Draft White Paper

Least Cost Electricity Procurement for Standard Offer Service in Rhode Island

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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 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 system reliability resources (e.g., diverse sources, including renewable energy resources, distributed generation, demand response) and efficiency resources and 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 have little or no ability to influence the first two categories of factors, but they do 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 standards for "cost-effectiveness" and "environmentally responsible" to be used in the determination of whether a particular portfolio is "optimal";

- the standard regarding contractual approaches for procurement of renewable energy resources;
- the treatment of potential stranded costs, including defining what constitutes potential future stranded costs, what level of exposure to potential future stranded costs is justified by the benefits anticipated under LCP, and an appropriate disposition of any such stranded costs taking into account the offsetting benefits. and
- 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"). 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". It requires them to broaden the set of resources they use to provide that service to include two new categories of resources, "system reliability" and "energy efficiency", in addition to "supply" resources, and extends the date through which electric distribution companies are required to provide standard power supply service (standard offer or SOS) to 2020.

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. Electric distribution utilities in RI have been acquiring supply from conventional resources since the inception of SOS in 1997, as part of the restructuring of the state's electric market to explicitly separate the supply function from the distribution function, and to allow retail customers to shop for their supply. Retail customers who did not choose a competitive supplier were placed on "Standard Offer" service. Retail customers who left SOS, and subsequently were not being served by a competitive supplier, were placed on Last Resort Service (LRS). Their 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 majority of small volume customers in the residential, commercial and industrial classes remain on either SOS or LRS.

Energy efficiency resources are also not new. Rhode Island utilities have been providing energy efficiency, or "demand side management" programs for many years funded by a charge capped at 0.2 cents/kwh paid by all ratepayers, they collects about $20 million a year. What is new is the increased emphasis the Act places on energy efficiency, by recognizing it as a resource on a par with supply resources. The Act specifies that LCP shall include energy efficiency resources that are prudent, reliable, and lower cost than additional supply. Thus, the LCP provides the opportunity to eliminate that cap on funding of energy efficiency programs and thereby enable utilities to procure all cost-effective energy efficiency.

The Act identifies system reliability as an explicit new category of resources. It indicates that they include supply from diverse resources, including renewable resources, distributed generation (DG) and demand response (DR). Of those three resources, the only one limited to an explicit requirement to be "cost-effective" is DG. The Act does not specify that LCP is explicitly linked to 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 reasonable to assume that LCP contemplates 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 of the Rhode Island Greenhouse Gas (GHG) Process 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 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.

This draft has been prepared for discussion at the April 26 meeting of the Stakeholders. It presents the issues associated with implementing LCP in four sections:

- implications of implementing LCP ;
- issues associated with the implementation of LCP;
- developments in other states; and
- conclusions.

