Synapse
Energy Economics, Inc.

Comments Regarding Integrated Resource Plan for Connecticut Energy Advisory Board Prepared by Connecticut Light & Power, United Illuminating Company, and the Brattle Group

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EXECUTIVE SUMMARY

Connecticut Integrated Resources Plan (IRP): Prepared by Connecticut Light & Power, United Illuminating Company and the Brattle Group for submission to the Connecticut Energy Advisory Board, dated January 1, 2008, pursuant to Section 51 of Public Act 07-242 (Act). AARP retained Synapse Energy Economics (Synapse) to review that IRP. This report presents our comments resulting from that review.

Public Act 07-242 (Act), Section 51, requires Connecticut's electric distribution companies (Companies) to prepare a "comprehensive plan for the procurement of energy resources" and to submit a plan to the Connecticut Energy Advisory Board by January 1, 2008, and annually thereafter. The intent of the legislation was to require the Companies to emphasize the use of energy efficiency to meet the service requirements of their customers, through a comprehensive integrated resource strategy. Section 51c requires that all resource needs be first met through cost-effective energy efficiency and demand reduction measures. This provision provides significant opportunities for the distribution companies to build upon the success of Connecticut's existing energy efficiency program. The Act was passed while the effects of several factors were being experienced at the same time:

- Connecticut's electricity rates rose to be among the highest in the US,
- The state is exposed to fuel price volatility from continued reliance on fossil-fueled generating resources,
- Natural gas generating resources set the marginal hourly clearing price in the region's electricity market, and
- The state's participation in a regional greenhouse gas reduction program created uncertainty about potential rate impacts.

These factors are expected to continue to impact future decisions related to Connecticut's energy supply and demand.

The submitted IRP does not take advantage of the strong legislative message and requirements of Section 51. Its four recommendations are general and the IRP itself does not provide the specific framework and detail required by the language or intent of Section 51. The IRP contains several significant gaps that need to be addressed in order to comply with Section 51. These comments discuss those gaps under five major headings General Areas of Non-Compliance, Demand Side Management, Power Procurement Structures, Renewable Portfolio Standards and Exposure to Natural Gas Prices and Availability. The comments are summarized below and discussed in the subsequent sections.

General Areas of Non-Compliance

- Fails to develop a plan that would enable Reliability Must Run (RMR) units to be retired, saving ratepayers over $140 million annually, and creating opportunities to construct more efficient generation
- No consideration of environmental regulations that will constrain the development of new generation resources

- No analysis of combined heat and power (CHP)
- No consideration of reducing energy requirements through cost effective improvements to the transmission and distribution system
- Fails to develop a comprehensive strategy based upon all cost-effective DSM plus new renewables and then new conventional generation
- No analysis of funding mechanisms that could be implemented to achieve the objectives of section 51. Ratepayers will be concerned about paying more for DSM, and there is additional concern about the need for government incentives for measures that are highly cost effective even without incentive.

Demand Side Management

- Fails to propose specific approaches to procurement of incremental DSM
- No analysis of potential funding mechanisms for demand side management, particularly energy efficiency, which could achieve the intent of the legislature, including private sector and innovative financing schemes that would complement the existing ratepayer funded programs and minimize the cost burden to ratepayers.
- No analysis of the benefits and costs of incremental demand response to be achieved through time-differentiated pricing supported by AMI. The absence of any such analysis is of major concern because there are significant concerns regarding the rate impacts, bill impacts and cost-effectiveness of mandatory time differentiated pricing supported by AMI.

Power Procurement Structures

- Fails to propose a new approach to acquiring supply for standard offer service (SOS) that would be preferable to the existing approach in terms of expected price and price stability over time through the inclusion of some long-term contracts and/or generation ownership.
- Fails to propose a benchmark, standard or test to guide the determination of the prudence of a new approach, and hence whether the costs that result from that approach are "just and reasonable" and eligible for recovery in rates.

Renewable Portfolio Standards

- Does not evaluate the extent to which generation needs can be met by renewable facilities, and therefore fails to comply with Section 51 (d).
- Does not compare the estimated levelized cost of the electricity from renewable resources over time to the estimated levelized cost of electricity from natural gas, coal and nuclear resources over time, including the cost of compliance with anticipated CO2 regulation.
- Fails to state that the Round 2 request for proposals (RFP) under Project 100 was limited to facilities located in Connecticut.

Exposure to Natural Gas Prices and Availability

- The IRP should have addressed the cost and risk associated with the exposure of Connecticut consumers to the price and availability of natural gas as part of the development of a specific plan to comply with Section 51 (d)

1. General Areas of Non-Compliance

A. Requirements of Public Act 07-242

Section 51, subsection (b) contains six provisions requires the electric distribution companies to "submit to the Connecticut Energy Advisory Board an assessment of (1) the energy and capacity requirements of customers for the next three, five and ten years, (2) the manner of how best to eliminate growth in electric demand, (3) how best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods, (4) the impact of current and projected environmental standards, including, but not limited to, those related to greenhouse gas emissions and the federal Clean Air Act goals and how different resources could help achieve those standards and goals, (5) energy security and economic risks associated with potential energy resources, and (6) the estimated lifetime cost and availability of potential energy resources."

