island. The recommended solution of adding a substation and three 13.8 KV feeders is currently on hold pending determination of a suitable location for the new substation. An alternate plan of rebuilding the 23KV loop in the Newport area may be the most viable solution for the near term (next decade).

We propose a pilot program to determine cost/benefit of ARTs that would need to focus on the summer peaks which contribute to the electric system loading, as well as winter peaks which contribute to gas pressure problems at peak.

Description of current issues with electric distribution and transmission

A study titled "Newport, RI Supply and Distribution Study" was published in May 2007 by the Company's Distribution System Planning group. The study examines all the loads served by the L14 and M13 lines that terminate at Dexter #36 substation in Portsmouth. The customers served are in the communities of Newport, Middletown, Portsmouth, Jamestown and Prudence Island.

A wide variety of loading issues currently exist and are expected to worsen during the study's 10-year span due to anticipated annual load growth rate of 1.6%. The issues involve thermal loading on substation transformers, sub-transmission systems and distribution feeders; ground fault circuit breaker duties; loading above ties; and load above risk. Several options for relief of most of these concerns were considered. Three options were rejected and one of two remaining options, involving installation of a new substation and three 13.8KV feeders, was selected. The search for a suitable site for the new substation has not yet borne fruit. If National Grid is unable to secure a suitable site for the new substation, the only real option left is to reinforce the existing 23KV sub-transmission system. The area has a peak load of 146 MWs. The work has been split into 2 phases described below.

Phase 1 is designed to meet the immediate needs for the summer of 2009. The Company plans to expand the 13 kV distribution system by converting some of the load currently served on the 4 kV system, build a new 4 kV feeder, and better balance the 4 kV loads served from the 23 kV supply circuits in the area. This work is expected to alleviate the most critical loading concerns on the 23kV supply and 4kV distribution system until the new substation is constructed. However, if one of the two 23 kV circuits at peak loading conditions feeding the W. Howard and Harrison substations in Newport, and the Eldred and Clark St substations on Jamestown Island, were to go out, this would result in un-served load until repairs are completed.

Phase 2 would be to construct a new substation in the City of Newport. Negotiations continue with the Navy on the use of some of their land for this substation. Additional conversion from 4 kV to 13 kV would be done as well, along with additional balancing of loads on the 23 kV supply circuits. This would depend on siting and building a new substation which would likely take 2-4 years.

Since phase 2 is some years away the use of ARTs in the greater Newport area to relieve peak loading conditions either to prevent the potential loss of one of two 23 kV circuits into the substations discussed above or to provide load relief in the event of the loss of a 23 kV circuit and to allow greater flexibility to restore load quicker, may prove beneficial for the period 2009-2011.

Description of customer base

In order to determine the menu of ARTs to be used in the area, the types and loads of different customer segments is needed. Just under 35,000 electric accounts exist for the communities in question. Figure 1 shows the breakdown by broad customer rate class:

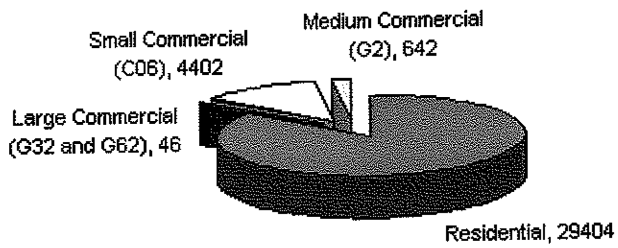

Figure 1 – Newport, Middleton, Portsmouth, Jamestown, Prudence Island customer base

The customer base is largely residential. There are two G62 customers and 44 G3 customers. The G62 customers are fed off of either 13.8 or 69 KV. A majority (32) of the G3 customers are fed via 4KV and all 32 are located in Newport.

Load profiles

An examination of the Company's loading data for the four 4 kV substations that supply downtown Newport and Jamestown shows that peak loads occur during summer heat waves. By comparing the plot of loads for July-August with the annual load duration curve, one can see the correlation, at least in 2007, of peak loads with the summer heat wave. The daily curve during heat waves shows an extended peak, which may be difficult to reduce without a good mix of ARTs. The two substations shown below, West Howard (peaks at 11 MVA) and Harrison (peaks at 6.4 MVA), largely feed the tourist area and Fifth Ward areas around Lower Thames. The loading curves from both show the number of hours load relief is needed. Peak loads for West Howard Sub occurred from 5:00 – 6:00 PM on August 3rd, 2007. For Harrison Sub, the peak occurred from 4:00 – 5:00 PM on August 2nd, 2007.