2. Implications of implementing LCP

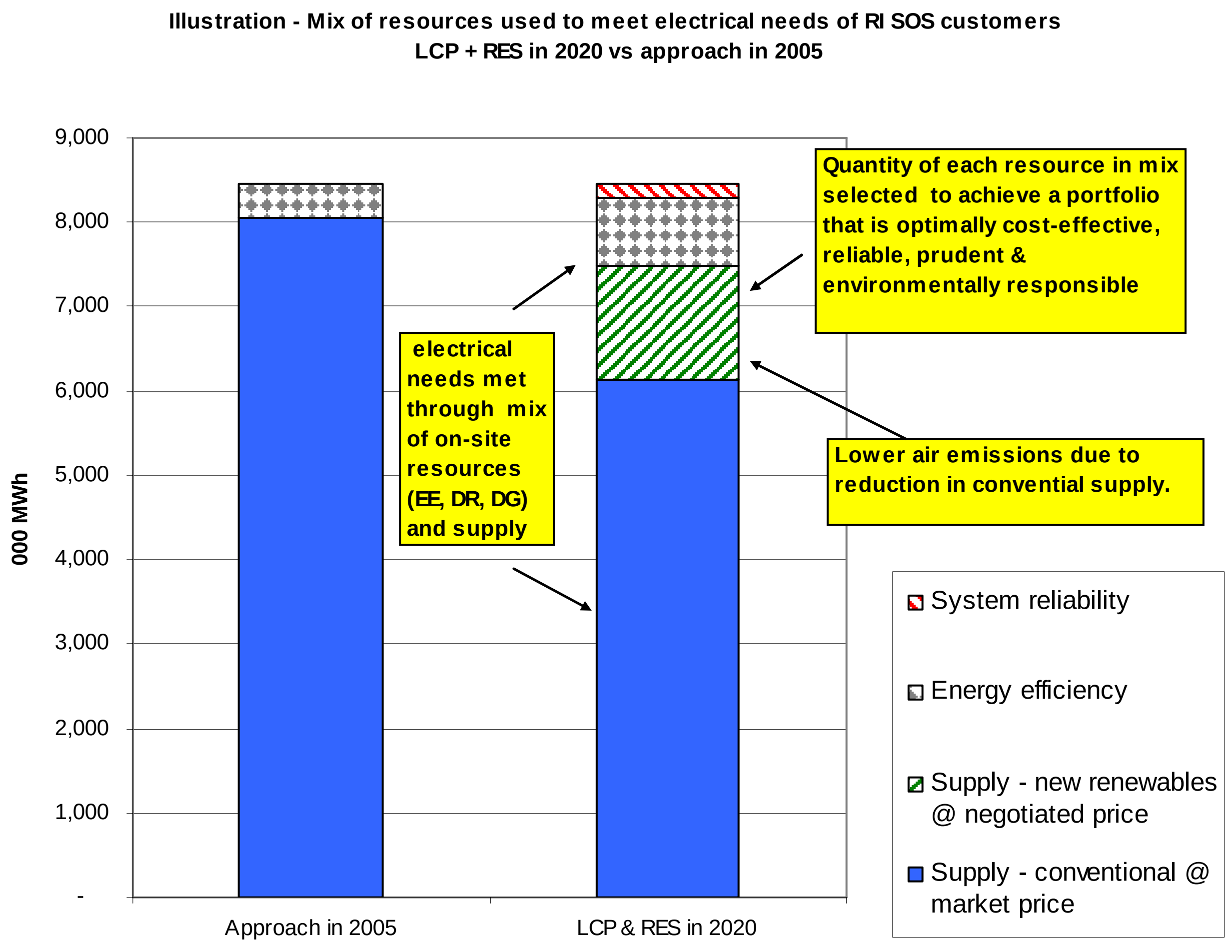
This section identifies the potential implications of implementing LCP through an illustrative example. The example compares the mix of resources used to meet the electrical needs of RI retail customers in 2005 with a possible mix to meeting the same level of needs in 2020 under an LCP approach

The 2006 Act requires electric distribution companies to go beyond conventional supply resources and renewables under the RES to formally consider, and include, system reliability and energy efficiency resources to the portfolio they use to meet the needs of their SOS customers. What will this really mean in practice? For example, what quantity of each resource will the distribution utility select and on what basis? How different will the utility's portfolio, and the bills of SOS customers, look as compared to those under the policies to date?

This section uses an illustrative example, presented in Figure 1, to identify several of the major implications of an LCP approach as compared to the approach in place prior to 2007. The example uses recent data for Rhode Island, primarily from 2005, and makes a number of assumptions to develop a LCP and RES scenario for 2020 to meet the same total level of electrical needs. The assumptions, while within the realm of possibility, are simply to illustrate the differences between the two approaches. This figure illustrates that, relative to the mix in 2005, one could expect the mix under a LCP approach in 2020 to consist of:

- a portion from system reliability resources;
- a significantly increased portion from energy efficiency resources;
- renewable energy at, or in excess of, the RES target of 16 %; and
- conventional supply accounting for the remaining, lower portion.

Figure 1



A. Optimal Mix

The first major implication of an LCP approach is that electric distribution companies will have to develop a portfolio from a broader range of resources rather than purchasing an undifferentiated mix of full-requirements supply. For this example we assume that the electric companies select a combination of energy efficiency resources and system reliability resources. The latter category may include use of renewable energy resources, with or without renewable energy credits (RECs), in addition to and separate from the renewable resources they acquire to satisfy the RES requirements. Use of those resources reduces the portion of customer needs they meet by conventional supply. In our illustration we assume that 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.) It is important that LCP treat the role of generation from renewable resources separately from the acquisition of RECs, for which there are specific targets which can be met either as part of a portfolio (with energy and RECs purchased together) or distinct.

