Synapse
Energy Economics, Inc.

White Paper

Least Cost Electricity Procurement for Standard Offer Service in Rhode Island

Prepared by:
Rick Hornby, Bruce Biewald, and William Steinhurst
Synapse Energy Economics
22 Pearl Street, Cambridge, MA 02139
www.synapse-energy.com
617-661-3248

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White Paper

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Executive Summary

In June 2006 Rhode Island enacted the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 ("2006 Act"). One of the highlights of the 2006 Act is the establishment of a "least-cost procurement" (LCP) requirement with the goal of meeting electrical energy needs in Rhode Island in a manner that is "…optimally cost-effective, reliable, prudent and environmentally responsible." The Act requires the Office of Energy Resources (OER) as well as the Energy Efficiency and Resources Management Council to provide the Public Utilities Commission (PUC) with recommendations regarding procurement of system reliability and energy efficiency resources by March 1, 2008 and every three years thereafter. The PUC is required to solicit input on standards required to implement LCP, and to issue those standards by June 1, 2008.

This paper provides a summary overview of the background to, and context for, implementation of LCP in Rhode Island and an outline of the major issues associated with that implementation. The paper provides background indicating that:

- The LCP portion of the 2006 law provides Rhode Island with a policy framework and approach for meeting the electrical needs of its citizens at lower expected costs, and with lower expected environmental impacts, than would otherwise occur. These reductions will result from meeting a portion of those needs from a mix of efficiency resources and system reliability resources (e.g., diverse sources, including renewable energy resources, distributed generation, demand response), thereby displacing a corresponding quantity of supply from conventional generation;

- The future contribution that each category of resources will ultimately make to an LCP portfolio will be influenced by the technical and economic attributes of each resource, the future design and operation of the wholesale electricity market, new regional and federal environmental policies, and the regulations that the PUC establishes to implement LCP in Rhode Island.

- The Stakeholders of the Rhode Island Greenhouse Gas (GHG) Process (Stakeholders) have the opportunity to provide input into the OER's recommendations, and ultimately into the PUC proceeding regarding regulations to implement LCP. They may wish to consider providing input regarding several aspects of those standards, including:
    - a standard that will support effective procurement of all energy efficiency resources costing less than additional electricity supply;
    - the standard regarding contractual approaches for procurement of renewable energy resources;
    - standards for "cost-effective" and "environmentally responsible" to be used in the determination of whether a candidate portfolio is "optimal"; and

- the treatment of potential stranded costs as a result of an LCP approach.

The combined impact of these standards will be to help achieve the goal of pursuing a multitude of different resources – efficiency, demand response, renewables, and clean generation.

1. Introduction

On June 29, 2006 the Governor of Rhode Island enacted the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 ("2006 Act"). A key highlight of the 2006 Act is the requirement that electric distribution utilities[1] (EDUs) increase their reliance on energy efficiency services by providing them whenever the cost of saved energy is less than the cost of additional supply.[2]

The legislation requires (EDUs) to continue providing standard power supply service, i.e., standard offer service (SOS) through 2020. (The vast majority of customers in Rhode Island are currently on standard offer, e.g., 99 percent of National Grid customers.) Under the "least-cost procurement" (LCP) requirement in the 2006 Act, EDUs must provide SOS using a mix of separate but complementary portfolios of conventional supply and LCP resources, including energy efficiency and system reliability resources. The mix of conventional supply and LCP resources must meet the electrical energy needs of customers in a manner that is "…optimally cost-effective, reliable, prudent and environmentally responsible." The quantities of energy efficiency and system reliability resources to be procured are to be subject to standards established by the PUC[3] and the costs of those resources are to be recovered in the charge for standard power supply service (standard offer or SOS).[4]

The "supply" category is not new. It is essentially generation purchased from conventional sources. The electric distribution companies are currently acquiring supplies from this category in order to provide their Standard Offer (SOS) and Last Resort (LRS) services and have been doing so since 1997, when the restructuring of the state's electric market took effect. At that time the supply function was unbundled from the distribution function and opened to competition under which retail customers were allowed to shop for their supply. Retail customers who did not choose a competitive supplier were placed on SOS. Retail customers who left SOS, and subsequently were not being served by a competitive supplier, were placed on Last Resort Service (LRS). The distribution utility acquires supplies for SOS and for LRS through separate portfolios of contracts. The contracts used to supply SOS service are long-term contracts that expire in 2009. The contracts used to supply LRS are short-term, e.g., a year or less in duration. At this point the vast majority of small and medium size customers in the residential, commercial and industrial classes are on SOS, with a number of large customers on LRS and competitive supply. For example, as of December 2006, 99.1% of NGRID customers accounting for 83% of its electricity deliveries were on SOS. Only 0.2% of its customers were

[1] Narragansett Electric (National Grid), Pascoag Utility District, Block Island Power Company
[2] RIGL 39-1-27.7(a)(2)
[3] RIGL 39-1-27.7 (c) (4).
[4] RIGL 39-1-27.3 (b).

on LRS and 0.7% on competitive supply. The latter two groups are very large customers, with monthly usage 20 to 30 times more than the average SOS customer.[5]

Energy efficiency resources are also not new. For many years Rhode Island electric distribution utilities have been providing energy efficiency, or "demand side management" programs to all customers, regardless of from whom those customers purchase their supply service. The cost of these programs has been recovered by a Systems Benefit Charge (SBC) applied to distribution service,[6] which is currently set at 2 mills, or 0.2 cents/kwh. That charge produces about $20 million a year, which is well below the amount that would be required to procure all cost-effective energy efficiency.[7] As noted earlier, what is new is the increased emphasis the 2006 Act places on energy efficiency, by requiring LCP to include energy efficiency resources that are lower cost than additional supply.

The Act identifies system reliability as an explicit new category of resources. This new category includes supply from diverse resources, including renewable resources, distributed generation (DG) and demand response (DR). Of these three, the 2006 Act only applies an explicit cost-effectiveness requirement to DG. The Act does not explicitly link procurement of renewable resources in this category to the procurement of renewables to satisfy the Renewable Energy Standard (RES) law and regulations, which require entities serving end-use customers to meet 16% of their retail sales from renewable resources by 2020. Thus, it is our understanding that the LCP provisions of the 2006 Act contemplate acquisition of renewable resources in excess of the RES requirements

The Act requires the Office of Energy Resources (OER), as well as the Energy Efficiency and Resources Management Council, to provide the PUC with recommendations regarding procurement of system reliability and energy efficiency resources by March 1, 2008 and every three years thereafter. The PUC is required to solicit input on standards required to implement LCP, and to issue those standards by June 1, 2008.

At their November 2006 meeting the Stakeholders expressed interest in providing input to the OER, and ultimately to the PUC, on this issue. In February 2007 the Stakeholders retained Synapse Energy Economics (Synapse) to prepare a white paper on LCP implementation to provide the Stakeholders with a basis for the development of principles, options, and potentially recommendations which they could submit to the OER. The paper is designed to provide the Stakeholders with a summary of the context for implementation of LCP in Rhode Island and an outline of the major issues associated with that implementation.

The paper[8] presents the issues associated with implementing LCP in five sections:

- illustrative impacts of implementing LCP;
- issues associated with the implementation of LCP;
- developments in other states;

[5] National Grid, *Docket 2515 – Open Access Customer Data Report, Fourth Quarter 2006*. February 8, 2007.
[6] This type of charge is sometimes referred to as a "wires" charge to distinguish it from a supply service charge.
[7] Sedano, R. and Murray, C., *Energy Efficiency in New England: Resource Opportunities.* Regulatory Assistance Project for US Environmental Protection Agency. 2007.
[8] A draft of this paper was discussed at the April 26, 2007 meeting of the stakeholders.

- potential options for LCP standards; and
- conclusions.

2. Illustrative Impacts of Implementing LCP

What will the LCP mean in practice? For example, what quantity of each resource will an EDU select and on what basis? How different will the utility's portfolio and the bills of SOS customers look compared to those under the policies to date? This section addresses those questions by illustrating the potential impacts of implementing LCP. To do this we use an example that compares the mix of resources used to meet the electrical needs of Rhode Island retail customers in 2005 with a possible mix to meet the same level of needs in 2020 under an LCP approach.

A. Illustrative Energy Mix and Impacts on Hourly Demand

The energy mix example in Figure 1 uses illustrative load data for Rhode Island and supply data for the New England wholesale electricity market as well as a number of assumptions to develop a LCP and RES scenario for 2020 to meet the same total level of electrical needs.