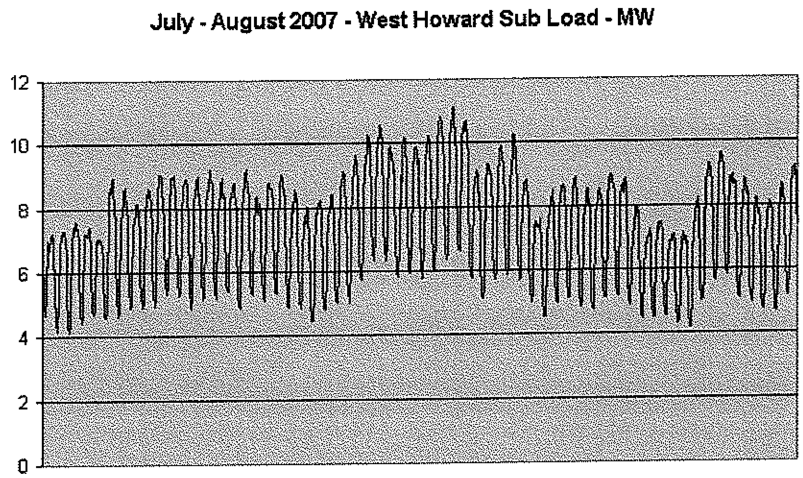

Figure 2 – W Howard loads 2007

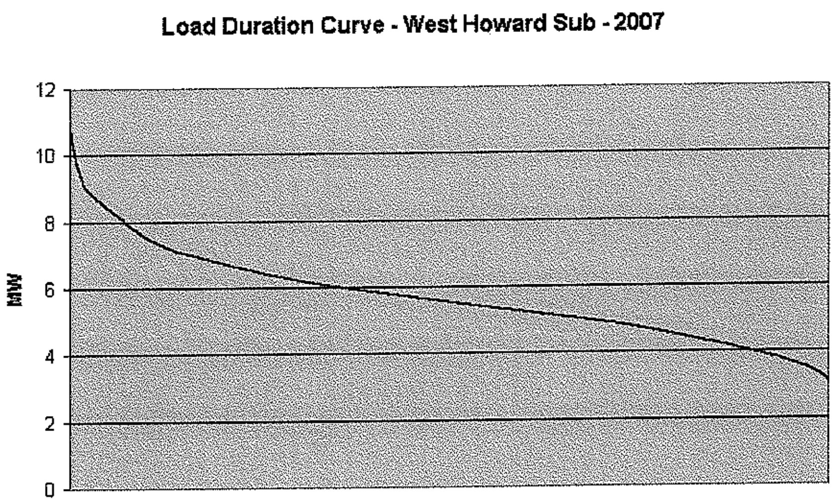

Figure 3 – W Howard load duration curve

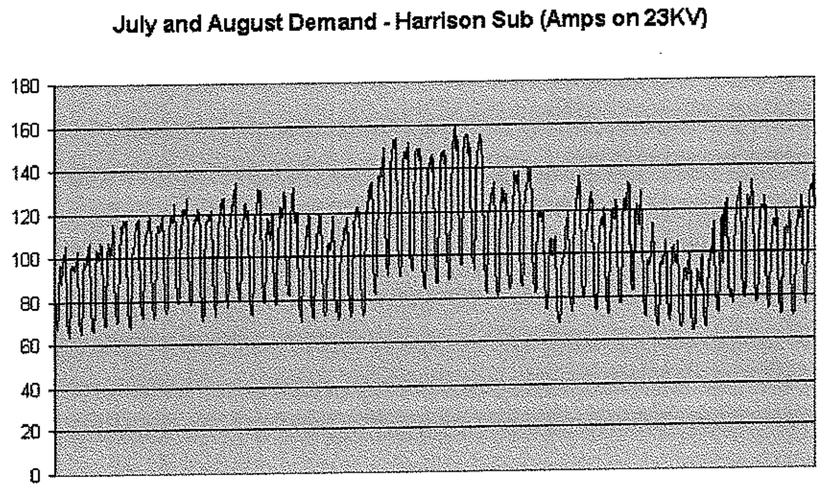

Figure 4 - Harrison substation loads 2007

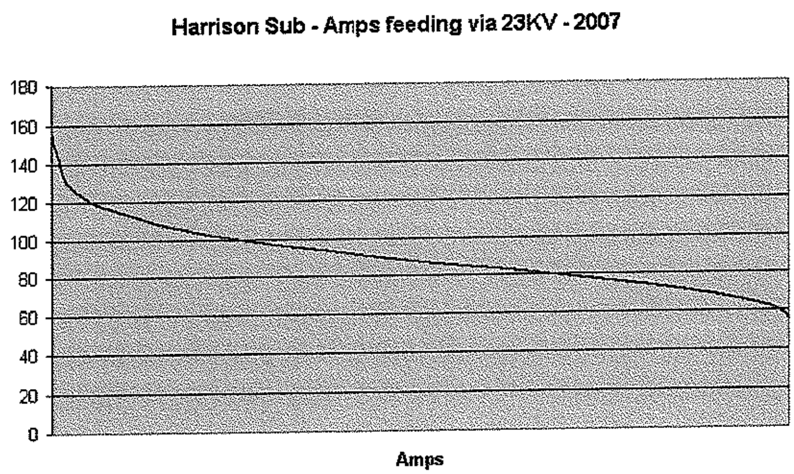

Figure 5 - Harrison Substation load duration curve

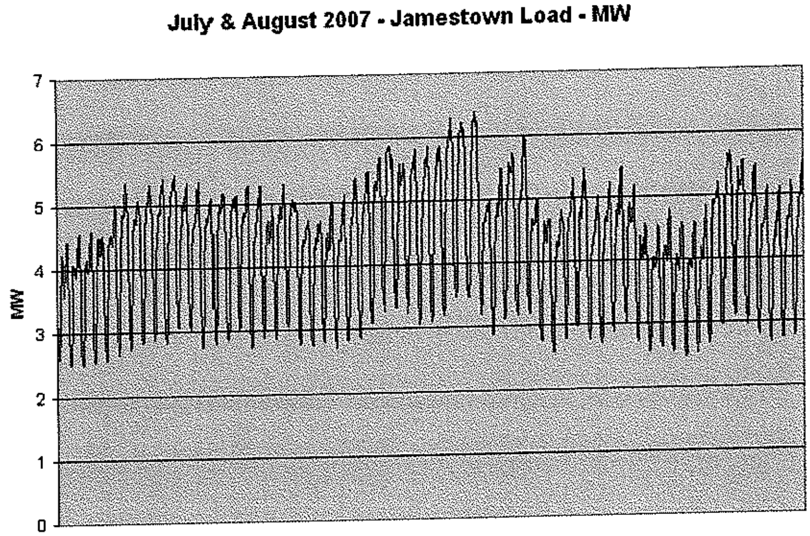

Figure 6 -July and August 2007 Demand - Jamestown Loads

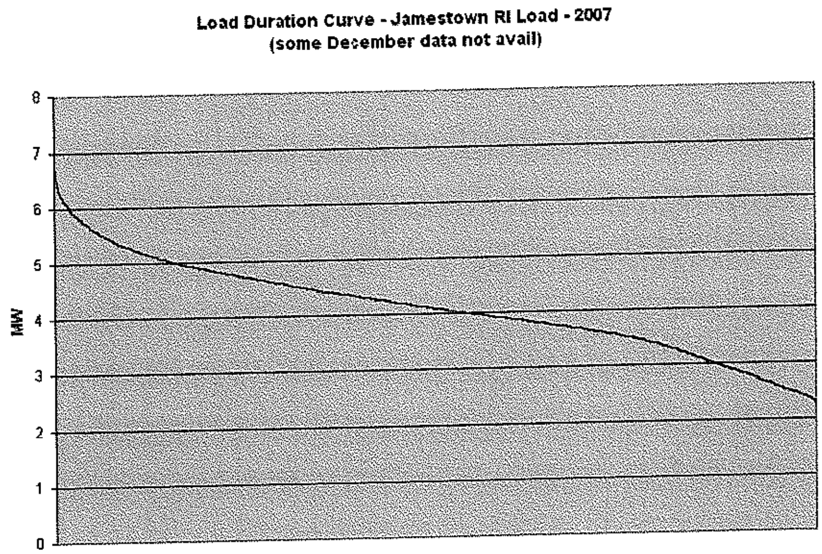

Figure 7 - Jamestown Loads Calendar Year 2007

Peak loads for Jamestown occurred from 5:00 – 6:00 PM on August 4th, 2007

Substation load by customer rate class

Figures 8 and 9 show the breakdown of peak by rate classes in each substation. Rate A16 is the residential portion, C06 and G02 are small C/I, and G32 is larger C/I.

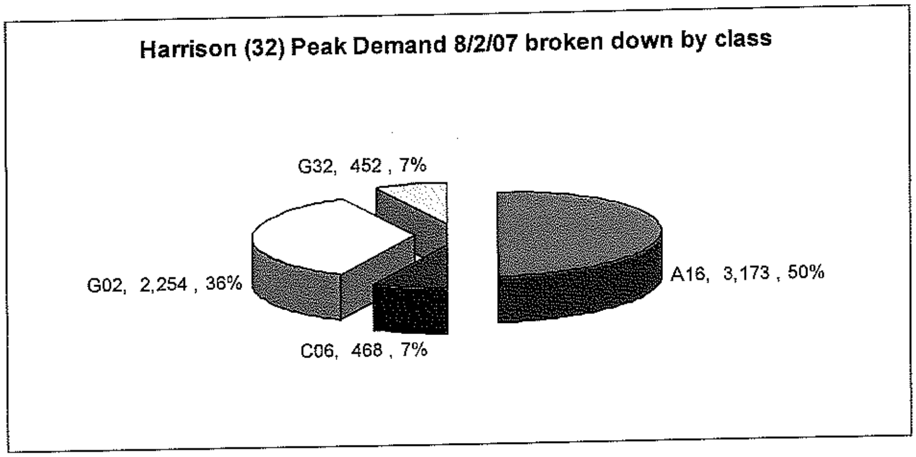

Figure 8 – Peak demand at Harrison Substation by rate class

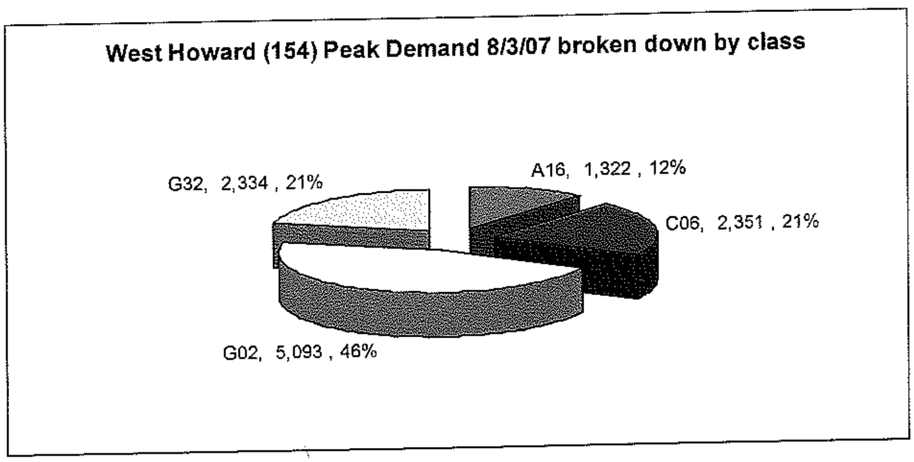

Figure 9 – Peak demand at W. Howard Substation by rate class

As indicated in the Phase 1 plans only, some of the 4 kV feeders out of these two substations are fed from the 23 kV circuit that needs load relief once the work scheduled for the summer of 2009 is completed. Table 2 below shows the customer breakdowns for the 4 kV feeders out of these substations as well as the two substations on Jamestown that ARTs would target.

Table 2. Customer Segmentation for Aquidneck Island

Substation/feeder	Rate class						
	A16 basic residential	A60 low income	C-06 small commercial	G-02 general C/I	G-32 C/I over 200 kWs	Total number of customers	Desired load relief
Harrison #32 - Newport							0.75 MW
32J2	813	19	33	20	1	886	
32J4	656	12	39	3	1	711	
total	1469	31	72	23	2	1597	
West Howard #154 - Newport							0.75 MW
154J2	93	0	116	17	1	227	
154J4	0	0	57	11	2	70	
154J6	206	3	56	0	0	265	
154J8	486	3	106	15	1	611	
total	785	6	335	43	4	1173	
Eldred #45 - Jamestown							0.75 MW
45J2	616	14	13	1	0	644	
45J4	493	2	33	4	0	532	
45J6	435	6	14	0	0	455	
Total	1544	22	60	5	0	1631	
Clark St #65 Jamestown							0.75 MW
65J2	661	16	130	24	0	831	
65J12	627	7	73	3	0	710	
Total	1288	23	203	27	0	1541	
overall totals	5086	82	670	98	6	5942	3 MW

<u>Specific ARTs suggested for use</u>

Since the loading issue is resolved with work in Phase 2, load relief of approximately 0.75 MW per 4 kV substation is desired. Within this group of customers, the following ARTs would be offered to residential and small commercial customers over the period 2009-2011:

1) Demand response
   a. HVAC and appliance direct load control (DLC) through the use of thermostat and/or smart plug load control to customers with broadband internet access in their homes and/or small businesses

i. The Company plans to determine if controlling thermostats during peak conditions on the gas distribution system would alleviate gas pressure issues during these peak hours.

ii. The Company sees some linkage between the DLC component of the pilot and the Energy Efficiency Procurement Plan and will explore funding some portion of the DLC in the pilot from energy efficiency funds.

b. Conduct demand response audits for customers

c. Evaluate an optional critical peak pricing program utilizing DLC hardware and hourly metering systems.

2) Renewables

a. Solar photo-voltaic panels

i. Target is to install 500 kWs

ii. Since the Company is in the process of a 25 to 50 MW solar RFP for its MA subsidiary, the cost is estimated to be $6/watt plus administration for a total of $3.5 million

b. Wind

i. Work with the municipalities to initiate a wind turbine studies that may be appropriate

ii. $100,000 proposed to be allocated

3) CHP

Due to a gas constraint in the same geographic area, further study is needed prior to offering a CHP or micro-CHP option.

Table 3 below shows the estimated cost and savings for the entire pilot program.

Table 3. Aquidneck Pilot Budget and Savings, 2009-2011

		Population	Penetration	kW per customer	Total kW	Cost per customer	Total Cost
Demand Response							
Residential DLC *		5168	20%	1	1033.6	$2,000	$2,067,200
Small Commercial DLC *		670	20%	5	670	$5,000	$670,000
Medium Commercial **		98	25%	15	367.5	$7,000	$171,500
Large Commercial **		6	50%	75	225	$25,000	$75,000
Demand Response Totals					**2296.1**		**$2,983,700**
Renewable Energy							
Solar PV		5942	2%	4.2	500	$25,200	$3,000,000
Wind		1	100%			$100,000	$100,000
Renewable Energy Total					**500**		**$3,100,000**
Grand Total					**2796.1**		**$6,083,700**

* the Company would offer enrolled customers an hourly pricing option. The Customer would receive the lower of the standard bill or a bill based on hourly pricing.

** the Company would consider the use of targeted demand response credits as used in the 2004 through 2007 projects: capacity payments of $3.00 per kW-month (for June, July and August) and energy payments of 50¢ per kWh curtailed.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:	STANDARDS FOR ENERGY EFFICIENCY AND CONSERVATION PROCUREMENT AND SYSTEM RELIABILITY	:	DOCKET NO. 3931

REPORT ON STANDARDS

I. Introduction

In 2006, the Rhode Island General Assembly passed legislation regarding least-cost procurement of energy by distribution utilities in Rhode Island. The legislation, codified as R.I. Gen. Laws § 39-1-27.7, requires the Public Utilities Commission ("Commission") to establish standards for system reliability and energy efficiency and conservation procurement. The standards are intended to guide the distribution utilities in developing a plan for system reliability and energy efficiency and conservation procurement on or before September 1, 2008 and triennially thereafter. R.I. Gen. Laws §39-1-27.7.

On February 29, 2008, the Energy Efficiency and Resource Management Council ("EERMC") filed proposed standards and recommendations as required by R.I. Gen. Laws §39-1-27.7(c)(1).[1] The proposed standards contained two sections: Energy Efficiency Procurement Standards that address the procurement of energy efficiency and conservation programs that are prudent and reliable when they are lower than supply

[1] Although the law specifies that the commissioner of the office of energy resources and the EERMC provide findings and recommendations to the Commission either jointly and/or separately, the Commission received only proposed standards from the EERMC. The Office of Energy Resources filed comments with the Commission subsequent to the filing of the proposed standards.

alternatives and System Reliability Procurement Standards that address the development and procurement of alternative power sources.[2]

The proposed Energy Efficiency Procurement Standards identify the plan filing dates and sets forth the Energy Efficiency Procurement Plan Components which include strategies and an efficiency performance incentive plan. These proposed standards also identify the Energy Efficiency Program Plan Components to include: program design, funding, program descriptions, monitoring and evaluation and reporting requirements. Finally, this section defines the role of EERMC as active in providing assistance to develop the program plan and ensuring that the state's ratepayers benefit from implementation of the plan. The proposed standards also discuss System Reliability Procurement and address distributed targeted resources, renewables, combined heat and power and demand response. Finally, the proposed standards address aligning utility incentives and reforming rates by proposing implementation of a decoupling mechanism[3], reviewing standby rates and streamlining interconnection standards.[4]

II. Notice and Hearing

The Commission opened a docket to address the proposed standards and to establish the final standards as required by law. The Commission issued a Notice of Public Hearing regarding the proposed standards. The notice specified that the Commission would consider the proposed standards and comments received in response to the proposed Standards.[5]

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[2] Exhibit 2, Proposed Standards and Cover Letter filed February 29, 2008.
[3] "Decoupling" is a ratemaking mechanism that disconnects the relationship between sales volume and profits. *See* Exhibit 4.
[4] *Id.*
[5] Exhibit 1, Notice of Hearing.