Flowing directly from this assumed mix is a key question for all parties, and ultimately for the PUC, i.e., on what basis will the distribution utility and its customers choose the quantity of each resource? The utility is required to select a portfolio that is "…optimally cost-effective, reliable, prudent and environmentally responsible". However, the utility does not have complete control over the relative quantity of each resource ultimately selected. Customers will have a direct input regarding the quantities of system reliability and efficiency resources, since those resources are installed on, and operated from, customer sites. The utility will exercise some influence on customer acceptance and use of these resources, through price signals and program design for example, but does not have complete control over the number of installations.

The PUC, through the standards it sets under the 2006 Act, will establish the specific criteria for utilities to apply when evaluating each resource and developing their portfolio. The standards should address the contractual terms through which utilities acquire these resources, in particular pricing provisions and contract duration. These standards may be particularly relevant to the two system reliability resources, diverse resources and DR, for which the Act does not explicitly require a test for cost effectiveness.

B. Energy Efficiency

The second major implication of an LCP approach is that electric distribution companies may find it cost-effective to meet a much higher percentage of the electrical needs of their customers using energy efficiency. Various studies indicate that electrical needs met through efficiency cost about 3 cents/kwh, which is 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.[12]

However, increasing the portion of needs met through energy efficiency will likely require an increase in the charge used to fund those programs. Currently that charge is 2 mills (0.2 cents/kwh). Utilities also collect a charge to fund renewables programs. It is currently set at .3 mills.

As indicated in Figure 1, in 2005 the portion of electrical needs of RI customers met by energy efficiency was in the order of 5% to 6%, or 400,000 MWh. This is an estimate of the cumulative impact of efficiency programs implemented in prior years[3]. The aggregate contribution from efficiency has been limited by various factors, including constraints on ratepayer funding of energy efficiency programs. RI distribution companies provide energy efficiency using funds

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[1] Massachusetts Division of Energy Resources *Massachusetts Saving Energy*, , April 2, 2007,
[2] 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
[3] 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

collected from ratepayers. The PUC limits the annual budgets for these programs. For example, the PUC has approved an annual budget for NGRID[4] in 2007 of $ 22.5 million, which is funded by a charge of 0.2 cents/kwh that NGRID collects on the kwh consumed by every customer, i.e. both those who participate in its programs and those who do not. NGRID expects that these programs will produce annual savings of 62,600 MWh. By comparison, RI electric distribution companies acquired 8,000,000 MWh of conventional supply to meet the consumption portion of electrical needs in 2005.

C. Renewable Energy

A third major implication of an LCP approach, in conjunction with the RES, is that electric distribution companies will be procuring a significant quantity of renewable energy. One of the key questions in this regard is the contractual arrangements through which utilities should acquire these resources.

Utilities in Rhode Island, and elsewhere in New England, have to acquire supply to meet the needs of SOS customers, and have to meet a portion of that supply with renewable energy. In RI this is governed by the RES[5]. 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” (REC). Thus, a utility might pay 8.0 cents/kwh[6] for the energy and over 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.[7] 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 which can be considered as part of a LCP.

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

[4] NGRID delivers the vast majority of the electricity consumed in the state.
[5] In other states the comparable standard is referred to as a Renewable Portfolio Standard (RPS).
[6] 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.
[7] On April 18, 2007 the OER released a study, RIWINDS, evaluating the feasibility of one or more major wind farms off RI, including alternative methods of financing such a project.

The first two options are alternative strategies for RES compliance.[8] 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 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 purchasing energy from renewable generation under long-term contracts is cost-effective.

D. Impact on customer bills

One of the primary goals of 2006 Act is to meet the electrical needs of customers at lower expected costs than would they otherwise incur. The illustration of alternative portfolios that could be used to meet those electrical needs, presented in Figure 1, says nothing about the costs that customers would see on their average bill under each approach. Determining an answer to how the average bills of customers will change under LCP will obviously be one of the primary goals of the upcoming PUC proceeding to establish standards for implementation of the 2006 Act. However, in order to inform the debate regarding the potential role of system reliability, energy efficiency and supply resources under LCP we have prepared an illustrative estimate of the impact on an average bill of alternative portfolios by making various assumptions about the costs of resources presented in the illustration 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. Thus, any such analysis needs to be presented in terms of a high probability of achieving lower costs than would be experienced in the absence of LCP.