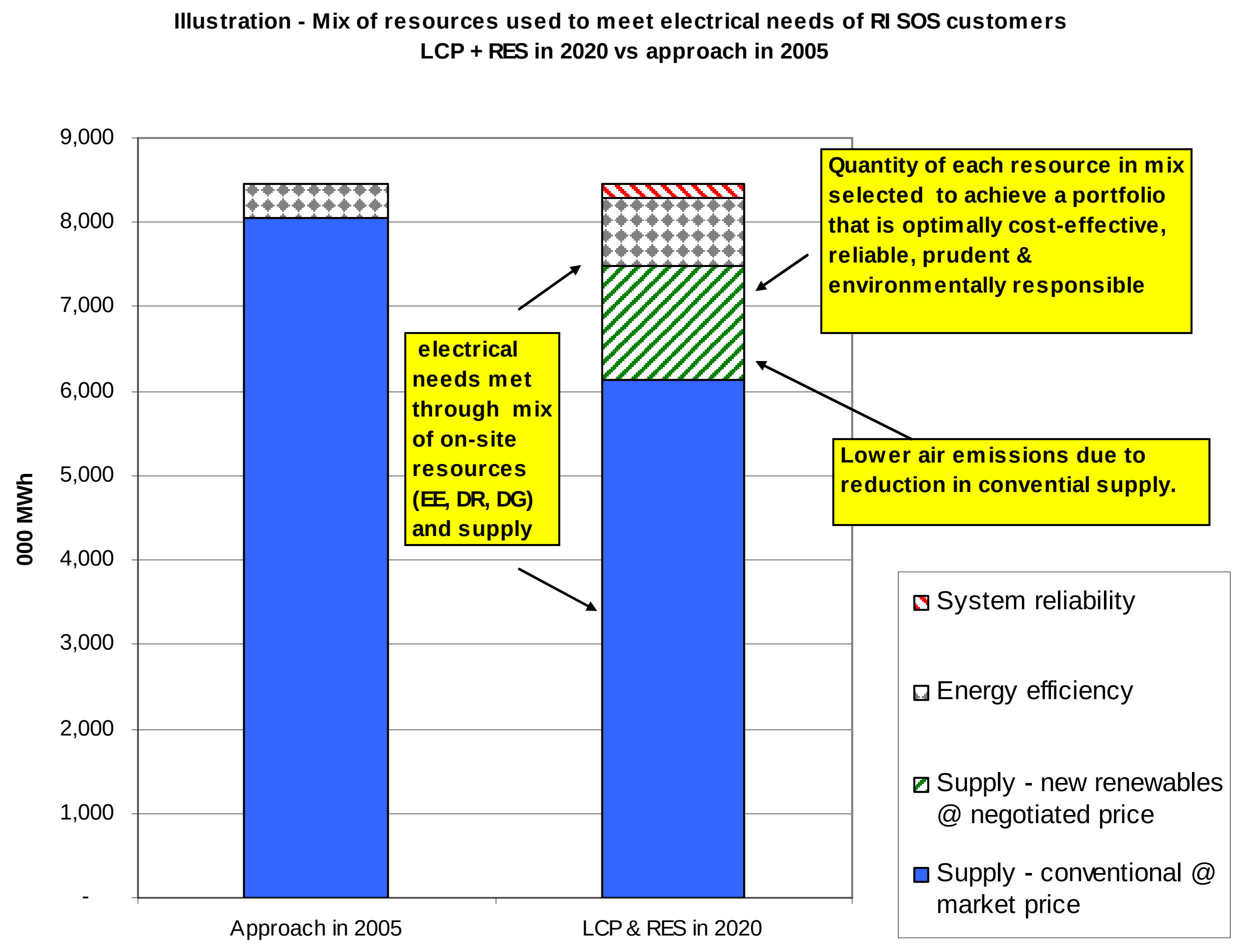
For our illustrative energy mix in 2020 we assume that the electric companies procure a portfolio of energy efficiency, system reliability, RES renewables and conventional supply resources. The assumptions, while within the realm of possibility, are simply to illustrate the differences between the two approaches. These assumptions are consistent with the results of long-term plans we are seeing in other jurisdictions.

The major sources of energy efficiency savings in the commercial and residential sectors are likely to be lighting, heating ventilation and air conditioning (HVAC), and water heating.[9] The system reliability resources may include renewable energy resources, with or without renewable energy credits (RECs). Those renewable energy resources would be in addition to the quantity of renewable resources the EDUs are required to acquire in order to satisfy the RES requirements.

The resulting portfolio consists of system reliability 2%, energy efficiency 10%, large scale renewables at negotiated prices 16%, and conventional supply 74%. (The percentage assumed for renewables is 18% of retail supply, slightly higher than the RES target for 2020, which translates into 16% when expressed as a percentage of total retail electrical needs.)

[9] Optimal Energy, Inc. 2004 updated 2005. *Economically Achievable Energy Efficiency Potential in New England*. Prepared for Northeast Energy Efficiency Partnership. http://www.neep.org.

Figure 1 – Illustrative Energy Mix



Energy efficiency programs will lead to reductions in customer energy consumption potentially across every hour of the year. In addition to those reductions, demand response programs can achieve further energy and cost reductions in the limited number of peak hours each year when the price of electric energy from the wholesale market is highest. The next two Figures show the potential benefits from demand response. Figure

2 presents a plot of total electricity demand in Rhode Island in each hour of the year.

Figure 2 - Hourly Demand in Rhode Island

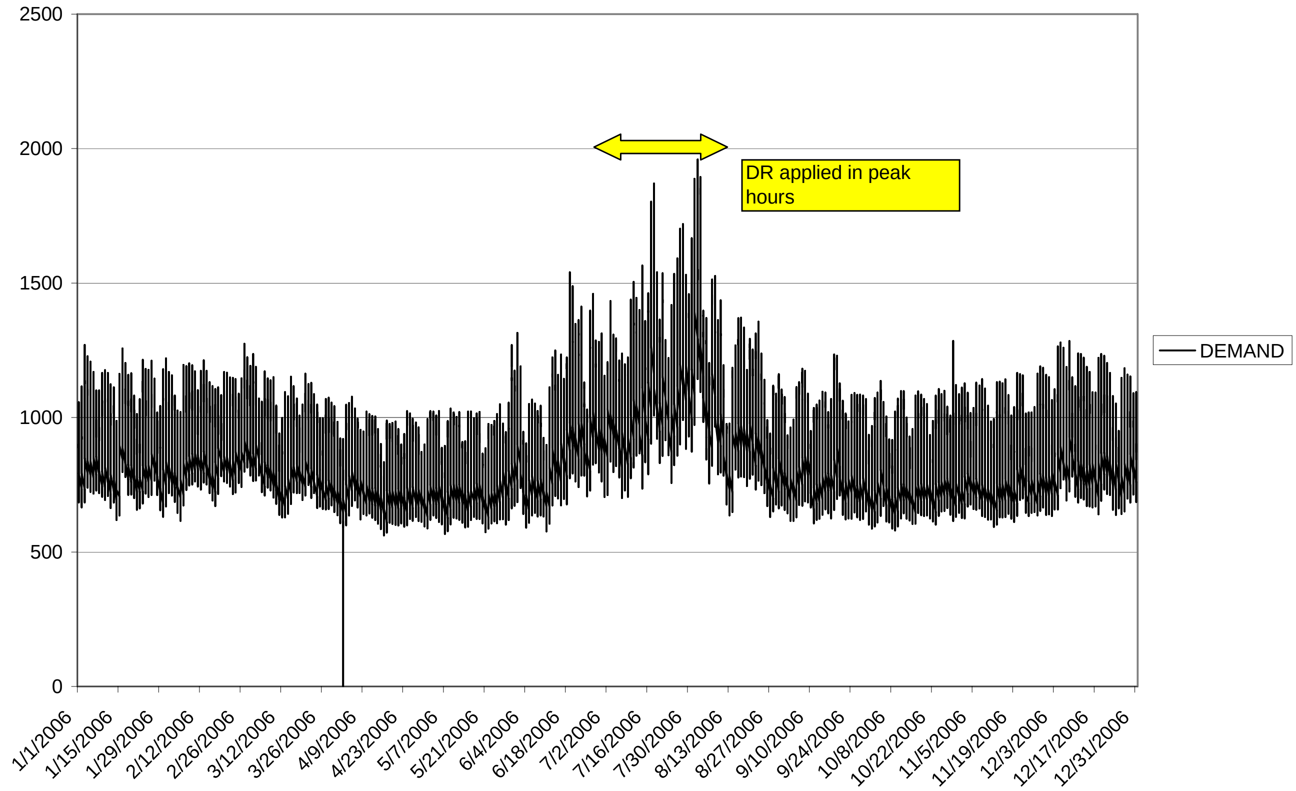
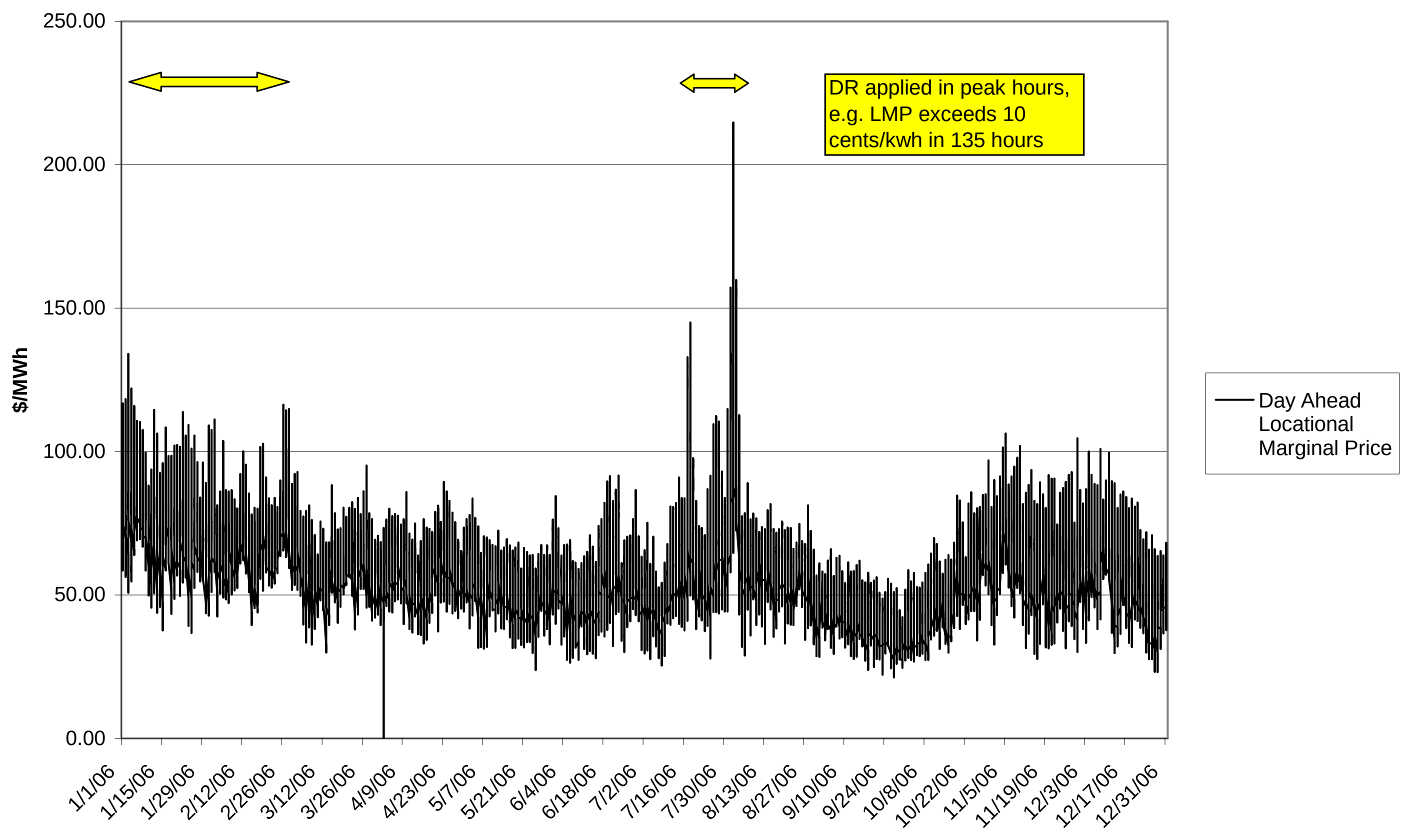