A number of interested persons filed Motions to Intervene with the Commission. They included EERMC, the Rhode Island Office of Energy Resources ("OER") Blue Water Wind, LLC, the Conservation Law Foundation, Environment Northeast and Cape Wind. National Grid ("NGrid") also filed a letter with the Commission indicating that it believed it was a necessary party to the docket and thus intervention was unnecessary. None of the Motions to Intervene were objected to within ten (10) days of filing as required by Rule 1.13(e) of the Commission's Rules of Practice and Procedure to cause the Commission to consider such motions and thus all were granted by operation of law.

Written comments were filed by all of the intervenor's except for the Conservation Law Foundation. Additionally, the Commission received written comments from the Division of Public Utilities and Carriers ("Division") and NGrid. All of the comments and reply comments were marked as full exhibits after no objection was raised by any of the parties as to their admissibility.[6]

NGrid provided comments agreeing with the proposed standards.[7] The Division also agreed with the standards as proposed with the exception of inclusion of decoupling language, noting that "decoupling issues are best addressed in more traditional ratemaking venues."[8] Bluewater Wind and Cape Wind agreed with the proposed standards but want large scale renewable projects to be included as part of the standards.[9] Additionally, Cape Wind recommended that long-term portfolio costs be included in the economic analysis and that the standards recognize environmental and economic

[6] Exhibits 3-13.
[7] Exhibit 3, Comments of National Grid filed April 23, 2008.
[8] Exhibit 4, Comments of the Division of Public Utilities and Carriers filed April 24, 2008.
[9] Exhibit 6, Comments of Blue Water Wind filed April 25, 2008; Exhibit 8, Comments of Cape Wind filed April 24, 2008.

development costs and benefits.[10] Environment Northeast also provided comments supporting the standards.[11] Again on May 12, 2008, Environment Northeast filed comments agreeing with the position of the division but stressing that "[e]nergy efficiency and decoupling are inextricably linked" and recommending that the Commission adopt the decoupling language proposed by EERMC.[12]

The Rhode Island OER also filed comments.[13] The detailed comments were identified by OER as being filed with "[t]he purpose of contribut[ing] to the discussion ultimately leading to the adoption of regulations. OER commented that EERMC's recommendations made a number of good proposals. They, however, challenged a number of sections of the proposed standards. OER challenged the funding sources from System Benefits Charge ("SBC"), Forward Capacity Market ("FCM") Revenues, proceeds from the sale of Regional Greenhouse Gas Initiative ("RGGI") allowances and funding from any federal or international cap and trade legislation or policy. Additionally, OER requested that the standards provide guidance as to how the utility should balance cost benefit and risk and reliability. OER's comments also included the statement that "[t]he Commission should not infer from OER's decision not to specifically address a particular point or language of EERMC's proposal in [the] comments that OER necessarily supports such point or language."

[10] Exhibit 8, Comments of Cape Wind filed April 24, 2008.
[11] Exhibit 7, Comments of Environment Northeast filed May 12, 2008.
[12] Exhibit 9, Comments of Environment Northeast in response to the Division's Comments filed May 12, 2008.
[13] The statute, R.I. Gen. Laws §39-1-27.7 requires the commissioner of the office of energy resources to file either separately or jointly with the EERMC findings and recommendations regarding system reliability and energy efficiency and conservation procurement. OER did not file findings and recommendations either separately or jointly with EERMC but filed detailed comments on the proposed standards filed by EERMC.

NGrid, Environment Northeast and NGrid, Environment Northeast and EERMC filed reply comments jointly. NGrid filed reply comments separately indicating that large scale wind resources may not become part of its portfolio unless they are the best, least-cost option. It indicated that wholesale power purchase plans should not be addressed in the Energy Efficiency and system Reliability Procurement.[14] Environment Northeast also filed reply comments which agreed with the comments of the Division but recommending that the decoupling language as proposed be adopted by the Commission.[15]

NGrid, Environment Northeast and EERMC ("Group") also filed joint reply comments which addressed all of the other parties' comments. Regarding the comments filed by Bluewater Wind and Cape Wind, the Group stated that NGrid's Supply Procurement Plan which will be filed by March 1, 2009 will include large scale wind resources.[16] Regarding the comments filed by the Division, the Group stressed that even though the design or rate adjustment mechanism of any decoupling must be approved by the Commission in another proceeding, the inclusion of the decoupling language in the standards is necessary for the EERMC and NGrid to begin working on properly aligning incentives and this will be important to the success of the Least Cost Procurement.[17]

The Group also filed reply comments to the comments submitted by OER. Regarding OER's comments about cross-subsidization, the Group responded that the principles in the proposed standards give sufficient guidance to a utility as it seeks to pursue all efficiency that is less costly than supply. OER further questioned whether the proposed standards allowed for individual programs not to pass the lower-cost test if the

[14] Exhibit 13, Reply Comments of National Grid filed May 9, 2008.
[15] Exhibit 9, Reply Comments of Environment Northeast filed May 12, 2008.
[16] Exhibit 11, Reply Comments of EERMC, Environment Northeast and NGrid to Comments of Bluewater Wind and Cape Wind filed May 13, 2008.
[17] Exhibit 10, Reply Comments of EERMC, Environment Northeast and NGrid to Comments of the Division filed May 13, 2008.

total of the programs passed the test. The Group responded that the language is clear that all programs are to pass the TRC cost effectiveness test. As for OER's recommendation that a downward "risk adjustment" factor be applied to program cost effectiveness measurement, the Group noted that it is only aware of a risk adjustment factor utilized in Vermont that raises the cost effectiveness estimates of efficiency programs as compared to supply alternatives in recognition of the risk reduction benefits. Additionally EERMC sees no need to change the current practice for program planning and establishment of savings targets and notes that OER's recommendation "would add bureaucratic complexity, discourage innovation, disregard the nature of efficiency resources, and fail to recognize the essential intelligence and flexibility required to move efficiency into the market place in a dynamic and effective manner."[18]

Lastly, the Group addressed OER's comments about the funding sources proposed by the standards. First the Group noted that the current practice of funding efficiency with the current demand side management ("DSM") charge of 2 mills should continue. It also pointed out that the EERMC recommendation reflects that the funding plan proposed identifies additional funding sources to be added to the DSM efficiency fund. Regarding the proceeds from the sale of RGGI allowances, the Group points out that EERMC's recommendation that the most cost effective use of these funds is energy efficiency. Finally, while acknowledging that there are no programs that currently exist regarding any federal or international cap and trade legislation or policy from which

[18] Exhibit 12, Reply Comments of EERMC, Environment Northeast and NGrid to Comments of OER filed May 13, 2008.

funds can be allocated to expand energy efficiency programs, the Commission should establish a policy that would facilitate the use of such funds should they be established.[19]

Prior to the start of the hearing, the public was afforded the opportunity to comment and the Commission received oral and written comment from People's Power and Light ("PP&L"). Those comments included a request to carefully examine revenue decoupling and the risks of such to consumers or a poorly designed or implemented revenue decoupling mechanism. PP&L also suggested that the Commission consider a percentage of income plan or something similar to ensure all consumers access to energy.

During the hearing, which was held on May 14, 2008, EERMC was asked whether they believed that the legislation or standards applied to the Pascoag Utility District ("Pascoag") or Block Island Power Company ("BIPCo") as the cover letter accompanying the standards referred to NGrid. Sam Krasnow who spoke on behalf of EERMC indicated that he did not believe that Pascoag or BIPCo was subject to the conditions of the legislation.[20]

During testimony regarding the proposed decoupling language, Mr. Krasnow proposed neutralizing the language and replacing the specific language proposed with language that allowed for mechanisms "such as decoupling."[21] Carol White of NGrid explained that the programs are all part of the same package and that the current programs will be part of the least cost procurement when questions were posed regarding the funding of the programs and whether that funding would be competing with funds for existing programs.[22] She noted that NGrid is looking to build off the current programs

[19] *Id.*
[20] Transcript ("T.") of May 14, 2008 hearing at 42.
[21] *Id.* at 46-50.
[22] *Id.* at 58-59.

and that there will be an effect on customer bills for supporting these efforts.[23] She also pointed out that the per kilowatt charge may be a little higher but the intent is to eventually see lower overall bills for customers.[24]

When questioned at the hearing about the meaning of the language that OER had provided in its comments indicating that its lack of objection to a particular section did not imply that it supported such section, OER was unable to respond.[25] The Commission directed OER to file with the Commission, in writing, a list of any sections of the proposed standards that it objected to and the reason for such objection because of the comment provided to the Commission that just because it didn't object to a section in the standards should not be inferred as support of the section.[26]

After the hearing, the Commission received further comment. On May 21, 2008, Bluewater Wind, Cape Wind and NGrid filed joint comments noting that whether Least Cost Procurement included renewable supply sources was not considered at the time of the drafting of the proposed comments. These parties' joint comments requested the addition of language that would note the need to consider whether renewable supply sources should be included in Least Cost Procurement and report such to the Commission simultaneously with the November 1, 2008 filing. The joint comments also recommended removing the reference to small or medium renewable energy supply noting that these references assume that only small and medium renewable energy supply can provide system reliability benefits.

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[23] *Id.* at 59.
[24] *Id.* at 60.
[25] *Id.* at 51-54.
[26] *Id.* at 63.

On May 19, 2008, the Commission received extensive comments from OER, most of which were not substantive and were not discussed either prior to or at the hearing where the other parties had the opportunity to provide testimony or explanation. For example, in OER's original comments filed on April 23, it supported EERMC's use of the TRC test. In its supplemental comments, OER changed this position, requesting the Commission to order further proceedings and have the test be determined at some later date. It also recommended deleting the sections of the proposed standards that allowed for decoupling and incentives noting that it was more appropriate to consider them in other proceedings.

NGrid, EERMC, ENE and the CLF filed reply comments to OER's comments. These parties requested that the Commission disregard these comments as violating the Commission's record request because they raise new clarifying arguments and new issues and subjects that it does not appear to oppose. These parties also provided detailed explanation as to why each of OER's points should be substantively rejected. Additionally, in these comments, NGrid, EERMC, ENE and the CLF stated that a "solution [was] worked about by the parties and Commission staff through a discussion at the May 14 hearing" regarding the issues surrounding decoupling. That is factually inaccurate. The parties were questioned by staff regarding decoupling and then EERMC proposed alternative language. That language was never agreed to by Commission staff as such an agreement would be improper.

III. Findings

On June 12, 2008, the Commission considered the proposed standards during an open meeting. Currently Pascoag provides its portfolio through its standard offer filings.

While the Commission cannot exempt Pascoag from the legislation, it will consider the portfolio submitted with its standard offer filing to be sufficient to comply with the requirements of the statute. Pascoag will continue to submit its portfolio through that process and verify to the Commission that it is procuring all energy efficiency that is less costly than supply.

The Commission also considered a number of the proposals made by the parties to modify the originally proposed standards. With regard to the proposal of NGrid, Bluewater Wind and Cape Wind to add language to consider whether renewable supply sources should be included in Least Cost Procurement and report such to the Commission simultaneously with the November 1, 2008 filing, the Commission believes that in light of the uncertainty surrounding state policy and the law regarding renewable energy supply, such language is necessary to insure that the standards include all required supply sources. Therefore, Section 1.1 C shall be added to the proposed standards. The Commission also notes the need for neutrality as to the size of renewables recognizing that system reliability enhancements can be achieved at both the distribution level and the transmission level. As such, the Commission approves the request to eliminate the references to small and medium renewable energy supply in Sections 2.2 A (1) and A (2).