One illustration based upon a set of mix and cost assumption is presented in Table 1.

[8] 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."

Table 1 – Illustrative Monthly Bills for SOS[9]			
utility rate for resource (cents/kwh)	**Approach in 2005**	**LCP & RES in 2020 Scenario A Supply renewable @ 7 cents/kwh**	**LCP & RES in 2020 Scenario B supply renewable @ 9 cents/kwh**
System Reliability @ 0.2	0 %	2 %	2 %
Efficiency @ 0.2	5 %		
Efficiency @ 0.4		10 %	10 %
Supply – Renewable		16 %	16 %
Supply – Conventional @ 7.7	95 %	72 %	72 %
Monthly bill (average of all customer classes)	$108	$ 99	$104
Air emissions index[10]	100	76	76

Again, the values in Table 1 are simply for illustrative purposes. Development of accurate estimates will require substantial analysis, and will depend upon a host of factors, including the portions of monthly electrical needs actually met from each resource and the actual utility charges for each resource. The point is that this type of analysis will help place the impacts of the various resources on average bills into perspective, for various assumptions of percentage of mix, and utility charge, by resource. (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. It is also important to capture in the calculation, or failing that to acknowledge, any differences in the certainty of the underlying estimates of prices and costs. Without these efforts to ensure comparability of estimates for each portfolio one will not have an apples-to-apples comparison. 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 of for energy savings or generation, such as wind, with more certain costs.

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

3. Setting standards for the implementation of LCP

This section discusses the issues most likely to be the subject of dispute during the process of setting those standards. While there will likely be various issues on which parties have conflicting views, we expect that they will all ultimately relate to treatment of uncertainty in the standard for cost-effectiveness, and or the risk of stranded cost.

A. The standard for cost-effectiveness applicable to selection of a reasonable 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 a standard for determining whether a particular portfolio of resources is "optimal". Such a determination typically involves judgment, and may entail a trade-off between the various criteria. For example, a resource may be reliable but not cost-effective. Alternatively a resource may be cost-effective but not environmentally responsible. Nevertheless, we expect the debate to ultimately focus upon the application of the test for cost-effectiveness for two reasons. First, the tests for reliability, prudence and environmentally responsible will all eventually lead to a proposed portfolio whose ultimate test will be one of its cost-effectiveness. Second, the inputs to any calculation of cost-effectiveness to be made over a future long-term period are uncertain. However, the level of debate over this issue will be influenced by the approach taken regarding the risk of stranded cost.

We expect that the tests for reliability, prudence and environmentally responsible will eventually lead to a proposed portfolio whose ultimate test will be one of its cost-effectiveness for the following reasons.

- 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.
- 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[11] 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[12].

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 environmentally responsible 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 cost".

The PUC and Rhode Island utilities do have experience with various tests of cost-effectiveness that could be, and will likely be, used as standards for LCP. However, it is possible that problems will arise with the application of these tests given the time-frames and dollar amounts involved.

- 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 over the life of a given measure, some of which have lives ranging from 10 to 20 years or more. The measure of cost effectiveness of efficiency 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. This concern is most likely to arise when a prospective resource is being evaluated over many years, for example 5 years to 25 years or longer. In the three to five year timeframe parties can draw upon market expectations reflected in futures prices while beyond that timeframe there is general agreement regarding the uncertainty associated with forecasts of demand, supply and price.

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[11] Internalized costs, such as a carbon tax, are being considered in cost analyses whereas externality values are not.
[12] 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.

However, in an LCP approach these decisions may involve acquisition of much larger quantities, e.g. contracts for wind resources equal to 10% of annual supply, over periods of 10 to 20 years. Utilities are accustomed to evaluating DSM programs over that time-frame, but for much smaller quantities, less than 1 % of their annual supply for example.