Figure 3 presents the prices during the corresponding hours. Demand response programs, by reducing energy use during the limited number of hours in the year with the very highest demand and prices, e.g., greater than 10 cents/kwh, have the potential to reduce the wholesale market price of electricity in those hours. The reductions in demand from DR will translate into lower annual energy bills. Demand response programs may reduce load in peak hours through efficiency improvements, shifting a portion of peak load to non-peak hours and meeting a portion of peak load through on-site generation.

Figure 3 - Wholesale Electric Energy Prices - RI 2006



The potential impacts of implementing an LCP approach indicated by these changes in the illustrative mixes of capacity and energy include:

- Procurement of energy efficiency resources. What quantity of cost-effective energy efficiency is available? What is the best way to acquire energy efficiency?
- Procurement of system reliability resources. What quantity of renewable energy, distributed generation, and demand response is available? What is the best way to acquire those resources?
- Procurement of an optimal mix of energy efficiency, system reliability, RES and supply resources. What are the appropriate relative quantities or percentages of each resource within the portfolio and what criteria should be used to make that determination?

The balance of this section discusses these potential impacts. Section 3 addresses the issues associated with achievement of those impacts and Section 4 presents potential options for standards to implement the necessary changes in resource procurement.

B. Energy Efficiency Resources

Under an LCP approach electric distribution companies will likely meet a higher percentage of the electrical needs of customers on SOS using energy efficiency. Recent studies by Optimal Energy,[10] the Massachusetts Division of Energy Resources,[11] and the California Public Utilities Commission[12] indicate that electrical needs met through efficiency cost about 3 cents/kwh, approximately 1/3 the current price for SOS. This cost of saved energy (CSE) reflects the total amount paid for the efficiency measure, i.e., the amount paid by the participating customer as well as the amount paid by the utility.

In 2005, under the current approach of SBC funding, the portion of electrical needs of customers met through energy efficiency was in the order of 5% to 6%, or 400,000 MWh. This is an estimate of the cumulative impact of the efficiency programs implemented to date.[13] The aggregate contribution from efficiency has been limited by the statutory cap on ratepayer funding of energy efficiency programs and other factors. The PUC has approved an annual energy efficiency budget for NGRID[14] in 2007 of $ 22.5 million that is funded by a charge of 2 mills (0.2 cents/kwh) that NGRID collects from every customer, regardless of from whom the customer buys its supply. NGRID expects that these programs will produce annual savings of 62,600 MWh. By comparison, Rhode Island electric distribution companies acquired 8,000,000 MWh of conventional supply to meet the consumption portion of electrical needs in 2005.

The 2006 Act does not eliminate the SBC programs. Therefore, one of the issues associated with implementation of LCP will be the relationship between the energy efficiency programs the EDU provides to all customers through SBC funding, and the energy efficiency it provides to SOS customers as part of its portfolio.

C. System Reliability Resources

A second major impact of an LCP approach is that electric distribution companies are expected to procure system reliability resources, including renewable energy. The quantity of renewable energy, when considered in conjunction with the RES, could be significant.[15] Key questions in this regard include the quantity of renewable energy that will be available and the contractual arrangements through which utilities should acquire these resources.

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[10] Ibid.

[11] Massachusetts Division of Energy Resources *Massachusetts Saving Energy*, April 2, 2007

[12] California Public Utilities Commission (CPUC), *INTERIM OPINION: ENERGY EFFICIENCY PORTFOLIO PLANS AND PROGRAM FUNDING LEVELS FOR 2006-2008 – PHASE 1 ISSUES*, Decision 05-09-043, September 22, 2005

[13] York, Dan and Kushler, Martin. *A Nationwide Assessment Of Utility Sector Energy Efficiency Spending, Savings And Integration With Utility System Resource Acquisition*, American Council for an Energy-Efficient Economy, 2006

[14] NGRID delivers the vast majority of the electricity consumed in the state.

[15] Applied Technology and Management, Inc. et al, *RIWINDS Phase I: Wind Energy Siting Study*, April 2007, http://www.riseo.ri.gov/

Utilities in Rhode Island and elsewhere in New England have to meet a portion of the supply for SOS with renewable energy. In Rhode Island this is governed by the RES.[16] Currently, NGRID is accomplishing this by buying conventional commodity SOS supply (without regard to the resources generating such supply) under short-term contracts and by separately buying the necessary level of "renewable energy certificates" (RECs). Thus, a utility might pay 8.0 cents/kwh[17] for the energy and more than 5.0 cents for the REC. An alternative approach would be to enter long-term contracts with project developers for the output of their renewable energy projects. That approach could be instrumental in helping the project get financed and could be less costly to customers in the long-term, if the developer were willing to sell that energy and its associated renewable attribute at an attractive total price, e.g., less than 13.0 cents in our example.[18] Longer-term contracts enable developers seeking financing for capital-intensive resources, such as wind, hydroelectric and solar, to amortize those fixed costs over a greater period and reduce project risk, leading to expectation of lower cost.

Because RECs for RES compliance may be purchased separately from the associated energy or as RECs bundled with energy (and capacity, and in some instances, ancillary services), there are three alternative procurement approaches that can be considered as part of an LCP.

- RECs can be purchased unbundled from electricity;
- electricity and RECs can be purchased bundled together in equal quantities; or
- renewable energy could be purchased without the accompanying RECs.

The first two options are alternative strategies for RES compliance.[19] The last option is not a strategy for RES compliance nor does it provide the buyer with a greenhouse gas benefit for those energy purchases. However, this option does support the development of new renewable generation projects by providing these projects with a stable stream of revenue for their energy and capacity, and by allowing them to sell their RECs to buyers in other states. In other words, acquisition of energy supply from renewable energy generators in excess of the RES targets could be part of an LCP portfolio if procurement of that renewable generation is cost-effective.

The EDUs collect a charge, currently set at 0.3 mills or 0.03 cents/kwh, from all distribution service customers to fund renewable energy programs operated by the OER. As with energy efficiency, one of the issues regarding procurement of renewable resources that will have to be resolved is the future relationship between the OER renewable energy programs and the renewable energy resources that EDUs acquire as part of their SOS portfolio.