In light of the fact that the Commission has a pending docket in which a party is requesting approval for a decoupling mechanism, the Commission does not believe it is appropriate at this time to include any references to decoupling in these standards. Prior to the Commission deciding on the issue of decoupling, the Commission will conduct an extensive investigation into this type of mechanism to ensure that the interests of all parties to a proceeding are evaluated and protected. Therefore, Sections 1.2B and 3.1

shall be eliminated from the proposed standards. As the Commission has previously addressed NGrid's Interconnection Standards in Docket No. 3904, Section 3.3 shall be eliminated. The Commission also believes that the proposed language in Chapter 2 prior to Section 2.1, Section 2.2(c) and Section 2.3(d) is unnecessary as it imposes no obligation on any party and therefore shall be eliminated. With exception to the above stated revisions, the remaining proposals shall be adopted as proposed.[27] The standards are attached hereto as Appendix A.

Accordingly, it is hereby

(19344) ORDERED:

1. The Proposed Standards filed by EERMC on February 29, 2008 shall be adopted by the Commission with the revisions noted above.

EFFECTIVE AT WARWICK, RHODE ISLAND ON JUNE 12, 2008 PURSUANT TO AN OPEN MEETING DECISION ON JUNE 12, 2008. REPORT ISSUED ON JULY 18, 2008.

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman

Robert B. Holbrook, Commissioner

Mary E. Bray, Commissioner

[27] For ease of reading some of the proposed numbering has been changed.

Appendix A

STANDARDS FOR ENERGY EFFICIENCY AND CONSERVATION PROCURMENT AND SYSTEM RELIABILITY

CHAPTER 1 – Energy Efficiency Procurement

Section 1.1 Plan Filing Dates

A. The Utility Energy Efficiency Procurement Plan ("The EE Procurement Plan") submitted on September 1, 2008 and triennially thereafter on September 1, shall propose overall budgets and efficiency targets for the three years of implementation beginning with January 1 of the following year.

B. The Utility shall prepare and file a supplemental filing on November 1, 2008 and annually thereafter on November 1, containing details of implementation plans by program for the next program year ("The EE Program Plan"). The November 1 filings shall also provide for adjustment, as necessary, to the remaining years of the EE Procurement Plan based on experience, ramp-up, and increased assessment of the resource levels available.

C. Simultaneously with the November 1, 2008 filing the Council and the Utility shall report to the Commission regarding the question of whether supply-side sources, in addition to the demand-side source addressed in this version of the standards, should be incorporated into future versions of the standards and the Least Cost Procurement Plan. In preparing this report, the Council shall solicit comment and information from all parties to Docket No. 3931, and any others as the Council may determine. In adopting these standards prior to receiving such a report, the Commission reserves the right to order revisions to the standards, and the Procurement Plan, prior to the next September 1, 2011 filing date.

Section 1.2 EE Procurement Plan Components

A. The EE Procurement Plan shall identify the strategies and an approach to planning and implementation of programs that will secure all cost-effective energy efficiency resources that are lower cost than supply and are prudent and reliable.

1. Strategies and approaches to planning.

   a. The Utility shall use the Council's Opportunity Report as issued on July 15, 2008 (and as it may be subsequently supplemented) as one resource among others in developing its EE Procurement Plan[28]. The Utility may include in its Plans an outline of proposed strategies to supplement and build upon the initial Opportunity Report.

b. The EE Procurement Plan shall describe the recent energy efficiency programs offered by the Utility and highlight how the EE Procurement Plan supplements and expands upon these offerings, including but not limited to new measures, implementation strategies, new strategies to make capital available to effectively overcome market barriers, and new programs as appropriate.

c. The EE Procurement Plan shall include a section describing a proposal to investigate new strategies to make available the capital needed to implement projects in addition to the incentives provided. Such proposed strategies shall move beyond traditional financing strategies and shall include new capital availability strategies that effectively overcome market barriers in each market segment in which it is feasible to do so.

d. The EE Procurement Plan shall address how the utility plans to integrate gas and electric energy efficiency programs to optimize customer energy efficiency

2. Cost-effectiveness

a. The Utility shall assess measure, program and portfolio cost-effectiveness according to the Total Resource Cost test ("TRC")[29]. The Utility shall, after consultation with the Council, propose the specific benefits and costs to be reported and factors to be included in the Rhode Island TRC test.

b. That test shall include the costs of CO2 mitigation as they are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative. They shall include any other costs associated with greenhouse gas reduction that are actually being imposed on energy generation and can be identified and quantified.

c. The utility shall provide a discussion of the carbon impacts efficiency and reliability investment plans will create.

3. Prudency and Reliability

a. In the initial three-year EE Procurement Plan, a ramp-up to achieve all cost-effective efficiency lower cost than supply shall be proposed by the Utility that is both aggressive in securing energy,

[28] The Opportunity Report is essential because it is required by law, and because it provides part of the analysis upon which the PUC will base its decisions as to the level of investment required to acquire all cost-effective efficiency that is lower cost than supply.

[29] Since the focus of the Rhode Island legislation is on securing customer benefits, not just Utility benefits from energy efficiency procurement, the TRC test is recommended.

capacity, and system cost savings and is also designed to ensure the programs will be delivered successfully and cost-effectively over the long term[30]. The proposed ramp-up will appropriately balance the significant cost saving efficiency investment opportunity that is identified and the near-term capacity and staffing issues within the utility and vendor community with an emphasis on ensuring an aggressive and sustainable ramp-up of program investments over time.

b. EE Procurement Plan efficiency investments shall be made on behalf of all customers. This will ensure consistency with existing program structure under which all customers pay for and benefit from today's efficiency programs.

c. The EE Procurement Plan should describe how it interacts with the System Reliability Procurement Plan.

4. Funding Plan and Initial Goals

a. The Utility shall develop a funding plan based on the following sources to meet the budget requirement of the EE Procurement Plan. The Utility shall utilize as necessary to fulfill the statutory mandate, the five following sources of funding for the efficiency program investments among others:

i. the existing System Benefits Charge ("SBC");

ii. forward capacity market ("FCM") revenues should be re-invested to help cover program costs.

iii. auction of Regional Greenhouse Gas Initiative (RGGI) allowances pursuant to § 23-82.6 of the General Laws which states allocation of RGGI proceeds shall be for that which "best achieves the purposes of the law, namely, lowering carbon emissions and minimizing cost to customers over the long term";

iv. funds from any federal or international climate or cap and trade legislation or policy including but not limited to revenue or allowances allocated to expand energy efficiency programs;

v. distribution rates, which is a funding mechanism to be relied upon after the other sources to ensure the legislative mandate to

[30] The Utility may propose a study or studies to investigate and document current energy efficiency program infrastructure in Rhode Island; to assess the ability of the infrastructure to meet increased demand for energy efficiency services; and to make recommendations for increasing capacity if needed. Any such report should address: staffing levels and ability to expand staffing; training and experience of staff; current workloads; interest in working with utility program sponsors; statewide coverage of services; and other relevant factors. Where appropriate, the Utility may partner with research efforts of this sort that are regional in nature or in other jurisdictions, so long as they provide pertinent information for building the Rhode Island infrastructure. The costs of these plans and the actions to implement them may be included as program costs.

procure all cost effective efficiency that is lower cost than supply is met.

b. The Utility shall include a preliminary budget for the EE Procurement Plan covering the three-year period that identifies the projected costs, benefits, and initial energy saving goals of the portfolio for each year. The budget shall identify at the portfolio level, the projected cost of efficiency resources in cents/ lifetime kWh. The preliminary budget and initial energy saving goals may be updated in the Utility's EE Program Plan.

B. Efficiency Performance Incentive Plan

1. Utility shall have an opportunity to earn a shareholder incentive that is dependent on its performance in implementing the approved EE Procurement Plan

   a. The Utility, in consultation with the Council will propose in its EE Procurement Plan, an incentive proposal that is designed to promote superior Utility performance in cost-effectively and efficiently securing for customers all efficiency resources lower cost than supply.

   b. The Performance Incentive should be structured to reward program performance that makes significant progress in securing all cost-effective efficiency resources that are lower cost than supply while at the same time ensuring that those resources are secured as efficiently as possible.

   c. The Utility incentive model currently in place in RI should be reviewed by the Utility and the Council. The Utility and Council shall also review incentive programs and designs in other jurisdiction including those with penalties and increasing levels of incentives based on higher levels of performance.

   d. The Incentive may provide incentives for other objectives that are consistent with the goals including but not limited to comprehensiveness, customer equity, increased customer access to capital, and market transformation.

   e. The incentive should be sufficient to provide a high level of motivation for excellent Utility performance, but modest enough to ensure that customers receive most of the benefit form EEP implementation.

Section 1.3 EE Program Plan Components

A. Principles of Program Design

1. The EE Program Plan shall identify the specific energy efficiency programs proposed for implementation by the Utility, pursuant to the EE Procurement Plan.

2. The Utility should consistently design programs and strategies to ensure that all customers have an opportunity to benefit comprehensively, where appropriate, from expanded investments in this low-cost resource and the programs should be designed and implemented in a coordinated fashion by the utility, in active and ongoing consultation with the Council.

3. The Utility shall propose a portfolio of programs in the EE Program Plan that is cost-effective. Any program with a benefit cost ratio greater than 1.0 (i.e., where benefits are greater than costs), should be considered cost-effective. While all programs should be cost-effective, the portfolio must also be determined to be cost-effective.

4. The Utility shall be allowed to direct a portion of proposed funding to conduct research and development and pilot program initiatives. These efforts will not be subject to cost-effectiveness considerations. However, the costs of these initiatives shall be included in the assessment of portfolio level cost-effectiveness.

5. All efforts to ramp-up program capability as identified in Section 1.2 A(3)(a) shall be done in a manner that ensures quality delivery and is economical and efficient. The utility shall include wherever possible and practical partnerships with existing educational and job training entities.

6. The portfolio of programs proposed by the Utility should be designed to ensure that different sectors and all customers get opportunities to secure efficiency resources lower cost than the cost of supply.

7. While it is anticipated that rough parity among sectors can be maintained, as the limits of what is cost-effective are identified, there may be more efficiency opportunities identified in one sector than another. The Utility should design programs to capture all resources that are cost-effective and lower cost than supply. The Utility should consult with the Council to address ongoing issues of Parity

8. The Utility shall explore as part of its plan, new strategies to make available the capital needed to effectively overcome market barriers and implement projects that moves beyond traditional financing strategies.

B. Final Funding Plan and Budget Amounts, Cost-Effectiveness and Goals

1. The Utility shall include a detailed budget for the EE Program Plan covering the annual period beginning the following January 1, that identifies the projected costs, benefits, and energy saving goals of the portfolio and of each program. The budget shall identify at the portfolio level, the projected cost of efficiency resources in cents/ lifetime kWh.

2. The EE Program plans filed November 1, will reflect program ramp-up experience and anticipated changes, shifts in customer demand, changing market costs, and other factors, as noted in Section 1 above. The annual detailed budget update shall include the projected costs, benefits, and energy saving goals of each program as well as the cost of efficiency resources in cents/ lifetime kWh.