B. IRP Approach to Address Requirements

The IRP provides an analysis of the expected energy requirements for the next three, five and ten years using the Dayzer model. Four scenarios are evaluated, one reference ("current trends") and three possible future variations (IRP Appendix G).

IRP recommendation 1 recommends that DSM measures be maximized to reduce peak load and energy consumption. The IRP recommends pursuing an aggressive DSM program focusing on ramping up of existing programs currently being implemented by the distribution companies. The IRP estimates that no new additional generating resources will be required in Connecticut, but the Dayzer model forecasts construction of a new coal or nuclear plant to be operating in 2018. To eliminate load growth and to level demand by reducing peak growth and shifting it to off-peak periods, the IRP recommends that the state pursue an aggressive DSM program, largely based on ramping up of existing programs currently being implemented by the two distribution companies.

The IRP provides estimated cost and availability for new gas, coal, nuclear and certain renewable generating resources. In terms of environmental considerations, it focuses on the state's implementation of the Regional Greenhouse Gas Initiative (RGGI) and the possibility of Federal legislation to reduce greenhouse gases nationally.

C. General areas of non-compliance and gaps

There are several areas where the IRP does not satisfy the requirements of Section 51. Each of the following sections specify the IRP gaps and recommends ways for the final IRP to fulfill the statutory requirements.

1. Section 51 b (1): Energy and capacity requirements for the next three, five and ten years

The IRP includes an analysis using the Dayzer model of current and potential future energy and capacity requirements based on current trends and potential future scenarios. This analysis misses two significant issues that already affects Connecticut's energy and capacity requirements. Failure to address them head-on exposes Connecticut to continuing high costs and impedes the ability to provide for a more affordable and secure energy future. These two areas are to develop a comprehensive resource plan to meet the state's needs that does not rely on the continued operation of the RMR units and consideration of other environmental constraints.

Retiring RMR Units

Appendix A, pages A-4 to A-7, provides an analysis of the "reliability, must run" (RMR) units that operate in Connecticut. These units provide critical voltage support and peaking generation resources and are concentrated in the Southwest Connecticut load pocket. The table on page A-6 reflects that annual costs of RMR units exceed $140 million, borne by all Connecticut ratepayers.

A comprehensive plan to eliminate load growth in Connecticut, reducing peak demand and implementing measures that help to shift load from peak to off-peak would reduce and eliminate the need for the RMR units to operate. Closure of the RMR units would save ratepayers at least $140 million annually. Closure of the RMR units would also free up NOx allowances for use by new projects and provide an avenue for the generation queue shown on page A-5 to be constructed and operated.

Consideration of other environmental constraints

The IRP focuses on current and possible future climate legislation that could impact and provide opportunities for Connecticut's energy supplies (pages 5, 6, 7). While CO2 regulations are imminent in Connecticut (RGGI commences January 1, 2009), carbon constraints on generation are not expected to impact generators in state until after January 1, 2015, when the state's RGGI budget begins to decrease at a rate of 2.5% annually.[1]

By comparison, other environmental constraints exist today, and the affect of these constraints increases in the near future, amplifying the influence of RGGI. Connecticut is subject to the Ozone Transport Commission's and EPA's NOx budget program and is considered non-attainment for ozone. These programs impose specific NOx emissions budgets and require that any new source constructed obtain emissions offsets equal or greater to the amount of NOx emissions that are expected to be emitted annually by any proposed generating plant. The NOx program constraints have severely limited the ability for new large generating sources to be constructed, and have had a direct current and continuing effect on state energy and capacity requirements.

2. Section 51 b (2): How to best eliminate growth in electric demand

The IRP recommends maximizing the use of DSM programs, within practical and operational limits. The basis for recommendation #1 assumes a continuation of the existing DSM programs operated by the distribution companies. The IRP focuses on DSM and does not consider additional demand reductions that can be achieved from implementation and enforcement of improved building code standards, improved appliance standards and improvements to the transmission and distribution (T/D) system. Each of these areas, with the exception of T/D, can be achieved by regulation and do not require additional revenue or charges to ratepayers.

[1] See www.rggi.org for program description, state emissions budgets and supporting documentation

3. Section 51 b (3): How to Level Demand by Reducing Peak Growth and Shifting Demand to Off-Peak Periods

The IRP focuses on existing and ramped up versions of existing programs. Appendix D, at D-7, provides a brief mention of direct load control programs.