[16] In other states the comparable standard is referred to as a Renewable Portfolio Standard (RPS).
[17] If the output from renewable projects is bid into the wholesale market and then acquired by utilities for SOS supply at short-term market prices, the utilities will pay the "market price" for that renewable energy and the market price will continue to be set by natural gas units in most hours for many years, as discussed in Attachment 1.
[18] On April 18, 2007 the OER released a study, RIWINDS, evaluating the feasibility of one or more major wind farms off Rhode Island, including alternative methods of financing such a project.
[19] Narragansett Electric Co.'s 10/11/05 comments on proposed RES rules (at p.2): "We believe that, over the long term, compliance with the RES obligations will be achieved most efficiently if wholesale and retail suppliers purchase both the energy and the certificates from the renewable energy generators."

D. Conventional Supply Resources

A third impact of an LCP approach is that, even with increased emphasis on energy efficiency, system reliability, and RES resources, supply procured from conventional resources could continue to represent the majority of the portfolio used to provide SOS. One of the questions raised by a continued significant dependence on conventional supply is the extent, if any, to which the LCP provisions apply to the acquisition of those conventional resources. As noted earlier, the 2006 Act indicates that it is not just LCP, but instead the **combination** of LCP and supply procurement that has "…as a common purpose" the meeting of electrical needs in a manner that is "…optimally cost-effective, reliable, prudent and environmentally responsible." Resolving the question of the applicability of those goals to supply procurement may require a legal interpretation, which is beyond the scope of this report.

E. Optimal Mix of Efficiency, System Reliability, RES, and Conventional Supply

EDUs will have to provide SOS using a broader range of resources under the LCP than under the current approach of purchasing an undifferentiated mix of conventional supply. This requirement raises the question as to the basis upon which the EDU will determine the quantity of energy efficiency and system reliability resources to procure. Since those resources are installed and operated at customer sites, customers will have a direct input regarding the quantities of energy efficiency and system reliability that will be available. The EDU will exercise some influence on customer acceptance and use of these resources through price signals and program design, but it will not have complete control over the number of installations.

As part of the standards it establishes for implementation of LCP, the PUC may wish to require quantitative estimates of the implications of including various quantities of each category of resource in the portfolio, as well as of the implications of alternative procurement arrangements, such as contract terms of various durations and/or of alternative contract pricing provisions. The purpose of such a requirement would be to help the PUC determine whether a particular portfolio represents an optimal mix that represents a reasonable tradeoff among cost-effectiveness, reliability, prudence, and environmental responsibility.

Consider the illustrative comparison in Figure 1, which implies that an LCP approach would have lower environmental impacts than would otherwise occur, but says nothing about the costs that customers would see on their average bill under each approach. In order to inform that debate and to indicate the type of quantitative analysis that the PUC may wish to require regarding the appropriate percentages of system reliability, energy efficiency, and supply resources under a particular LCP portfolio, we have prepared a simplified illustrative estimate of the impact on an average bill of alternative portfolios by making various assumptions about the costs of resources presented in Figure 1.

In any discussion of future costs or cost-effectiveness, it is important to recognize the uncertainty associated with projections of many categories of costs, particularly fuel prices. For further discussion see Attachment 1. Any such analysis needs to be presented in terms of the probability of achieving lower costs than would be experienced in the absence of LCP. One illustration based upon a set of mix and cost assumptions is presented in Table 1.

Table 1 – Illustrative Monthly Bills for SOS[20]			
utility rate for resource (cents/kwh)	**Approach in 2005**	**LCP & RES in 2020**	
		Scenario A New renewable @ 7 cents/kwh	**Scenario B New renewable @ 9 cents/kwh**
System Reliability @ 0.2	0 %	2 %	2 %
Energy Efficiency @ 0.4	0 %	10 %	10 %
New Renewables	0 %	16 %	16 %
Conventional Supply @ 7.7	95 %	72 %	72 %
Total SOS Portfolio	100 %	100%	100%
Monthly bill (average of all customer classes)	$108	$ 94	$ 98
Air emissions index[21]	100	76	76

This illustration is conservative in that it does not consider an increase in the market price of conventional generation due to increases in fuel prices or carbon regulation.

Another point that one can draw from the illustrative analysis in Table 1 is the importance of selecting an appropriate reference point for measuring cost-effectiveness and/or comparing the cost implications of alternative approaches. When comparing expected costs or bills under one portfolio to those under a different portfolio it is important to calculate the costs over the same timeframe and to capture in the calculation, or at least to acknowledge, any differences in the certainty of the underlying estimates of prices and costs. For example, do both supplies offer the same price stability? This is particularly relevant when comparing projections of costs for supply from generation from volatile commodities, such as natural gas, to projections for energy savings or generation, such as wind, with more certain costs.

3. Issues Associated with Implementation of LCP

This section discusses three issues that may need to be resolved in order to implement LCP. First, there may be a need to clearly identify the applicability of the LCP provisions of the 2006 Act to various resources and entities. Second, there will be a need to establish a standard for cost-effectiveness, including the treatment of uncertainty in the application of that standard. Third, there may be a need to address concerns regarding the risk of stranded costs.

[20] Assumes average monthly electrical need of 1,467 kwh based on total Rhode Island sales in 2005 and total number of customers. Energy Information Administration, *State Energy Profiles 2005*, page 200.
[21] This assumes air emissions are directly proportional to the quantity of conventional supply.

A. Interpretation of LCP provisions

There appears to be some ambiguity regarding the interpretation of certain LCP provisions in the 2006 Act. We have identified three specific issues which may require a legal interpretation:

- application of LCP provisions to the residual supply for SOS procured from conventional resources,
- application of LCP provisions to supply services other than SOS, and
- application of a cost-effectiveness screening to diverse resources and DR.

We discuss each of these issues briefly below. Obtaining definitive answers regarding the application of the 2006 Act to each of these issues will likely require a legal interpretation, which is beyond the scope of this report.

The LCP provisions of the 2006 Act begin by indicating that the LCP and supply procurement, as "…complementary but distinct activities," have as a common purpose meeting electrical needs in a manner that is "…optimally cost-effective, reliable, prudent and environmentally responsible." This statement raises the question as to whether standards for cost-effectiveness, reliability, prudence, and environmental responsibility are to be applied to the supply procurement component of the portfolio.

The second question is whether the LCP provisions of the 2006 Act apply to supply services other than SOS. This arises from views expressed by some parties that the intent of the legislation was to meet the electrical needs of all customers in Rhode Island, including customers purchasing Last Resort Service and those purchasing supply from competitive suppliers. However, the LCP provisions do not include an explicit definition identifying the entities to which they apply, unlike the RES legislation which has an explicit definition stating that it applies to all entities selling electrical energy to end-use customers.[22] Instead, the LCP provisions simply require EDUs to file plans "…for system reliability and energy efficiency and conservation procurement."[23] In addition, the 2006 Act modifies the SOS cost recovery provisions[24] to allow EDUs to include their costs for "…system reliability, procurement and least cost procurement, as provided for in RIGL 39-1-27.7." Since those are the only sections of the 2006 Act that address LCP filings and cost recovery, it appears that the LCP provisions only apply to SOS.

Finally, in its description of the resources included in system reliability procurement, the 2006 Act explicitly identifies DG that is "...cost-effective with measurable, net system benefits." In contrast, that section[25] does not impose an explicit cost effectiveness requirement on diverse sources or DR. From a policy perspective one could interpret this to mean that individual diverse and DR resources should not be dropped from consideration for inclusion in a candidate portfolio based upon a preliminary screening for cost-effectiveness on a stand-alone basis, but instead the entire candidate portfolio should be evaluated for cost-effectiveness. On the other

[22] RIGL 39-26-1
[23] RIGL 39-1-27.7(c)(4)
[24] RIGL 39-1-27.3 (b)
[25] RIGL 39-1-27.7 (a) 1

hand, the absence of a reference to cost-effectiveness in the definitions of these two resources could simply be an oversight.

B. Cost-Effectiveness Standard

The PUC will have to establish standards for each of the LCP criteria mentioned in the 2006 Act, i.e., cost-effective, reliable, prudent, environmentally responsible. This section explains why we expect most of the debate to focus upon establishment of the standards for environmental responsibility and cost-effectiveness. It also explains why, even with these standards, parties will still likely need to exercise judgment in the selection of the optimal portfolio.

The 2006 Act requires the selection of a portfolio of efficiency, system reliability and conventional supply resources that will meet the electrical needs of the state's customers in a manner that is "…optimally *cost-effective, reliable, prudent and environmentally responsible*". In order to implement that aspect of the Act, the PUC will have to establish standards for each of those criteria. Each standard is likely to be a minimum, or threshold, level that must be achieved.

We expect that most of the debate regarding establishment of these standards to focus on the definitions of "environmentally responsible" and "cost-effective" rather than "reliability" and "prudence." Reliability in electricity supply is typically measured in terms of a "loss of load probability" (LOLP), with well established quantitative methods. This, while subject to some uncertainty, will likely be the easiest criterion to apply as it can be expressed quantitatively and supported by empirical evidence from installations of the prospective resource in other settings. Prudence is a relatively well-established concept in utility regulation. It essentially is a measure of the quality of the supporting data and assumptions.