3. The Utility, in consultation with the Council may propose specific non-energy benefits (NEBs) in its Residential Low Income program cost-effectiveness analysis in addition to the benefits included in the TRC test for all other programs.

4. The EE Program Plan shall identify the energy cost savings that RI ratepayers will realize through its implementation.

5. In order to assess the potential effect of greenhouse gas reduction costs, the Utility, upon consultation with the Council, shall conduct and report in the EE Procurement Plan filing a sensitivity analysis of the proposed portfolio of programs that includes a "potential" cost for CO2 mitigation that is agreed upon among the parties.

C. Program Descriptions

1. Utility program development shall proceed by building upon what has been learned to date in utility program experience, systematically identifying new opportunities and pursuing comprehensiveness of measure implementation as appropriate and feasible.

2. The Utility shall, as part of its EE Program Plan, describe each program, how it will be implemented, and the total costs and benefits associated with the efficiency investments

3. The Utility plan shall describe in each appropriate program section a plan to devise new strategies to make available the capital needed in addition to the incentives provided to implement measures.

4. In addition to these basic requirements, the plan shall address, where appropriate, the following elements:

   a. Comprehensiveness of opportunities addressed at customer facilities

b. Integration of electric and natural gas energy efficiency implementation and delivery (while still tracking the cost-effectiveness of programs by fuel).

c. Integration of energy efficiency programs with renewables and other system reliability procurement plan elements

d. Promotion of the effectiveness and efficiency levels of Codes and standards and other market transforming strategies. If the utility takes a proactive role in researching, developing and implementing such strategies, it may, after consultation with the Council, propose a mechanism to claim credit for a portion of the resulting savings.

e. Implementation, where cost-effective, of demand response measures or programs that are integrated into the electric and natural gas efficiency program offerings. Such measures/programs will be designed to supplement cost-effective procurement of long-term energy and capacity savings from efficiency measures.

D. Monitoring & Evaluation (M&E) Plan

1. The Utility shall, after consultation with the Council, include a Monitoring and Evaluation ("M & E") component in its EE Program Plan.

2. This M & E component shall cover the three years of the Plan, with a focus on the first year, and address at least the following:

   a. a component that addresses savings verification including, where appropriate, analysis of customer usage;

   b. a component that will address issues of ongoing program design and effectiveness;

   c. any other issues, for example, efforts related to market assessment and methodologies to claim savings from market effects, among others;

   d. a discussion of Regional and other cooperative M & E efforts the Utility is participating in or plans to participate in.

3. The Utility shall include in its M & E component any changes it proposes to the frequency and level of detail of utility program plan filing and subsequent reporting of results.

E. Reporting Requirements

1. The Utility, in consultation with the Council, will propose the content to be reported and a reporting format that is designed to communicate clearly and effectively the benefits of the efforts planned and implemented, with particular focus on energy cost savings, to secure all EE resources that are lower cost than supply.

Section 1.4 Role of the Council

A. The Council shall take a leadership role in ensuring that Rhode Island ratepayers get excellent value from the EE Procurement Plan being implemented on their behalf. The Council shall do this by collaborating closely with the Utility on design and implementation of the Monitoring and Evaluation efforts presented by the Utility under the terms of Section 1.3 D, and if necessary, provide recommendations for modification that will strengthen the assessment of utility programs.

B. As part of the Council's April 15 annual report required by 42-140.1-5 the Council shall report on program performance and whether program costs are justified, given the intent of the enabling legislation. The Council shall also report on the effectiveness of any performance incentive approved by the PUC in achieving the objectives of efficient and cost-effective procurement of all efficiency resources lower cost than supply and the level of its success in mitigating the cost and variability of electric service by reducing customer usage.

C. In addition to the other roles for the Council indicated in this filing, the Utility shall seek ongoing input from, and collaboration with the Council on development of the EE Procurement and Program Plans, and on development of the annual update to the Plan.

D. The Utility and the Council shall report to the PUC a process for Council input and review of its 2008 EE Procurement Plan and EE Program Plan by July 15, 2008 and triennially thereafter.

E. The Council shall vote whether to endorse the EE Procurement Plan by August 15, 2008 and triennially thereafter. If the Council does not endorse the Plan then the Council shall document the reasons and submit comments on the Plan to the PUC for their consideration in final review of the Plan.

F. The Utility shall, in consultation with the Council, propose a process for Council input and review of its EE Procurement Plan and EE Program Plan. This process is intended to build on the mutual expertise and interests of the Council and the Utility, as well as meet the oversight responsibilities of the Council.

G. The Utility shall submit a draft annual EE Program Plan to the Council for its review and comment annually by October 1.

H. The Council shall vote whether to endorse the annual EE Program Plan by October 15, annually. If the Council does not endorse the annual EE Program Plan, the Council shall document its reasons and submit comments on the Plan to the PUC for its consideration in final review of the Plan.

CHAPTER 2 – System Reliability Procurement

Section 2.1 Distributed/Targeted Resources in Relation to T&D Investments

A. The Utility shall propose pilot distribution and, if appropriate, transmission projects in their first system reliability procurement plan for which they will examine alternative resource strategies as alternatives or enhancements to the distribution or transmission upgrade. These pilot projects should be used to inform or revise the system reliability procurement process in subsequent plans.

B. Alternative Resource Technologies (ART) shall include but not be limited to:

1. Distributed generation generally
2. Combined heat and power
3. Renewables (predominantly wind and solar, but not constrained)
4. Demand response
5. Peak demand and geographically focused energy efficiency programs
6. In order to meet the statute's environmental goals, unless a compelling showing to the contrary, technologies selected or supported should:
    a. achieve a CO_2 emissions rate equal to or better than the ISO New England marginal emissions rate on an output basis (thermal and electric) – current rate ~1,100 lbs/MWh; and
    b. utilize best available control technology for NOx emissions

C. For each pilot the utility should identify an evaluation process that allows for input from the Council and other stakeholders and includes elements such as the following:

1. Identification and description of the T&D investment
2. Description of the need, requirements, and drivers such as demand growth (load curve and timing issues)
3. Description of the business as usual upgrade in terms of technology, costs (capital and O&M), and schedule for the upgrade
4. Identification of the level of peak demand savings required to avoid the need for the upgrade
5. Development of ART alternative investment scenario(s)
    a. Specific ART characteristics
    b. Development of an implementation plan, including ownership and contracting considerations or options
    c. Development of a detailed cost estimate (capital and O&M) and implementation schedule
6. Reporting and recommendations

a. Compare the investment options from a cost perspective – cost assessed on a net-present-value basis to the state's ratepayers (common assumptions across scenarios)

b. Include a summary of environmental impacts and a discussion of any co-benefits such as benefits to local businesses or industry

c. Recommend preferred solutions

D. The utility pilot program(s) should be reviewed and approved by the PUC as part of the System Reliability Procurement Plan submitted on September 1.

Section 2.2 Renewables

A. The utility shall consider opportunities to integrate renewable energy resources with measurable benefits into the system reliability plan and in a coordinated fashion with the implementation of efficiency procurement. Activities may include but not be limited to:

1. Renewable energy projects that compliment the distribution and transmission pilot projects or provide other system benefits;
2. Distributed renewable energy projects such as photovoltaics wind or solar thermal; and
3. Where appropriate, the Utility should coordinate its programs with the renewable energy fund.

B. The utility plan shall document current activities and commitments to increase renewable energy production and contracting and how those activities affect costs, benefits, price stability, fuel diversity, and environmental goals.

Section 2.3 Combined Heat and Power

A. The electric and natural gas efficiency programs should support and expand programs for CHP applications that are cost-effective, deliver net reductions in energy consumption, and provide environmental benefits.

B. The utility plan shall include discussion of CHP potential in the state based on the Opportunity Report and should set targets or goals for CHP penetration and if necessary propose new programs to support the development of CHP. The plan should describe how those activities affect costs, benefits, price stability, fuel diversity, and environmental goals.

C. CHP programs or projects supported by the Utilities should be sited at facilities with adequate thermal loads to ensure high levels of efficiency on an annual basis

Section 2.4 Demand Response

A. The Utility shall examine and implement where cost-effective, demand response measures or programs in coordination with the electric and natural gas efficiency program offerings. Such measures and programs will be designed to supplement cost-effective procurement of long-term energy and capacity savings from efficiency measures.

B. The Demand and capacity value of CHP and other distributed generation strategies shall be identified and quantified.

CHAPTER 3: Aligning Utility Incentives & Reforming Rates

Section 3.1 Review of Standby Rates

A. In order to facilitate increased fuel diversity and increased development of distributed resources in the state, standby rates for customers with on-site generation should be re-examined and adjusted if appropriate.

B. The Utility Reliability Procurement Plan should include a discussion of this issue.

Attachment B

Attachment B
Rhode Island Energy Efficiency Procurement Plan 2009-2011
Funding Plan

		2008 Plan	2009	2010	2011	3 year total
PART A: TOTAL FUNDING AND GOALS						
1)	Projected kWh Sales:	7,913,782,120	7,976,912,000	8,112,974,000	8,226,670,000	
2)	DSM Revenue per kWh	$0.002	$0.002	$0.002	$0.002	
3)	**Projected DSM Revenues from DSM Charge = (1) x (2)**	**$15,827,500**	**$15,953,824**	**$16,225,948**	**$16,453,340**	**$48,633,112**
	Other Sources of DSM Funding					
4a)	Projected DSM Fund Balance Interest	$390,800	$548,000	$665,900	$781,200	
4b)	Projected Co-Payments by Customers received in Pgm Year	$831,000	$1,165,400	$1,415,900	$1,661,100	
4c)	Projected Commitments from prior year	$4,337,200	$4,500,000	$6,310,700	$7,667,300	
4d)	Projected Entering Fund Balance:	-$1,288,600	$0	$0	$0	
4e)	Projected Capacity (Transition and FCM) Payments from ISO-NE:	$917,500	$1,082,700	$1,526,000	$1,909,400	
4)	**Subtotal Other Sources of DSM Funding**	**$5,187,900**	**$7,296,100**	**$9,918,500**	**$12,019,000**	**$29,233,600**
5)	**Projected Funding Available from Traditional Sources = (3) + (4)**	**$21,015,400**	**$23,249,924**	**$26,144,448**	**$28,472,340**	**$77,866,712**
6)	**Program Implementation + Evaluation Expenses to Achieve Goal**	**$14,861,355**	**$24,430,307**	**$34,738,972**	**$43,296,300**	**$102,465,578**
7a)	Co-Payments Projected to be received from Pgm Year Installations	$1,006,205	$1,253,000	$1,503,500	$1,661,100	
7b)	Estimated Commitments to Future Years	$4,500,000	$6,310,700	$7,667,300	$8,995,200	
7c)	Target Incentive	$647,700	$1,064,749	$1,518,090	$1,890,558	
7)	**Additions to Implementation + Evaluation Expenses**	**$6,153,905**	**$8,628,449**	**$10,688,890**	**$12,546,858**	
8)	**Total Funding Required = (6) + (7)**	**$21,015,260**	**$33,058,755**	**$45,427,862**	**$55,843,158**	**$134,329,775**