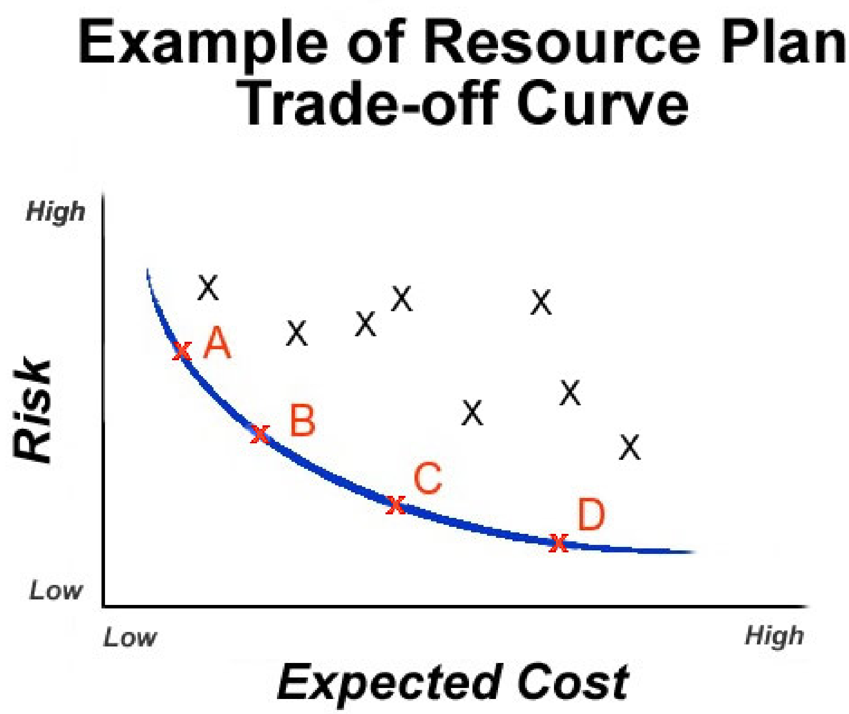
An example of this type of disagreement occurred recently in Delaware. In response to an RFP for a 25 year power supply contract, Delmarva received three bids. One bid was from a proposed coal-fired IGCC, one from a gas-fired combined cycle and one from a proposed offshore wind farm. Both Delmarva and 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 did 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 ($/MWh in 2005$), for example $85/MWh 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. At least two of the bidders disagreed with the results and attributed those results to incorrect assumptions.[13]

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.[14] 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.

[13] Argus Air Daily, *Delaware bidders call foul*, March 9, 2007.
[14] Steinhurst, William et al., *Portfolio Management: Tools and Practices for Regulators,* Synapse Energy Economics, , September 2006

Figure 2 - Illustrative Trade-off of Expected Cost and Cost Risk



In theory this evaluation and selection problem can be solved by formulating it as an "optimization" problem via a computer program. Under this approach the computer software is told to find the portfolio of resources that will meet the specified reliability standard at minimum cost and minimum environmental impact. In practice, computer modeling can provide input to the selection process but the various parties need to understand the nature and magnitude of the trade-offs involved in order to make an informed decision.

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.

B. 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, a long-term wind contract for example, for fear of a scenario in which their SOS becoming uncompetitive, customers migrating, and the utility being left with no ability to recover 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 of the distribution costs they incur to provide that service. Thus, could incur "stranded distribution costs", and hence lower earnings, until their distribution rates can be reset in their next general rate proceeding. Decoupling of revenues from consumption is an option for addressing this impact that is receiving considerable attention.