In contrast to reliability and prudence, the choice of a standard to measure "environmentally responsible" may prove to be controversial. If parties desire a broad standard, a problem may arise due to the absence of a common unit in which to express a wide range of diverse environmental impacts. For example, what single unit would one use to measure and compare the environmental impacts of nuclear generation, coal generation, natural gas generation and wind generation? A second problem is that cap and trade programs for various air emissions, such as NOx, SO2, and now GHG, internalize some - but not all - of the environmental costs of those emissions. That aspect could be addressed by identifying the dominant environmental impact of electricity consumption in Rhode Island over the study period whose internalized cost[26] most significantly understates the total value of its environmental impact supported by current science, and then developing the appropriate externality values for that parameter. Carbon dioxide emissions are a likely candidate[27].

Ultimately we expect that any disagreement over this criterion will likely be closely related, either explicitly or implicitly, to the cost-effective criteria. In other words, parties who oppose use of a broad measure of environmental responsibility will likely do so over concerns that such a measure will ultimately be used to justify the acquisition of resources they consider to be "high

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[26] Internalized costs, such as a carbon tax, are being considered in cost analyses whereas externality values are not.
[27] Synapse is currently preparing such an analysis as part of its estimation of avoided energy supply components for a group of New England electric and gas utilities.

cost." That debate could be avoided if the PUC were to select the Societal Cost Test as the standard for cost-effectiveness. That test includes externalities, as well as direct costs, in the comparison of benefits and costs.

Parties in Rhode Island can draw upon their experience with various tests for cost-effectiveness to establish a standard. That experience includes the application of a market test to evaluate the cost-effectiveness of supply procurement and a utility cost test to evaluate the cost-effectiveness of energy efficiency programs.

- Currently utilities in Rhode Island effectively measure the cost-effectiveness of their LRS service supply portfolio over a relatively short time period, e.g., 1 to 3 years, using market price as the reference point or benchmark. They accomplish this in two ways. First, they acquire supply under contracts of relatively short duration through an auction. This ensures that they are paying the "market price" for the energy product they are purchasing. Second, they periodically review market trends to determine whether they should be acquiring a different set of products (i.e., contracts of longer duration). Their contracts for SOS supply consist of a fixed base price and an adjustment for changes in fuel prices. This adjustment results in prices that are close to prices in the wholesale market. Thus, the measure of cost effectiveness of supply is expressed in terms of the cost of purchased energy (cents/kwh).
- Rhode Island utilities currently measure the cost-effectiveness of energy efficiency programs using a formal test that compares the estimated benefits of the energy saved over the life of the efficiency measure, some of which have lives ranging from 10 to 20 years or more, to the costs incurred by the utility. Under this utility cost test, cost effectiveness is expressed in terms of a benefit/cost ratio, rather than in terms of the cost of saved energy (cents/kwh). The program costs are known with relative certainty but the benefits (projected savings in energy costs, capacity costs, and costs of related resources) are subject to uncertainty in terms of underlying energy prices. The utilities do attempt to estimate the market prices of energy and capacity, as well as the margins for uncertainty built into the bid prices submitted in auctions, but the resulting estimates are still subject to uncertainty.

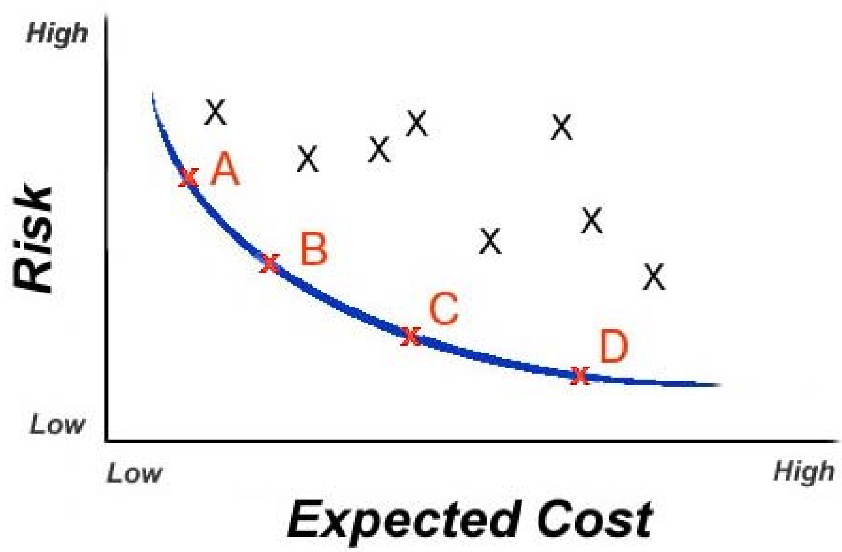
The major potential source of disagreement regarding the application of a cost effectiveness test under an LCP approach is the evaluation time-frame and amount of money at stake. Under the current approach utilities are accustomed to evaluating DSM programs over long time-frames, but the quantity of energy and amount of money at stake is relatively modest. They are also accustomed to committing to spend large amounts to acquire conventional supply over periods ranging from a few months to a few years. However, within that timeframe the utilities can draw upon market expectations reflected in futures prices and the risk of unexpected changes in customer load is relatively small. In contrast, under an LCP approach, utilities may be facing decisions to acquire much larger quantities of capacity and energy, e.g., contracts for wind resources equal to 10% of annual supply over periods of 10 to 20 years. The cost risks associated with those decisions are much greater because of the amounts involved and the uncertainties regarding customer loads and resource prices in the long-term.

An example of this type of disagreement occurred recently in Delaware. In response to an RFP for a 25 year power supply contract, Delmarva received three bids. One bid was from a proposed coal-fired IGCC, one from a gas-fired combined cycle, and one from a proposed offshore wind farm. Both Delmarva and an independent consultant retained by the Delaware Public Service Commission (PSC) evaluated the three bids over the 25 years relative to the projected costs of continuing to purchase "market supply." They performed this evaluation for several different scenarios, or sets of alternative assumptions regarding the future. The results for every scenario show continuation of purchases at market price to have the lowest levelized cost.[28] At least two of the bidders disagreed with the results and attributed those results to incorrect assumptions.[29]

A few states, such as California and Iowa, have established metrics and procedures for addressing this uncertainty quantitatively. They use probability distributions to calculate the range of costs for each potential portfolio. For each candidate portfolio they plot expected cost and a measure of cost risk, for example high cost at a 95% confidence level. They can use those results to understand any major trade-offs involved, in particular the magnitude of the uncertainty in costs, and then to make informed decisions.[30] Delmarva, and its regulator the Delaware PSC, are facing the need to make such a trade-off in choosing between the bids received for long-term power supply.

Below we present an illustration of a scenario in which a decision-maker wishes to choose a portfolio than minimizes both expected cost and expected cost risk from a set of candidate portfolios. All of the portfolios satisfy the non-cost other criteria, e.g., reliability, prudence, and environmental responsibility. Each of the portfolios labeled A, B, C, and D represent the best combination of expected cost and cost risk, and therefore are preferable to those plotted as an "X" on the chart. Out of those four eligible portfolios the decision-maker must select the one that has the most acceptable balance of expected cost and cost risk.

Figure 4 - Illustrative Trade-off of Expected Cost and Cost Risk



[28] For example $85/MWh (2005$) or 8.5 cents/kwh in the Reference Case scenarios relative to estimates of 8.6 cents/kwh to 10.7 cents/kwh for the various long-term contracts.
[29] Argus Air Daily, *Delaware bidders call foul*, March 9, 2007.
[30] Steinhurst, William et al., *Portfolio Management: Tools and Practices for Regulators,* Synapse Energy Economics, September 2006

The need for parties to exercise judgment in the selection of the optimal portfolio could also arise in a scenario in which there were several candidate portfolios that each met, or exceeded, the minimum levels for reliability, prudence, environmental responsibility, and cost-effectiveness. For example assume that Portfolio A, when compared to portfolio B, has a higher level of cost-effectiveness and lower level of environmental responsibility. In order to choose the optimal portfolio in that scenario, the EDU, the PUC, and intervenors must make a trade-off between higher cost-effectiveness (portfolio A) and higher environmental responsibility (portfolio B).

Some of the concern regarding tests for cost-effectiveness applied over long time periods is, not surprisingly, associated with the question of who will bear the financial consequences if the forecasts of performance and/or prices underlying the decision/selection prove to be dramatically wrong. This is the stranded cost issue, which we will address next.

C. Risk of stranded cost

Utilities may react to any discussion of LCP standards that require reliance upon long-term commitments for resources with a concern about their exposure to stranded costs. The basic concern here is that retail customers on SOS are not “captive” to that service. Instead, they have the option to migrate to supply service offered by competitive suppliers. Thus, the utilities providing SOS may be opposed to long-term resource commitments such as a long-term wind contract for fear of a scenario in which their SOS becomes uncompetitive, customers migrate, and the utility is left with no ability to recover the costs it is incurring under its long-term commitments.