Attachment B

Rhode Island Energy Efficiency Procurement Plan 2009-2011
Funding Plan

		2008 Plan	2009	2010	2011	3 year total
PART B: POTENTIAL INCREMENTAL FUNDING NEEDED						
	Assumes no RGGI Proceeds					
9)	**Projected Funding Available = (5)**	**$21,015,400**	**$23,249,924**	**$26,144,448**	**$28,472,340**	**$77,866,712**
10)	Projected RGGI Proceeds		$0	$0	$0	
11)	Funding w/RGGI = (9) + (10)		$23,249,924	$26,144,448	$28,472,340	
12)	**Incremental funding needed from additional source (8) - (11)**		**$9,808,831**	**$19,283,414**	**$27,370,818**	
13)	**Incremental funding needed per kWh = (12)/ (1)**		**$0.0012**	**$0.0024**	**$0.0033**	
14)	Total DSM Charge Funding per kWh = (12) + (13)		$0.0032	$0.0044	$0.0053	
PART C: GOALS AND COST/LIFETIME kWh						
15)	**Program Expansion, Units savings relative to 2008**	100%	140%	170%	200%	
	Goal, Annual MWh (adj. for FR and Spillover)	54,268	74,387	88,546	102,566	**265,499**
	Goal, Annual Peak kW Savings (adj for FR and Spillover)	9,154	12,555	15,154	17,815	**45,524**
	Goal, Lifetime MWh (adj for FR and Spillover)	636,784	893,011	1,084,987	1,272,891	**3,250,888**
	Net benefits	$60,989,400	$78,278,112	$93,457,974	$109,866,367	**$281,602,453**
	Cost/lifetime kWh (incl. customer costs)	$0.032	$0.039	$0.044	$0.047	

Line Notes:

1 Sales from Company sales forecast (March 08) and includes Streetlights.
4a Fund balance interest projections assume that increased collection of funds will cause more money to flow through the DSM fund, creating more interest.
Projection assumes same interest rate as 2008, and interest increases at rate of savings expansion.
4b Copayments expected to increase at rate of program expansion
There is a difference between copayments received in program year (line 4b) from copayments expected from program year installations (line 7a)
In program year copayments are from current and prior year installations; expected copayments from current year installations will be received in current and fuure years
4d Year End fund balance assumes that objective of wiping out negative balance by YE 2008 will be achieved
4 Other sources prior to incremental additional funds from proposed DSM charge increase
6 Program Implementation and Evaluation Expenses are from Planning Model output and summarized in Table 1 of Plan
7b Commitments for future years expected to exceed commitments carried in (see row 4c) due to program expansion
7c Target Incentive is calculated as 4.4% of Spending Budget. Spending Budget is derived from Total Implementation + Evaluation Expenses (line 6) as follows

	2008 Plan	2009	2010	2011
Adjustments to Implementation + Evaluation Expenses (14)				
Exclude EERMC Allocation	-$316,400	-$319,076	-$324,519	-$329,067
Co-Payments difference (see Note 4b) = (7a) - (4b)	$175,205	$87,600	$87,600	$0
Subtotal	**-$141,195**	**-$231,476**	**-$236,919**	**-$329,067**
Total Utility Spending Budget to Achieve Goals = (8) + (14)	**$14,720,160**	**$24,198,830**	**$34,502,053**	**$42,967,233**
Target Incentive = 4.4% x Spending Budget	**$647,687**	**$1,064,749**	**$1,518,090**	**$1,890,558**

9 Program expansion rate is a function of planning model output; this can be adjusted

2009-2011 Energy Efficiency Procurement Plan

Attachment C

Total Resource Cost Test Proposal

Introduction

This document has been prepared pursuant to Section 1,2(A)(ii) of the "Draft Proposed Standards" for the procurement of energy efficiency resources, submitted by the Rhode Island Energy Efficiency Resource Management Council to the Rhode Island Public Utilities Commission, of February 29, 2008 and approved at Open Meeting on June 12, 2008.

As specified in the Proposed Standards,

> (a) The Utility shall assess measure, program and portfolio cost-effectiveness according to the Total Resource Cost test ("TRC")[1]. The Utility shall, after consultation with the Council, propose the specific benefits and costs to be reported and factors to be included in the Rhode Island TRC test.
>
> (b) That test shall include the costs of CO2 mitigation as they are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative. They shall include any other costs associated with greenhouse gas reduction that are actually being imposed on energy generation and can be identified and quantified.
>
> (c) The utility shall provide a discussion of the carbon impacts efficiency and reliability investment plans will create.

And, as further specified in the Proposed Standards (Section 1.3(B)(iii))

> The Utility, in consultation with the Council may propose specific non-energy benefits (NEBs) in its Residential Low Income program cost-effectiveness analysis in addition to the benefits included in the TRC test for all other programs.

Background

Benefit/cost testing considers the dollar value of benefits compared to costs over the expected life of benefits created by an energy efficiency measure, program, or portfolio of programs. Various tests have evolved over time in an attempt to consider cost-

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[1] Since the focus of the Rhode Island legislation is on securing customer benefits, not just Utility benefits from energy efficiency procurement, the TRC test is recommended.

effectiveness from a variety of perspectives. Some differences in application have also evolved in various areas as a way to address specific issues of importance in the area[2,3]. The benefit/cost tests adopted in a particular area reflect the importance that regulators and other policy makers in a jurisdiction place on various factors. The results of the cost-effectiveness assessment can be expressed in a variety of ways, but in all cases it is necessary to calculate the net present value of program impacts over the lifecycle of those impacts.

The Total Resource Cost (TRC) Test Overview

The TRC Test compares the present value of a stream of benefits associated with the **net savings** of an energy efficiency measure or program over the life of that measure or program to the total costs necessary to implement the measure or program. The term "resource" focuses this test on the benefits and costs associated with the acquisition of a resource, in this case, energy efficiency. The discussion below under "Description of Program Benefits and Costs" explains the inclusion of the proposed benefits in the TRC test being proposed for use in least cost procurement of energy efficiency in Rhode Island.

The expected net savings are typically an engineering estimate of savings modified to reflect the actual realization of savings based on evaluation studies. Demand savings are calculated to be coincident with the ISO-NE definition of peak.

The expected net savings also reflect market effects due to the program. The TRC test captures the combined effects of a program on both the participating customers and those not participating in a program. From a resource acquisition perspective, if the program

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[2] An example of this is the Total Resource Cost Test (TRC) that is used in Massachusetts. In the Massachusetts version of the TRC, quantifiable non-resource effects such as benefits unique to low income consumers are included in addition to the dollar value of all resource benefits expected over the life of the installed measures.

[3] Another example is that California does not require program administrators to assess the cost-effectiveness of informational programs in recognition of the challenges associated with evaluating the savings that can be attributed to these programs.

induces participants or non-participants to acquire energy efficiency devices without program expenditures, these effects—known as spillover—should be attributed as program benefits in the TRC Test. The costs incurred by customers to acquire equipment on their own will also be counted as costs in the TRC Test.

If a customer accepts program funds to implement an energy efficiency measure they would have done anyway, the savings associated with this practice is known as "free ridership." From the perspective of resource acquisition through utility programs, it is important to distinguish whether the customer would have implemented the efficiency measure without the program. Therefore, savings associated with free-ridership will be deducted from program savings. Both free-ridership and spillover will be determined from surveys pf program participants, non-participants, and other market actors.

The TRC Test may be applied to any energy efficiency program independent of the primary fuel or resource the effort focuses on.

The TRC test captures the value created by efficiency measures installed in a particular program year over the useful life of the measure. The measure life is based on the technical life of the measure modified to reflect expected measure persistence.

Because the TRC test captures the value associated with a stream of benefits over a period of time, the benefits from a measure are present valued so that costs and benefits may be compared. The benefits calculated in the TRC Test are the avoided resource supply and delivery costs, valued at marginal cost for the periods when there is a load reduction, as well as the monetized value of non-resource savings.

The program costs are those paid by both the utility and by participants plus the increase in supply costs for any period when load is increased. All equipment, installation, O&M, removal, evaluation and administration costs are included.

The benefits and costs recommended for consideration in Rhode Island are detailed in the next section. An example calculation showing the application of the TRC test is included in Appendix A.

Description of Program Benefits and Costs

The following benefits and costs are included in the TRC test. They are listed here with details after.

1) Electric Energy Benefits
2) Electric Generation Capacity Benefits
3) Electric Transmission Capacity and Distribution Capacity Benefits
4) Fuel Benefits (including the value of natural gas savings from natural gas energy efficiency programs)
5) Water and Sewer Benefits
6) "Non-resource" Benefits
7) Price Effects
8) Externalities
9) Utility Costs
10) Participant Costs

1) Electric Energy Benefits.

Avoided electric energy costs are appropriate benefits for inclusion in the TRC Test. When consumers do not have to purchase electric energy because of their investment in energy efficiency, an avoided resource benefit is created. We propose to value the energy savings that we anticipate producing in the Company's first three year plan submitted as part of the Least Cost Procurement Process using the avoided electric energy costs developed in the "Avoided Energy Supply Costs in New England: 2007 Final Report," August 10, 2007, prepared by Synapse Energy Economics, Inc. (the "2007 AESC Report").[4] Values for Rhode Island are found in Exhibit E-1-RI-C$ of the 2007 AESC

[4] The 2007 AESC Study was submitted concurrently with the Settlement of the Parties in Docket 3892. It covers the period from 2007-2040. It has been updated biennially and is expected to be updated during

Report. The values in the 2007 AESC Report represent wholesale electric energy commodity costs. They also include pool transmission losses incurred from the generator to the point of delivery to the distribution companies, the costs of renewable energy credits borne by generators, and a retail adder that captures market risk factors typically recovered by generators in their pricing. As such, the avoided electric energy values represent wholesale market costs that are avoided when generators produce less electricity because of energy efficiency.[5] Losses are included because a reduction in energy use at the customer means that amount of energy does not have to be generated, plus the extra generation that is needed to cover the losses that occur in the delivery of that energy is not needed. The avoided energy costs internalize the expected cost of complying with current regional carbon control requirements, per the Proposed Standards (costs of "CO2 mitigation as they are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative")[6].

The avoided energy costs are disaggregated into four different costing periods consistent with ISO-NE definitions. The time periods are defined as follows:

- Winter Peak: October – May, 6:00 a.m. – 10:00 p.m., weekdays excluding holidays.
- Winter Off-Peak: October – May; 10:00 p.m. – 6:00 a.m., weekdays. Also including all weekends and ISO defined holidays.
- Summer Peak: June – September, 6:00 a.m. – 10:00 p.m., weekdays excluding holidays.
- Summer Off-Peak: June – September; 10:00 p.m. – 6:00 a.m., weekdays. Also including all weekends and ISO defined holidays.

2009 for use beginning with the 2010 program year. If the Company files an update in 2010 or 2011 to the Procurement Plan, it will use the values from the anticipated 2009 AESC Study. There is some belief that the energy values from the 2007 AESC underestimate current avoided costs, because of the rise of fuel prices since the study was completed. To the extent that values are understated, benefits will be understated and the results of the TRC test will be conservative.

[5] Avoided costs may be viewed as a proxy for market costs. However, avoided costs may be different from wholesale market spot costs because avoided costs are based on simulation of market conditions, as opposed to real-time conditions. They may be different from standard offer commodity costs because of time lags and differing opinions on certain key assumptions, such as short term fuel costs.

[6] The 2007 avoided costs also include the value of a projected federal cap and trade system for carbon mitigation. This value will not be included in the Rhode Island benefit/cost analysis until the Federal program is actually put in place, per the standards.