4. Developments in Other States

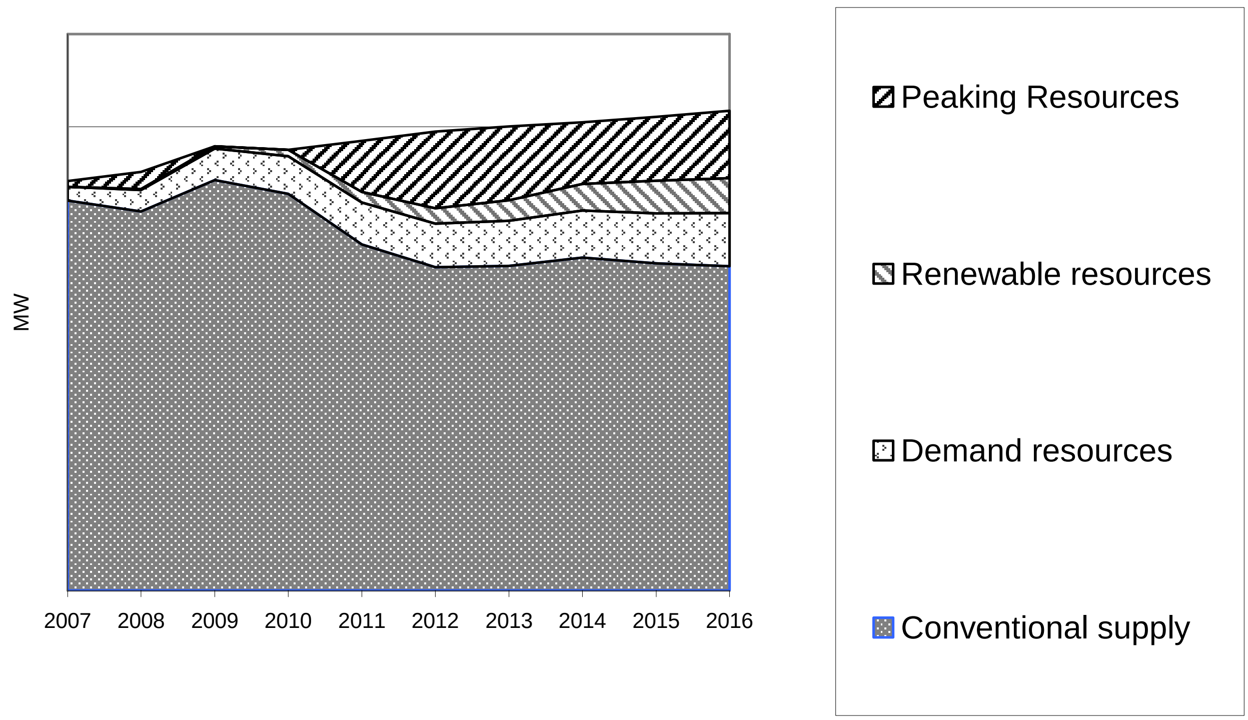
Rhode Island is not the only jurisdiction pursuing changes in the policy framework governing the approach used to meet the electrical energy needs of retail customers. The dramatic increases in fuel prices over the last few years, combined with the growing recognition of the need to reduce GHG, has led numerous states within the U.S. and jurisdictions in other countries to place increased emphasis on lower cost and cleaner resources such as energy efficiency and renewables.

Within the U.S. these policy changes have occurred, and are occurring, both in states that currently allow retail competition and those that do not. 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.

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. In fact, 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 all cost-effective[15] energy efficiency to be integrated into utilities' resource plans on an equal basis with supply-side resource options; and that 20% of retail supply 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.[16]

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 2.

Figure 3 - Example of Projected Load and Resource Mix of a CA IOU.



5. Conclusions and next steps

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

[15] Total Resource Cost Test, including estimated avoided costs for generation, transmission and distribution costs, and environmental externalities.

[16] CPUC, *Energy Action Plan II: Implementation Roadmap for Energy Policies.* 2005

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.
The stakeholders should consider providing input regarding several aspects of those standards. These include:

- a standard that will support effective procurement of all energy efficiency resources costing less than additional electricity supply”
- the standard to be used to measure "environmentally responsible"
- the approach to be used to address uncertainty when determining the cost-effectiveness of candidate portfolios;
- the standard regarding contractual approaches for procurement of renewable energy resources;
- the potential for utilities providing SOS to incur stranded costs as a result of an LCP approach, including defining what constitutes potential future stranded costs, what level of exposure to potential future stranded costs id justified by the benefits anticipated under LCP, and an appropriate disposition of any such stranded costs taking into account the offsetting benefits.
- 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.