These concerns should be acknowledged, and during the process of developing LCP standards they should be addressed in a just and reasonable manner. It will be useful to complete a quantitative analysis to place these concerns in context. Is there a possibility that customers will migrate immediately in mass, leaving the utility with sudden significant stranded costs, or is it likely that there will be modest migration over time? If there is modest migration and only minor levels of stranded costs, the utility could recover them from its remaining customers via the “true-up” component of its SOS tariff. That adjustment enables the utilities to recover any under-recoveries (or refund any over-recoveries). There are other possible ways to enable a utility to recover reasonable costs if it experiences customer migration. For example, California has established a policy under which its utilities will be able to recover the cost of certain mandated investments and acquisitions via a recovery charge (cents/kwh) to be applied to all throughput (all kwh) regardless of the customer’s source of supply. That approach eliminates the utility’s exposure to stranded costs as a result of customer migration.

Utilities are also concerned about their potential exposure to “stranded” distribution costs as a result of significant reductions in customer consumption. This concern arises because utilities will see a decline in revenue for distribution service as customers reduce consumption, but may not be able to avoid certain distribution costs they incur to provide that service. Thus, they could incur “stranded distribution costs,” and hence lower earnings, until their distribution rates can be reset in their next general rate proceeding. Decoupling of distribution service revenues from customer energy consumption is an option for addressing this impact that is receiving considerable attention. Under a decoupling approach, rates for distribution service would be adjusted periodically, possibly annually, to enable the EDU to continue collecting its approved level of distribution service revenues despite the decline in customer energy consumption due to efficiency programs and/or distributed generation.

4. Developments Elsewhere

The dramatic increases in fuel prices over the last few years combined with the growing recognition of the need to reduce GHG has led numerous states within the United States and jurisdictions in other countries to place increased emphasis on lower cost and cleaner resources such as energy efficiency and renewables.

Within the United States these policy changes have occurred, and are occurring, both in states that currently allow retail competition and those that do not.[31] [32] The one theme we see repeated in most, if not all, of these dockets is the importance of pursuing a multitude of different resources – efficiency, demand response, renewables, and clean fossil-fired generation. There is no single resource that can meet all of the needs of retail customers, i.e., no silver bullet. Pursuant to this theme, states are evaluating various approaches to the designation of a portfolio manager to be responsible for evaluating, and acquiring, the appropriate mix of resources. In effect, this is what Rhode Island is doing through the 2006 Act; it is designating electric distribution utilities to be portfolio mangers responsible for meeting the needs of customers on SOS.

Among the states that currently do not allow retail competition, California and several of the Pacific Northwest states have been most active in encouraging greater use of efficiency and renewables as well as in requiring utilities to file multi-year integrated resource plans every few years. California has an explicit policy under its Energy Action Plan (EAP) that identifies cost-effective energy efficiency and demand response as the first means of meeting the State's energy needs, followed by renewables and distributed generation. The EAP requires California Utilities to evaluate energy efficiency under both a Total Resource Cost (TRC) test and a Program Administrator Cost (PAC) test.[33] Utilities must integrate programs that are cost-effective under both tests into their resource plans on an equal basis with supply-side resource options and 20% of retail supply to be provided from renewables by 2010. The EAP identifies clean, efficient fossil-fired generation as the source of supply for the residual needs not met by those preferred resources.[34]

However, even with its history of emphasizing efficiency and that loading order, California utilities are still projecting load growth and a significant level of dependence upon conventional generation. This reality is illustrated by the projection from a recent long-term procurement plan filing of a California IOU presented in Figure 5.

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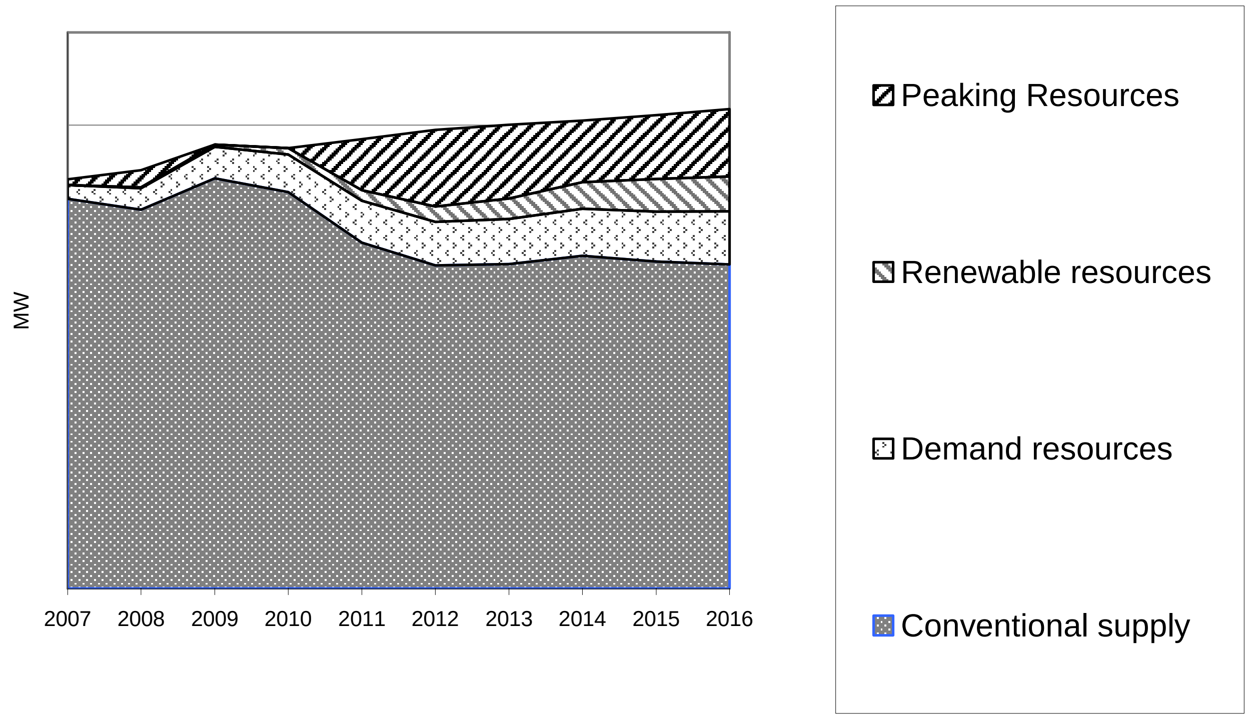
[31] Brockway, Nancy. *Delaware's Electricity Future: Re-Regulation Options and Impacts*. Prepared for Delaware Office of Management and Budget. May 2007.

[32] Resource Insight, Inc. and Synapse Energy Economics, Inc., *Integrated Portfolio Management In A Restructured Supply Market*, June 2006, www.synapse-energy.com

[33] In the TRC the value of energy savings is compared to the total cost of installed measures, including participant costs, and all program costs. In the PAC the value of energy savings is compared to the cost of utility financial incentives to customers and all other program costs.

[34] CPUC, INTERIM OPINION ENERGY EFFICIENCY PORTFOLIO PLANS AND PROGRAM FUNDING LEVELS FOR 2006-2008 – PHASE 1 ISSUES, Decision 05-09-043 September 22, 2005

Figure 5 - Example of Projected Load and Resource Mix of a CA IOU.



5. Potential options for LCP standards

Stakeholders have the opportunity to provide input into the OER's recommendations and ultimately into the PUC proceeding regarding regulations to implement LCP. This section identifies four areas in which the stakeholders may wish to provide input, and presents various options for consideration.

A. Energy Efficiency

A standard to encourage effective procurement of all energy efficiency resources costing less than additional electricity supply could have several elements. Following are options and issues that could be considered in developing such a standard. These options are not mutually exclusive, but some may have interactive effects that would need to be examined:

- Avoided Costs. Periodic determination of long-term avoided costs, including assessment of uncertainty associated with these estimates. Utilities in Rhode Island currently do this through a consortium of New England utilities that prepares such an estimate every two years. This estimate provides projections of avoided costs needed to evaluate the cost-effectiveness of efficiency measures.

- Cost-Effectiveness Test. Require EDUs to procure all energy efficiency that is cost-effective under the TRC test.

- Achievable Potential. Periodic determination of the maximum achievable cost-effective energy efficiency potential in their service territories. This type of estimate is needed as a guide to set targets and budgets, as well as to evaluate the utility's performance relative to the available efficiency resources.

- Annual Targets. Set annual targets for efficiency savings (e.g., additional 1% of kWh sales saved each year or 10% of maximum cost-effective potential each year). This type of explicit standard would be comparable to the RES standard.

- Maximum Energy Efficiency at Minimum Cost. Require the EDU to procure the maximum quantity of efficiency at minimum cost. This may entail evaluation and use of alternative procurement approaches including soliciting bids for energy efficiency and/or offering a standard energy efficiency offer, subject to strong anti-cream skimming provisions.[35] It could also entail the design of programs to ensure that once energy efficiency program services are being provided in a given building or facility, all cost effective measures will be delivered to that structure without arbitrary limits on service delivery. Finally, it could entail development of a multi-year process for efficiency planning and budgeting. This would promote comprehensive programs and process improvement that will maximize the quantity of efficiency acquired at minimum program administration costs.