Net energy savings for a program (or measures aggregated within a program) are allocated to each one of these time periods and multiplied by the appropriate avoided energy value.[7] The dollar benefits are then grossed up using the appropriate loss factors representing losses from the ISO delivery point to the end use customer.

- Summer Peak Energy Benefit ($) = kWhNet * $Energy\%_{SumPk}$ * $SumPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{SumPk\text{-}kWh}$)
- Summer OffPeak Energy Benefit ($) = kWhNet * $Energy\%_{SumOffPk}$ * $SumOffPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{SumOffPk\text{-}kWh}$)
- Winter Peak Energy Benefit ($) = kWhNet * $Energy\%_{WinPk}$ * $WinPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{WinPk\text{-}kWh}$)
- Winter OffPeak Energy Benefit ($) = kWhNet * $Energy\%_{WinOffPk}$ * $WinOffPk\$/kWh_{(@Life)}$ * (1 + $\%Losses_{WinOffPk\text{-}kWh}$)

2) Electric Generation Capacity Benefits.

Avoided electric generation capacity values are appropriate for inclusion in the TRC Test. When generators do not have to build new generation facilities or when construction can be deferred because of consumers' investments in energy efficiency, an avoided resource benefit is created. In the New England capacity market, capacity benefits accrue because demand reduction reduces ISO-NE's installed capacity requirement. The capacity requirement is based on load's contribution to the system peak, which, for ISO-NE, is the summer peak. Therefore, capacity benefits accrue only from summer peak demand reduction and are determined by multiplying net peak summer demand savings by avoided generating capacity values and a capacity loss factor. There is currently no winter generation capacity benefit.

We propose to value the demand savings created through program efforts using the avoided capacity values from Exhibit E-1-RI-C$ of the 2007 AESC Report. The values contained in the report reflect the avoided cost of peaking capacity, plus a reserve margin and pool transmission losses incurred from the generator to the point of delivery to the

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[7] The notation "@Life" in the equation for value for this and other value components is an indication that the avoided value component for each benefit (e.g., electric energy, capacity, natural gas, etc.) is the cumulative net present value (in 2009 dollars) of lifetime avoided costs for each year of the planning horizon from the base year over the life of the measure.

distribution companies. ISO-New England ("ISO-NE") reserve margins are incorporated into the capacity values, since energy efficiency avoids the back-up reserves for that generation as well as the generation itself. A loss factor representing losses from the ISO delivery point to the end-use customer is used as a multiplier, since those losses are not included in the avoided costs.

The dollar value of benefits are therefore calculated as

- Generation Capacity Benefit($) = kWSum*AnnualMarketCapValue$/kW$_{(@Life)}$ * (1 + %Losses$_{SumkW}$)

3) Electric Transmission Capacity and Distribution Capacity Benefits.

Avoided transmission and distribution capacity values are appropriate for inclusion in the TRC test. When transmission and distribution facilities do not have to be built or can be deferred because of lower loads as a result of consumers' investments in energy efficiency, an avoided resource benefit is created.

We propose to value the electric transmission capacity and distribution capacity benefits in the TRC test using avoided transmission and distribution capacity values calculated in a spreadsheet tool that was developed in 2005 by ICF International, Inc., the consultant that performed the biennial avoided cost study for New England's energy efficiency program administrators in that year. The tool calculates an annualized value of avoided transmission and distribution capacity values from company-specific inputs of historic and projected capital expenditures and loads, as well as a carrying charge calculated from applicable tax rates and Federal Energy Regulatory Commission ("FERC") Form 1 accounting data. The resulting values are statewide averages. If there are locally constrained areas where the value avoided T&D may be higher, and which may be targeted for a concentrated energy efficiency implementation effort, we will develop a site-specific incremental value of avoided T and/or D capacity that may be added to the average value.

Capacity loss factors are applied to the avoided T&D capacity costs to account for local transmission and distribution losses from the point of delivery to the distribution company's system to the ultimate customer's facility. Thus, losses will be accounted for from the generator to the end use customer.

In theory, the T&D benefits could be allocated to summer and winter periods, depending on the relation between summer and winter peaks on the local system. However, the Company's system has been summer peaking. Therefore, the T&D benefits will be exclusively associated with summer demand reduction and the dollar value will be calculated as follows:

- Transmission Benefit ($) = (kWSum * Trans$/kW$_{(@Life)}$ * [1 + (Losses$_{SumkWTrans}$)]
- Distribution Benefit ($) = (kWSum * Dist$/kWLife$_{(@Life)}$ * [1 + (Losses$_{SumkWDist}$)]

4) Fuel Benefits

Avoided fuel costs (natural gas, propane, or fuel oil) are appropriate for inclusion in the TRC Test. When a project in which consumers have invested to save electricity also saves fuel—for example, a ventilation project that saves electricity by distributing air more efficiently may also save fuel—an avoided resource benefit is created.

We propose value these fuel benefits in the TRC Test using avoided fuel cost values from the 2007 AESC Report. These costs include commodity, transportation, and retail delivery charges that would be avoided by fuels not consumed by end users.

The 2007 AESC Report aggregates and presents monthly avoided natural gas value components into end-use categories to match with individual program characteristics. It also provides fuel oil values for different grades and sectors of fuel oil. The natural gas categories are:

- Commercial and industrial, non-heating. This assumes savings are constant throughout the year and averages monthly natural gas values over 12 months.

- Commercial and industrial, heating. Averages the monthly values for the months of November through March.
- Existing residential heating. Averages the monthly values for the months of December through February. As these months have the highest natural gas values, by averaging over a fewer number of months, natural gas savings in this category typically have the highest value.
- New residential heating. Averages the monthly values for the months of November through March. Since new buildings are assumed to be more efficient than existing buildings, savings from new building programs are worth slightly less than savings that improve efficiency in existing buildings.
- Residential domestic hot water. This assumes savings are constant throughout the year and averages monthly natural gas values over 12 months.
- Non end-use specific values accrue values based on average values for the months of November – April.

The fuel oil categories are Residential #2, Commercial #2, Commercial #4, and Commercial and Industrial #6.

Using these end-use value components, the dollar value of fuel benefits is calculated as:

- Fuel Benefits ($) = MMBTU_Fuel Savings * Fuel$/MMBTU$_{(EndUseCategory,@Life)}$

5) Water and Sewer Benefits.

Water savings created from program efforts should be valued and included in the TRC Test. Water savings can be valued using avoided water and sewer values that are based on average water and sewer rates in Rhode Island. *(Note: These need to be calculated.)*. When a project in which consumers have invested to save electricity also affects water consumption—for example, a cooling tower project that reduces makeup water needed—a resource benefit is created. Depending on the project and metering configuration, changes in water consumption may also affect sewerage billings.

Water and sewer benefits are counted for all projects, where appropriate, and calculated as follows:

- Water and Sewerage Benefits ($) = NetWater and/or Sewerage Savings * Water and/or Sewer $/Gal$_{(@Life)}$

6) "Non-resource" Benefits.

Other quantifiable non-resource effects may be created by program efforts and, are therefore appropriate for inclusion in the TRC Test. In this era of economic uncertainty and concern about environmental sustainability, we believe that the concept of "resources" should be expanded to include the impacts energy efficiency projects have on labor, material, facility use, and transportation. These effects will be included when they are a direct result of the measure and when they are quantifiable and avoidable. Non-resource benefits are typically associated with the number of measures installed, rather than the energy consumption of the equipment.

There are several categories of Non-resource benefits. The treatment of each of these is discussed below:

- Commercial and Industrial prescriptive measures – For prescriptive measures where we assume a baseline and efficient device, we can determine, for example, whether longer measure lives will lead to labor and material savings or where reduced transmission of electric waste heat will increase fuel consumption. These quantifiable benefits will be included.
- Commercial and Industrial custom measures – Custom measures are site-specific, but there may be similarities among groups of projects. However, we have thus far not collected sufficient data to develop reliable predictions of non-resource benefits by end-uses. Therefore, custom non-resource benefits will not be included until more reliable predictions can be made.
- Residential Non-low income – Non resource benefits will be counted for lighting operations and maintenance savings and the laundry detergent savings associated with high efficiency clothes washers.

- Residential low-income – In addition to the non-low income savings, the fire reduction and illness reduction benefits from space heating efficiency improvements will be counted.

Additionally, for low-income customers, there are unique benefits associated with investments in energy efficiency. These include reduced bill arrearages, increase in home value, and other economic effects attributed to reduced electricity bills.

We propose to include in the TRC test non-resource benefit values that are based on engineering and economic analyses. These values have been used in Massachusetts for a number of years and will be updated in 2008. In the updating process, we will assess whether there are any substantive differences between Rhode Island and Massachusetts with respect to non-resource value components.

The dollar value of non-resource benefits will be calculated as follows

- Non-resource benefits ($) = Non-resource benefit ($)/unit * Number of units * Present Worth Factor$_{(@Life)}$

7) Price Effects.

The Demand-Reduction-Induced Price Effect (DRIPE) is the reduction in prices in the wholesale energy and capacity markets resulting from the reduction in need for energy and/or capacity due to efficiency and/or demand response programs. Consumers' investments in energy efficiency avoid both marginal energy production and capital investments, but also lead to structural changes in the market due to lower demand. Over three to five years, the market adjusts to lower demand, but until that time the reduced demand leads to a reduction in the market price of electricity. This is the phenomenon observed currently in the New England market when ISO-New England activates its price response programs. When this price effect is a result of consumers' investments in energy efficiency, it is appropriate to include it in the TRC Test.

DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms over all the kWh transacted in the market. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.

National Grid proposes to use in the TRC Test the DRIPE values developed in the 2007 AESC Report.[8] The price effects are expressed as $/kWh for each of the four energy costing periods and $/kW for capacity. The DRIPE benefit is calculated as

- Summer Peak Energy DRIPE Benefit ($) = kWhNet * $Energy\%_{SumPk}$ * $SumPkDRIPE\$/kWh_{(@Life)}$ * (1 + $\%Losses_{SumPk\text{-}kWh}$)
- Summer OffPeak Energy DRIPE Benefit ($) = kWhNet * $Energy\%_{SumOffPk}$ * $SumOffPkDRIPE\$/kWh_{(@Life)}$ * (1 + $\%Losses_{SumOffPk\text{-}kWh}$)
- Winter Peak Energy DRIPE Benefit ($) = kWhNet * $Energy\%_{WinPk}$ * $WinPkDRIPE\$/kWh_{(@Life)}$ * (1 + $\%Losses_{WinPk\text{-}kWh}$)
- Winter OffPeak Energy DRIPE Benefit ($) = kWhNet * $Energy\%_{WinOffPk}$ * $WinOffPkDRIPE\$/kWh_{(@Life)}$ * (1 + $\%Losses_{WinOffPk\text{-}kWh}$)
- Generation Capacity DRIPE Benefit($) = kWSum * $CapDRIPEValue\$/kW_{(@Life)}$ * (1 + $\%Losses_{SumkW}$)

8) Avoided Externalities

All of the preceding benefits are monetized benefits directly associated with the reduced consumption of electricity or natural gas. There are additional effects of energy efficiency felt outside the actual project itself, and not included in the valuation of the project. These are called externalities.

[8] Consensus was not reached for the inclusion of this benefit in the TRC Test. However, the proposal was accepted by a majority of the Subcomittee members. Some members did not support its inclusion in the TRC test, essentially because they did not think this price effect was a cost that would be avoided bv consumers through an investment in energy efficiency. There were also concerns about the magnitude of the benefit.