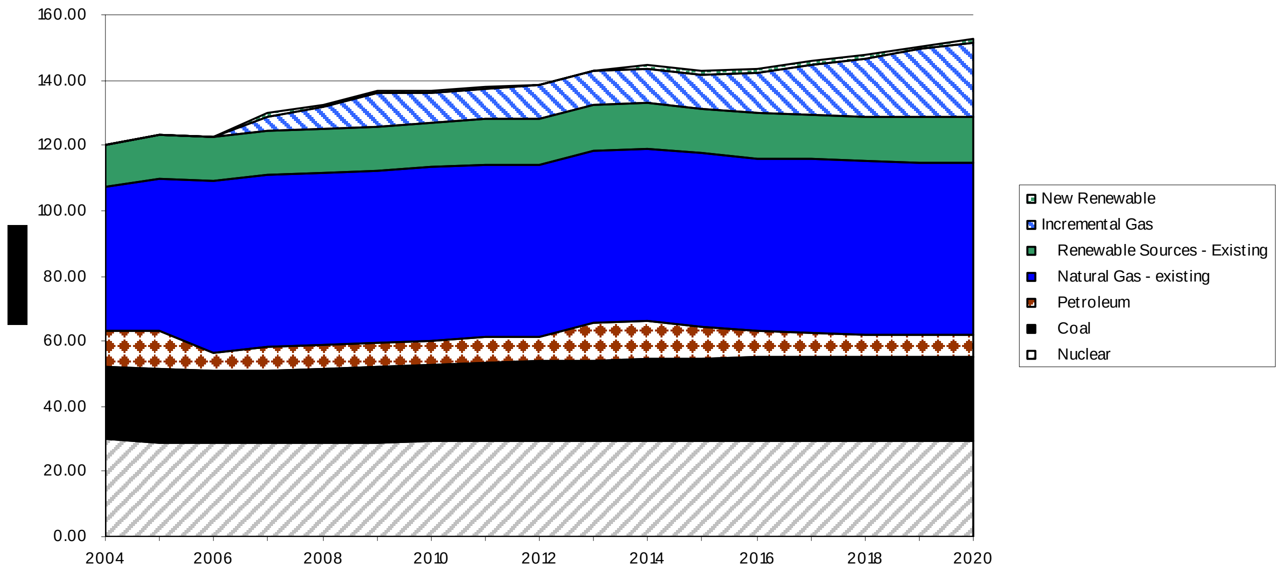
A. Continued high dependence on natural gas for electric generation

Currently all of the supply for SOS is being acquired under short-term contracts from bidders who in turn acquire it from the wholesale market operated by ISO New England. That market consists of several markets for electric power products including energy, operating reserves[17] 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 in Figure A-1, under its Reference Case the EIA is projecting that dependence 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.