- Align EDU Financial Incentives with Energy Eficiency. Evaluate the need for changes in the manner in which rates for distribution service are set in order to better align distribution utility financial incentives with maximum pursuit of energy efficiency. One option is to address the concern that distribution companies might suffer a material reduction in earnings if their customers reduce their electricity usage substantially in response to efficiency programs offered as part of SOS. This issue could also be addressed in connection with the treatment of stranded costs discussed below.

B. System Reliability Resources

A standard to support effective procurement of system reliability resources could have some of the types of elements discussed under the energy efficiency standard, in particular avoided costs, achievable potential, and alignment of EDU financial incentives. In addition, the standard could consider the following option.

- Procurement to Achieve an Optimal Portfolio. Require the EDU to procure the quantity of system reliability resources needed to achieve an optimal portfolio for SOS. This may

[35] Under energy efficiency bidding one establishes a block of supply requirements (MW, MWh, time frame) and solicits bids for energy efficiency services to fill the block subject to a maximum price equal to the avoided cost. Under a standard offer one publishes a schedule of payments that will be made for verified efficiency savings and uses a standard form contract with durations of various lengths (e.g., 5 or 10 years) and payments based on avoided costs.

entail evaluation and use of alternative procurement approaches including contracting for a portion of renewables and/or DG under long term contracts, such as 10 years or life of unit. The appropriate quantity of and contracting approach to system reliability resources could be issues for periodic re-determination in the triennial LCP filings in order to reflect changes in SOS requirements and market conditions, including the market for renewable energy and distributed generation.

C. Optimal Resource Mix

Develop standards for cost-effectiveness and environmental responsibility to be used in the determination of whether a candidate portfolio is optimal.

The standard for cost-effectiveness might include one or more of the following components:

- Cost-Effectiveness Test. Require EDUs to estimate the expected cost of each candidate portfolio to SOS customers over a common, long-term planning horizon.

- Cost Risk. A requirement that evaluation of resources under consideration for the SOS portfolio include an estimate of the cost risk of each resource over a long-term planning horizon. Alternatively, the standard could require the projections of traditional supply resource prices to include an adjustment or adder to reflect the incremental cost risk associated with those resources relative to efficiency, demand response, and renewables, due to their exposure to commodity price volatility and future greenhouse gas emission costs for example. A third alternative would be to require risk-adjusted discounting. By requiring EDUs to consider the cost risk of each resource, this standard would contribute to a more accurate comparison of energy efficiency, system reliability, and conventional supply resources.

- Long Term Planning Horizon. A requirement that selection of resources for the SOS portfolio be based upon the present value of their costs over a long-term planning horizon, e.g., 20 years. Requiring the costs of each resource to be evaluated over the same multi-year planning horizon will enable a more equal comparison and should reveal differences that would be difficult to identify otherwise, such as relative magnitude of cost risk associated with each resource.

The standard for environmental responsibility might include one or more of the following components:

- All Environmental Externalities. Require EDUs to estimate the environmental externalities associated with each resource in their proposed portfolio. The analyses of resource costs will necessarily already include the costs of complying with various air emission regulations. This requirement would require EDUs to consider the costs of externalities associated with each resource that are not captured in projected electricity market prices.

- Dominant Environmental Externality. Require EDUs to estimate the dominant environmental externality associated with their proposed portfolio. The dominant externality could be the environmental impact of electricity consumption in Rhode Island (or the world) over the study period whose internalized cost most significantly understates the total value of its environmental impact, e.g., CO_2 emissions.

D. Potential Stranded Costs

Consideration of the potential for stranded costs as a result of an LCP approach should include definitions of the types of costs that could potentially become "stranded" and an examination of the circumstances under which this could occur. It would also be informative to estimate threshold levels of such costs as well as any offsetting benefits. Under the current SOS tariff it is not clear that the distribution companies would be exposed to any stranded SOS service costs since they are allowed to recover the actual costs they incur to provide this service. This is accomplished through an annual adjustment or "true-up" which is set to either recover the prior year's under-recovery or return the prior-year's over-recovery. The continued operation of this annual true-up should be included in the discussion of any standard regarding stranded costs. If the distribution company will not be exposed to stranded costs due to the rate true-up, parties may wish to examine measures to limit the exposure of customers who remain on SOS to costs that are "stranded" due to the migration of customers from SOS to competitive suppliers.

6. Conclusions

The LCP portion of the 2006 statute, in conjunction with the RES, provides Rhode Island with a policy framework and approach for meeting the electrical needs of its citizens at lower costs, and with lower environmental impacts, than would otherwise occur. These reductions will result from using system reliability resources and efficiency resources to displace a corresponding quantity of supply from conventional generation.

The Stakeholders have the opportunity to provide input into the OER's recommendations and ultimately into the PUC proceeding regarding regulations to implement LCP. They should consider providing input in the following four areas:

- a standard that will support effective procurement of all energy efficiency resources costing less than additional electricity supply;
- a standard regarding contractual approaches for procurement of renewable energy resources;
- standards for "cost-effective" and "environmentally responsible" to be used in the determination of whether a candidate portfolio is "optimal;" and
- the treatment of potential stranded costs as a result of an LCP approach.

The combined impact of these standards will be to help achieve the goal of pursuing a multitude of different resources – efficiency, demand response, renewables, and clean generation.

ATTACHMENT 1 - IMPLICATIONS OF NOT IMPLEMENTING RES AND LCP

With no changes in existing policies, Rhode Island is facing a continued high dependence on natural gas for electric generation, high electricity supply prices, and high levels of carbon dioxide (CO_2) and other emissions from the sources procured to serve Rhode Island. This outlook is based upon projections for New England drawn from the Reference Case of Annual Energy Outlook 2007 (AEO 2007) prepared by the Energy Information Administration (EIA) and released in January 2007. The Reference Case assumes no carbon regulation.

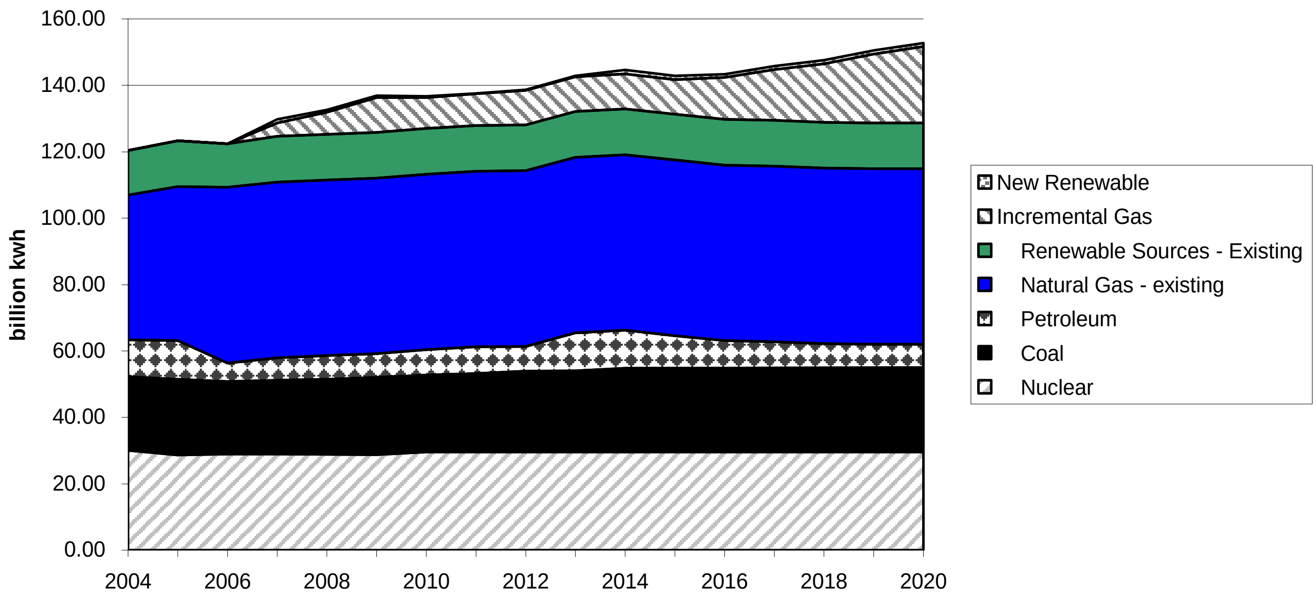
Continued high dependence on natural gas for electric generation

The supply for SOS and LRS has been, and will likely continue to be, procured at prices tied to the wholesale market operated by ISO New England. That market consists of several markets for electric power products including energy, operating reserves,[36] and capacity. ISO NE sets the market price of electric energy by zone in each hour at the locational marginal price (LMP). The LMP at a given location reflects the bid submitted by the last, or marginal, unit. ISO NE pays all generators in that zone that are dispatched in that hour the LMP, regardless of their actual operating costs. The marginal units in many zones in New England in most hours have been, and are expected to continue to be, natural gas fired generation with relatively high variable production costs. Thus it is a wholesale market dominated by gas-fired generation in which prices are based upon marginal costs of production.