Per the proposed standards, externalities will not be included in the calculation of benefits. Externalities will be considered in the sensitivity analysis identified in Section 1.3(B)(v) of the proposed standards. The Company proposes to use the externality values from the 2007 Avoided Cost Report in the sensitivity analysis.[9]

9) Utility Costs

Utility costs incurred to achieve implementation of energy efficiency measures and programs are appropriate for inclusion in the TRC Test. These costs have been categorized in prior years in Rhode Island in the following categories:

- Program Planning and Administration (PP&A): This is comprised of external and internal costs. External PP&A costs are the costs associated with vendor or third party management of program delivery. Internal PP&A costs are the costs of the utility role in program delivery, including payroll, contract administration, and overhead expenses. Each of these may include sales, training of program delivery personnel and technical assistance as well.
- Marketing: These are the costs of marketing and advertising to promote a program.
- Rebates and Other Customer Incentives: These are the incentives from the programs to customers to move them to install energy efficient equipment. They may be in the form of rebates to customers, copayments to vendors for direct installation of measures, or payments to distributors to buy down the cost of their products for sale in retail stores. Customer incentives typically cover a portion of the equipment and installation costs directly associated with the energy efficient equipment being installed.[10] For a retrofit project, the customer incentives cover a portion of the full cost of the efficiency project, as it is assumed that the alternative to the project is no customer action. For a failed equipment replacement/renovation/new construction

[9] The values in the 2007 AESC Report reflect the difference between what is considered to be the cost of controlling carbon to a sustainable level and the costs of carbon mitigation—based on anticipated Regional Greenhouse Gas Initiative ("RGGI") and federal requirements—that are internalized into the avoided energy costs.

[10] The full cost of the efficiency project is not necessarily the same thing as the full cost of the project being undertaken by the customer. For example, a customer may be renovating an HVAC system including installation of a new chiller and chilled water distribution. While the new distribution system may be part of the construction project, if it does not contribute to energy savings, it will not be included in the efficiency project cost; only the incremental cost of the new efficient chiller will be considered.

project, these customer incentives cover a portion of the incremental additional costs associated with moving to a higher efficiency item or practice compared to what the customer would have done otherwise.

- Evaluation and Market Research. These are the costs of market research to support program direction and post-installation studies to study program effectiveness or verification of savings estimates.
- Shareholder Incentive. This is the incentive received by the Company for meeting specified savings goals and/or performance targets; because the Company would not implement energy efficiency programs to the extent it does without the incentive, the shareholder incentive is included in the cost of energy efficiency.

10) Customer Costs

The customer's costs include their contribution to the installation cost of the efficient measure. Typically, this is the portion of the equipment and installation cost not covered by the customer incentive. It excludes the cost of equipment that might be part of the customer's construction project, but that is not related to the energy efficiency portion of the project.

Benefit/Cost Calculations

The cost effectiveness of a measure, program, or portfolio is simply the ratio of the net present value of the benefits to the net present value of the costs.

For the Procurement Plan which covers the years 2009-2011, all costs and benefits will be expressed in constant 2009 dollars. Where escalation of benefits (avoided costs) and costs is needed, appropriate inflation rates will be used.

The avoided value component for each benefit (e.g., electric energy, capacity, natural gas, etc.) is the cumulative net present value (in 2009 dollars) of lifetime avoided costs for each year of the planning horizon from the base year. For example, the avoided value component in Year 10 for any given benefit is the sum of the net present value of the annual avoided costs for the resource for Year 1, Year 2, Year 3, etc., through Year 10, in 2009 dollars. This value is applied to the annual savings for a measure with a 10-year life to generate the lifetime avoided benefit for that measure. Since all of the future year values are in constant 2009 dollars, lifetime benefits thus calculated are discounted back to mid-2009 using a real discount rate equal to [(1 + Nominal Discount Rate) / (1 + Inflation)] - 1. For the Procurement Plan submitted for Council consideration, a nominal discount rate of 4.9% and an inflation rate of 1.9% were used, identical to the assumptions used in the 2008 Program. The low discount rate reflects the relative lack of risk in the investment in energy efficiency.[11]

The total benefits will equal the sum of the NPV of each benefit component:

[Energy Benefits + Generation Capacity Benefits + Avoided T&D Benefits + Fuel Benefits + Water & Sewer Benefits + Non-Resource Benefits + Price Effects Benefits + Externality Benefits (in scenario analysis only)]

The total costs will equal the sum of the NPV of each cost component:

[Program Planning and Administration + Marketing + Rebates and Other Customer Incentives + Evaluation and Market Research + Shareholder incentive]

The TRC benefit/cost will then equal:

Total NPV Benefits/Total NPV Costs

On a program level, all benefit categories are included in the benefit/cost calculation. All cost categories, except the shareholder incentive, are included because they are tracked at a program level.[12]

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[11] Other discount rates, such as the interest rate on a 10 year government security, such as a T-Bill, may be appropriate if they similarly reflect the lack of risk associated with the investment.

[12] While commitments of customer incentives made from one year to the next are included in the program budgets, they are excluded from the program costs used in the benefit/cost calculation . The costs are only counted in the year in which the incentive is paid and the savings are counted.

On a portfolio level, the shareholder incentive received (or expected to be received if goals are achieved when looking at cost-effectiveness prospectively) by the Company, will be included with the other costs in the determination of cost effectiveness.[13] The shareholder incentive is included at this level because it is designed to achieve overall procurement goals which are reflected in overall portfolio performance, and not the performance of a particular program or sector.

Separate calculations of benefits and cost-effectiveness are provided for the electric energy efficiency programs and natural gas energy efficiency programs. Some electric energy efficiency programs are expected to produce natural gas savings in addition to electricity savings while some natural gas energy efficiency programs are expected to produce electricity savings in addition to natural gas savings. All of the resource benefits produced by a program are shown with that program. For example, an ENERGY STAR® clothes washer incented through the electric ENERGY STAR® Products Program will produce natural gas savings when natural gas is used by the participant to heat water.

[13] Costs of any education and training programs that do not generate savings and of R&D efforts with uncertain outcomes will also be included in the portfolio assessment of cost effectiveness, as proposed in the standards.

APPENDIX A

Sample Calculation of Benefits and Costs Using the Proposed TRC Test

Program Description:

Small Business Services Program, involving the direct installation of measures in small business customer facilities

Savings and costs sassumptions:

- 11,528,970 gross kWh savings; 51% winter on-peak; 15% winter off peak; 26% summer on-peak; 8% summer off peak.
- 2671 gross kW summer coincident demand savings
- 12 year life
- Non-resource benefits: $170,629 in operations and maintenance savings
- Utility Costs: $4,604,871
- Customer Costs: $1,973,516
- Free Ridership: 2%
- Spillover: 0%

Benefits ($/kWh and $/kW values used here are cumulative values discounted over the 15 year measure life)

- Summer On-Peak Energy Benefit = 11,528,970 kWh * 26% * 1.059 loss factor * (1- 2% free ridership + 0% spillover) * $1.019/kWh = $3,170,006
- Summer Off-Peak Energy Benefit = 11,528,970 kWh * 8% * 1.03 * (1- 2% + 0%) * $0.685/kWh = $637,726
- Winter On-Peak Energy Benefit = 11,528,970 kWh * 51% * 1.059 * (1- 2% + 0%) * $0.966/kWh = $5,894,675
- Winter Off-Peak Energy Benefit = 11,528,970 kWh * 26% * 1.03 * (1- 2% + 0%) * $0.709/kWh = $2,145,228
- Summer Capacity Benefit = 2,671 kW * 1.095 loss factor * (1- 2% + 0%) * $1,135.73/kW = $3,255,286
- Transmission Capacity Benefit = 2,671 kW * 1.095 loss factor * (1- 2% + 0%) * $401.07/kW = $1,149,567

- Distribution Capacity Benefit = 2,671 kW * 1.095 loss factor * (1- 2% + 0%) * $1,171.45/kW = $ 3,357,669
- Fuel Benefit: None
- Water and Sewer Benefit: None
- Non-Resource Benefit: $170,629 * (1- 2% + 0%) * 10.13 present worth factor = $1,693,902
- DRIPE Summer On-Peak Energy Benefit = 11,528,970 kWh * 26% * 1.059 loss factor * (1- 2% free ridership + 0% spillover) * $0.196/kWh = $609,736
- DRIPE Summer Off-Peak Energy Benefit = 11,528,970 kWh * 8% * 1.03 * (1- 2% + 0%) * $0.088/kWh = $81,926
- DRIPE Winter On-Peak Energy Benefit = 11,528,970 kWh * 51% * 1.059 * (1- 2% + 0%) * $0.119/kWh = $726,156
- DRIPE Winter Off-Peak Energy Benefit = 11,528,970 kWh * 26% * 1.03 * (1- 2% + 0%) * $0.097/kWh = $ 293,494
- DRIPE Capacity Benefit = 2,671 kW * 1.095 loss factor * (1- 2% + 0%) * $248.75/kW = $712,980

Total Benefit = $23,728,351

Total Cost = $6,578,387

TRC ratio = $23,728,351 / $6,578,387 = 3.6

ATTACHMENT D

2009 RI Incentive Proposal: same as incentive mechanism approved for 2008

Incentive Rate: 4.40%

	Sector	(1) Spending Budget	(2) Incentive Rate	(3) Target Incentive	(4) Target Incentive for Performance Metrics	(5) Target Incentive - Annual kWh Savings	(6) Annual kWh Savings Goal	(7) Threshold kWh Savings	(8) Target Incentive Per kWh	(9) Incentive Cap - Annual kWh Savings
	Residential	$5,284,732		$236,627	$40,000	$196,627	15,908,740	9,545,244	$0.012	$245,784
	Small Commercial & Industrial	$3,479,808		$149,472	$20,000	$129,472	8,698,030	5,218,818	$0.015	$161,840
	Large Commercial & Industrial	$5,955,670		$261,590	$40,000	$221,590	30,196,093	18,117,656	$0.007	$276,988
2008	Total	$14,720,210	4.40%	$647,689	$100,000	$547,689	54,802,862	32,881,718		$684,611

	SECTOR BUDGETS AND GOALS FOR 2009 TO BE DETERMINED AND INCLUDED IN ENERGY EFFICIENCY PROGRAM PLAN									
2009	Total	$24,198,830	4.40%	$1,064,749	$100,000	$964,749	74,387	44,632		$1,205,936

Notes:
(1) Sector budget net of projected commitments, copayments, and EERMC allocation
(2) 4.40% of the sector spending budget.
(3) Target Incentive Total = Incentive Rate x Spending Budget Total (Column (1)).
(4) $20,000 per proposed performance metric.
(5) Total for Column (3) - Total for Column (4) allocated to sectors based on the relative size of the spending budget in the sector.
(6) Goal for annual kWh savings by sector. This may be adjusted at year end for evaluation results and actual spending relative to the spending budget. If goal is adjusted, values in columns (7), (8), and (9) will be adjusted as well.
(7) 60% of Column (5). No incentive is earned on annual kWh savings in the sector unless the Company achieves at least this threshold level of
(8) Column (5)/Column (6). Applicable to all annual kWh savings up to 125% of target savings if at least 60% of target savings have been achieved.
(9) Column (5) x 1.25.