[17] 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

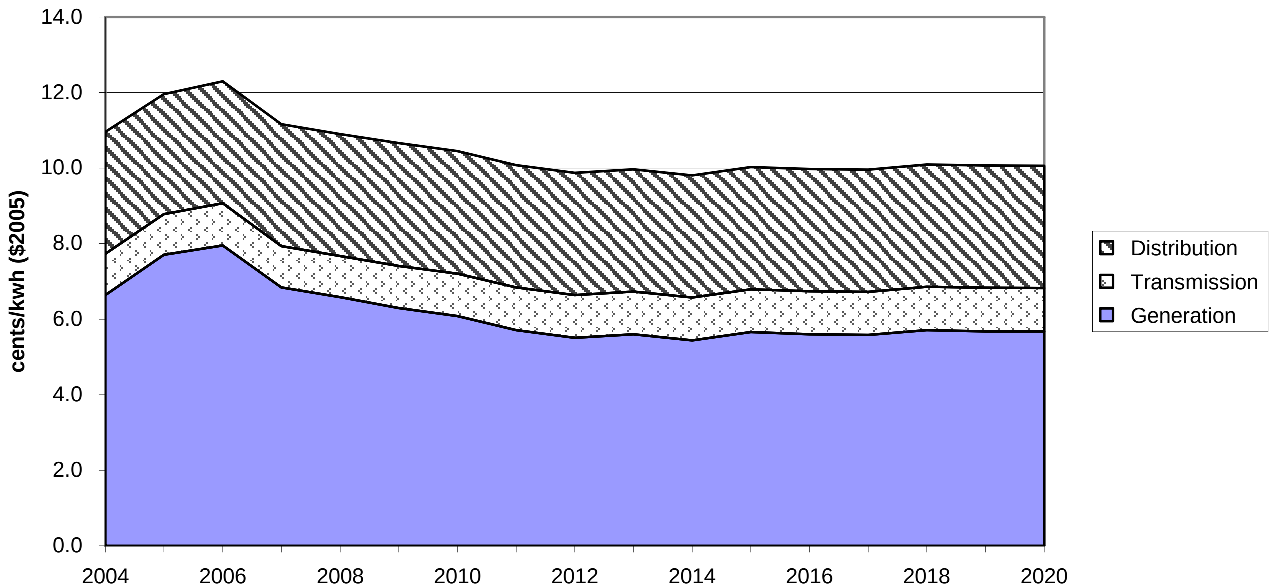


B. Continued high electricity supply prices

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)[18]. As indicated in Figure A-2, under its Reference Case 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.

[18] Energy Information Administration, *State Energy Profiles 2005*, page 200 and *Summary of National Grid's Standard Offer and Last Resort Rates*, www.ripuc.org/utility info.

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 that 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.[19] 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

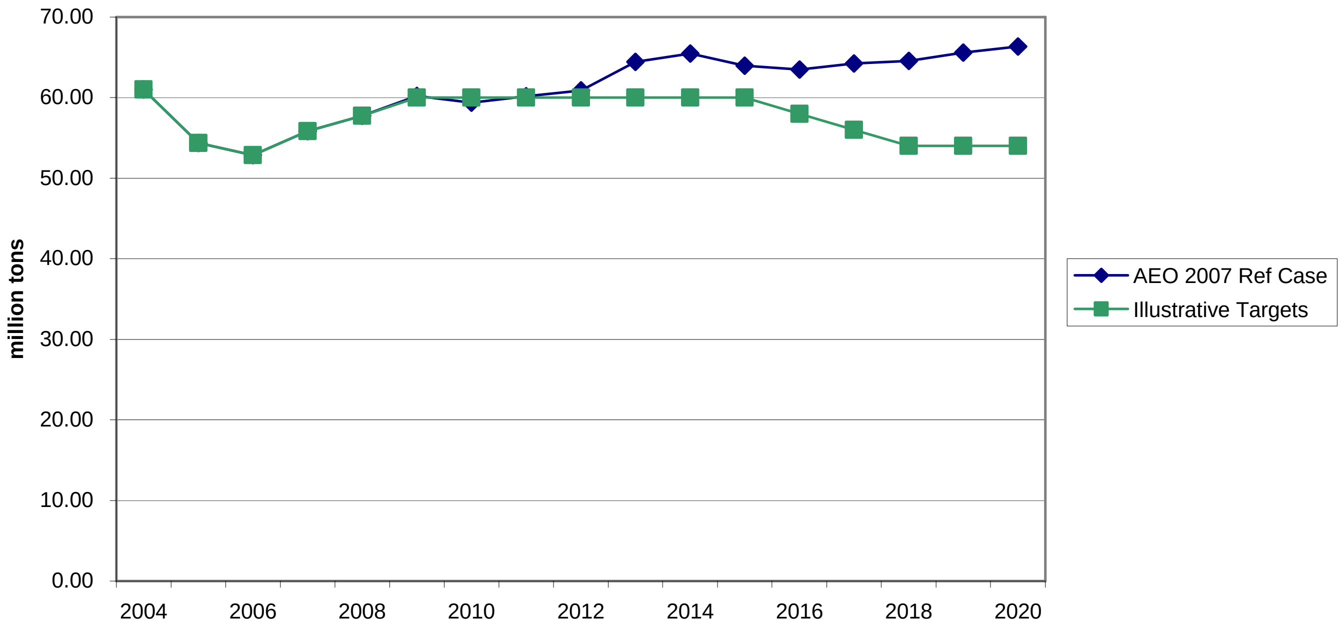
[19] Specker, Steven. *Electricity Technology in a Carbon-Constrained Future.* Electric Power Research Institute. February, 2007.

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.[20]

C. Continued high levels of CO_2 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 in Figure A-3, under its Reference Case 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 imitative (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



RI has put in place enough initiatives from the GHG process, including LCP, to offset all projected GHG growth in RI, 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.

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