In 2005 approximately 40 percent of the electricity consumed in New England, including Rhode Island, was generated from natural gas. As indicated under the Reference Case in Figure A-1, the EIA is projecting that dependence on natural gas to increase to 50 percent by 2020. That level of dependence on a single, relatively high cost fuel raises a host of concerns regarding security of supply, high average prices, and volatile prices.

[36] Regulation, spinning, ten-minute non-spinning, thirty minute non-spinning.

Figure A - 1
Projection of Generation by Fuel in New England - AEO 2007 Reference Case

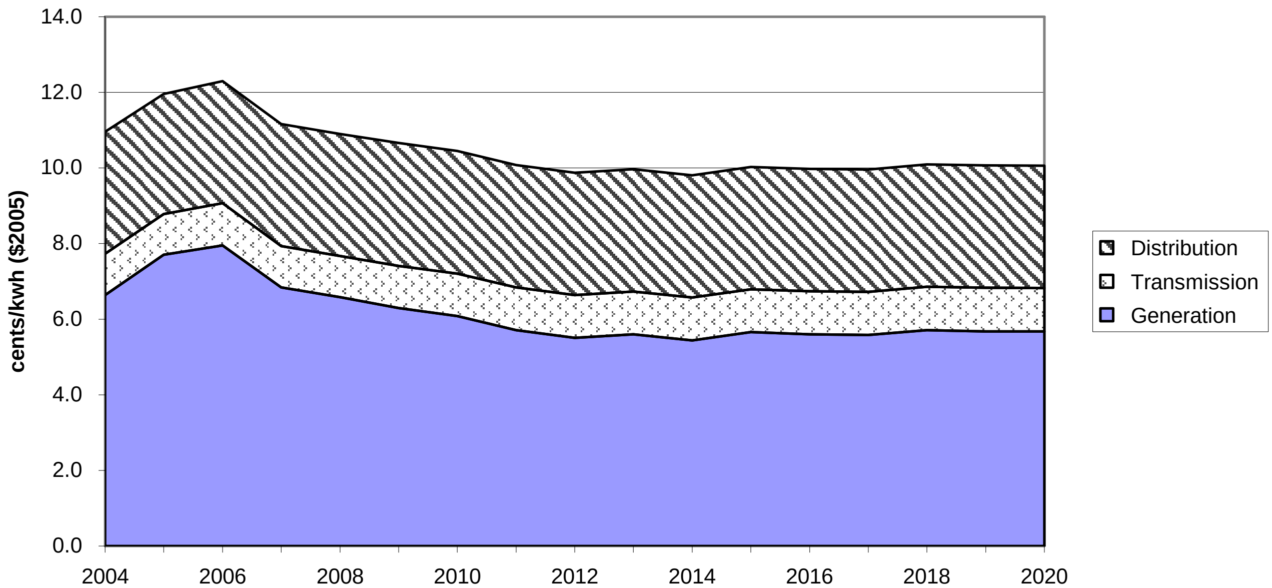


Continued high electricity supply prices

In 2005 the total average price of electricity to all customer classes in New England was 12 cents/kwh. Of that total, 7.7 cents or 64% was the price of generation. (The average total price in Rhode Island in 2005 was 11.7 cents/kwh, with the average price of NGRID SOS service at 7.1 cents/kwh)[37]. As indicated under the Reference Case in Figure A-2, the EIA is projecting that total average price to decline to approximately 10 cents/kwh ($2005) based upon the EIA's projection that the average generation costs will decline to 5.7 cents.

[37] Energy Information Administration, *State Energy Profiles 2005*, page 200 and *Summary of National Grid's Standard Offer and Last Resort Rates*, http://www.ripuc.org/utilityinfo/electric/narrelecschedule.html.

Figure A-2
Projection of Average Electricity Price in New England by Component - AEO 2007 Reference Case



It is important to note that there is considerable uncertainty associated with the EIA projection that the average generation price in New England will decline to 5.7 cents, and hence with its forecast decline in average electricity prices to 10 cents/kwh. First, the EIA projection for generation prices does not assume any regulation of carbon, and hence no costs of carbon emissions. However, we know that their will be costs for carbon emissions in New England starting in 2009 under the Regional Greenhouse Gas Initiative (RGGI). It also appears highly likely that some form of federal regulation of carbon emissions will eventually replace RGGI. Second, the EIA projection is heavily dependent upon its projection of natural gas prices. Based upon past experience, it is certainly possible that the actual prices of natural gas may be higher than the EIA forecast, and hence electricity prices would be higher accordingly.

In this regard it is interesting to note that the Electric Power Research Institute (EPRI) is projecting the price for generation delivered into the grid from most new clean technologies to be in the order of 7 cents/kwh, assuming a gas price of $6/MMBtu and carbon prices in the order of $10/ton.[38] This includes generation from wind, nuclear and clean-coal technologies. That estimate is consistent with recent bids for generation under long-term contracts received by the Delaware PSC, which were in the range of 8.7 cents/kwh to 10 cents/kwh.

A third point to note is that hourly prices in the wholesale market for electric energy have, and will continue to, exhibit the same volatility as natural gas prices in the daily spot market. The close connection between hourly electric energy prices and natural gas prices in the daily spot market is due to the fact that high price gas-fired and oil-fired generation is on the margin, and

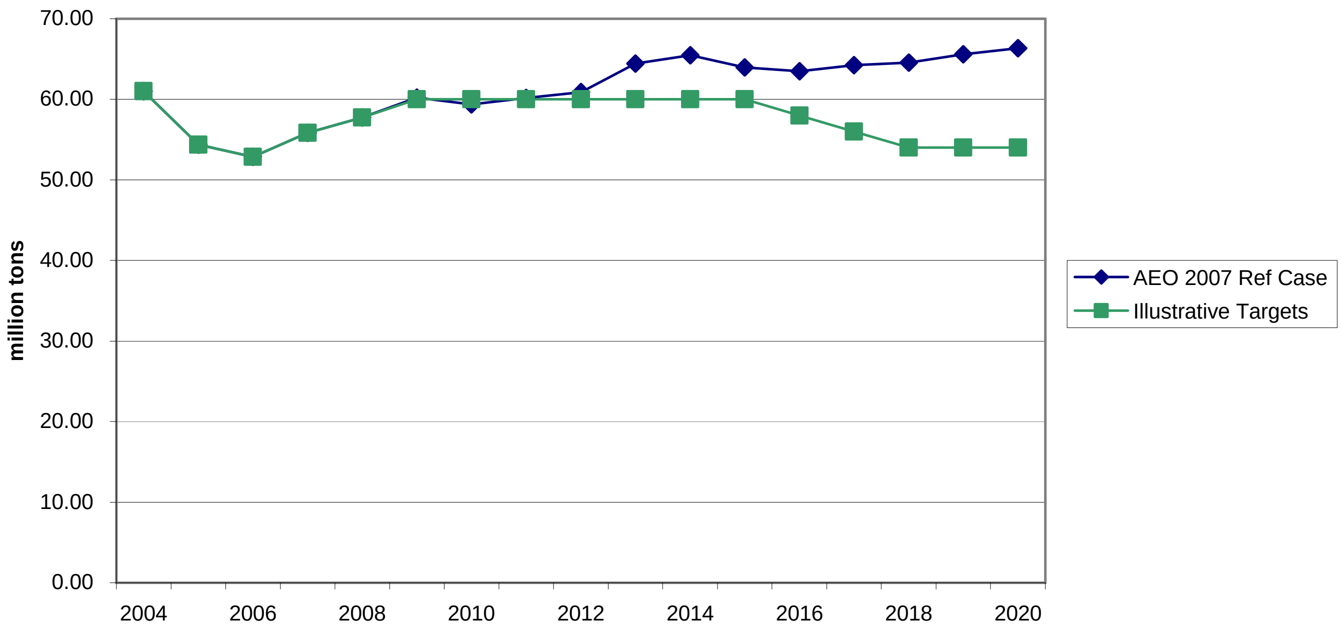
[38] Specker, Steven. *Electricity Technology in a Carbon-Constrained Future.* Electric Power Research Institute. February, 2007.

hence essentially determines, the wholesale electric energy market price in most hours. For example, in 2005 gas and oil-fired units set the market price in the vast majority of the hours.[39]

Continued high levels of CO2 and other emissions

In 2005 the generation of electricity in New England resulted in emissions of approximately 54 million tons of carbon dioxide. As indicated under the Reference Case in Figure A-3, the EIA is projecting emissions of 66 million tons by 2020, an increase of about 20%. In contrast, the goals under the Regional Greenhouse Gas Initiative (RGGI) include stabilization of emissions at current levels from 2009 through 2015 followed by a 10% reduction by 2019.

Figure A-3
Projection of Carbon Emissions in New England vs RGGI Goals



Rhode Island has put in place enough initiatives from the GHG process, including LCP, to offset all projected GHG growth in Rhode Island, but to meet the New England Governor's targets of 10% below 1990 levels by 2020 and then 75-80% eventually (e.g., by 2050) will require successful implementation of LCP and other yet-to-be-specified additional policies.

[39] ISO New England, *State of the Market Report 2005*, page 6