The section above provided extensive comments on the IRP's gaps in addressing how to eliminate load growth. Those arguments are also applicable to the IRP's gaps in how to reduce peak load growth and shifting demand to off-peak. We discuss the IRP's treatment of demand response in the next section.

4. Section 51 b (4): Impact of Current and Project Future Environmental Standards

The IRP's focus on CO2 and its absence of mentioning any other requirements are highlighted above under b(1). By connecting the pieces between existing NOx constraints, and their economic and energy impacts, the IRP could make a strong case for retiring the RMR units, and be consistent with the requirements of Section 51. The Federal Clean Air Interstate Rule (CAIR) will be implemented in two phases, 2009 and 2014. The first phase will not affect Connecticut since its current emissions requirements already meet CAIR levels. However, the second phase of CAIR will require emissions to be reduced by an additional estimated 20-25%. This decrease is likely to affect the operation of the older, less efficient generating units.

Water use for cooling at existing gas and nuclear plants can also limit resource availability. The IRP should evaluate these current and potential constraints.

5. Section 5a b (5): Energy Security and Economic Risks

Recommendation 4 of the IRP highlights Connecticut's reliance on natural gas for generation, and the state's exposure to risk from this fuel. The recommendation is general, "consider ways to mitigate exposure", and does not provide a plan for doing so, as required by Section 51.

Business as usual for Connecticut will continue to expose ratepayers to high electricity costs. Part of this is outside the state's ability to control- for example, ISO-NE market rules set the hourly clearing price based upon the last unit dispatched- but Section 51, its requirements, other sections of the same act and existing programs provide a solid foundation from which Connecticut can increase its energy security and reduce its economic risks. Its energy efficiency program is already achieving substantial progress and was rated #1 in the US in 2007 by ACEEE. The state's RPS includes requirements for a portion of the electricity demand to be satisfied through efficiency and CHP, one of the first in the US to do so. Auctioning of RGGI allowances will provide a substantial boost, at no additional state or ratepayer costs, for energy efficiency and renewable energy investments. These pieces are substantial building blocks, and the IRP enabling legislation was intended to assemble these blocks into a comprehensive, long-term plan that would provide for a secure and affordable energy future.

6. Section 51 b (6): Estimated lifetime cost and availability of potential energy resources

The IRP evaluates current trends and three possible future scenarios, and provides cost estimates for each. Average locational marginal prices are provided in Appendix A. Development of scenarios is provided in Appendix B. Generation supply characterization is provided in Appendix C and renewable generation estimates are provided in Appendix E. These evaluations are adequate for an initial evaluation, but they do not comply with Section 51's requirement for a comprehensive resource plan.

The IRP does not include DSM measures as an energy resource. ISO-NE has initiated its forward capacity market, where all resources are valued equally, creating substantial opportunities for DSM and demand response to participate and receive payments for their participation. Combined heat and power is another resource that is not evaluated by the IRP. The transmission and distribution system can also be a resource. Improvements in the efficiency of T/D can defer the need to construct new generation, avoid the need to operate expensive peaking generation and complement energy efficiency programs.

The IRP's assumptions that a new coal or nuclear plant will be constructed in Connecticut circa 2018 are unrealistic. Nuclear licensing applications would already have to have been submitted to appropriate regulatory agencies in order for such a plant to commence operation in this timeframe. For coal, the IRP evaluation does not appear to include the recent escalation of construction costs and fuel supply issues, both of which factors should be integrated into the resource costs evaluated for the IRP. Construction costs have increased significantly since 2004, and the combination of global competition and the decreased value of the US dollar make it likely that such costs will continue to escalate. With regards to coal supply, global competition is leading to fuel price increases. This trend is also expected to continue due to the pace of new coal plant construction in China, and the ability for US suppliers to take advantage of this demand by increasing prices both domestically and globally.

2. Demand Side Management (IRP recommendation 1)

A. Energy Efficiency

Section 51c specifies that "resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible. The projected customer cost impact of any demand-side resources considered pursuant to this subsection shall be reviewed on an equitable bases with non demand-side resources…". The IRP recommends that the state "maximize the use of DSM, within practical operational and economic limits" largely through continuation and ramping up of the existing DSM programs. The IRP does not address:

- how resource needs shall first be met through all available energy efficiency and demand reduction resources, including the importance of new approaches to DSM to assure the most cost-effective acquisition of resources

- existing and potential future funding mechanisms, including evaluation of mechanisms that would complement current ratepayer funded programs
- how energy demand can be reduced through improvements in building codes and appliance standards;
- the importance of parity between ratepayer contributions and benefits for each sector

The first point is the most important, since it is a requirement of Section 51. Several studies completed in the last three years have estimated the potential for DSM in Connecticut and New England, their costs and their ability to offset load growth. DSM has two chief benefits as compared to other potential resources:

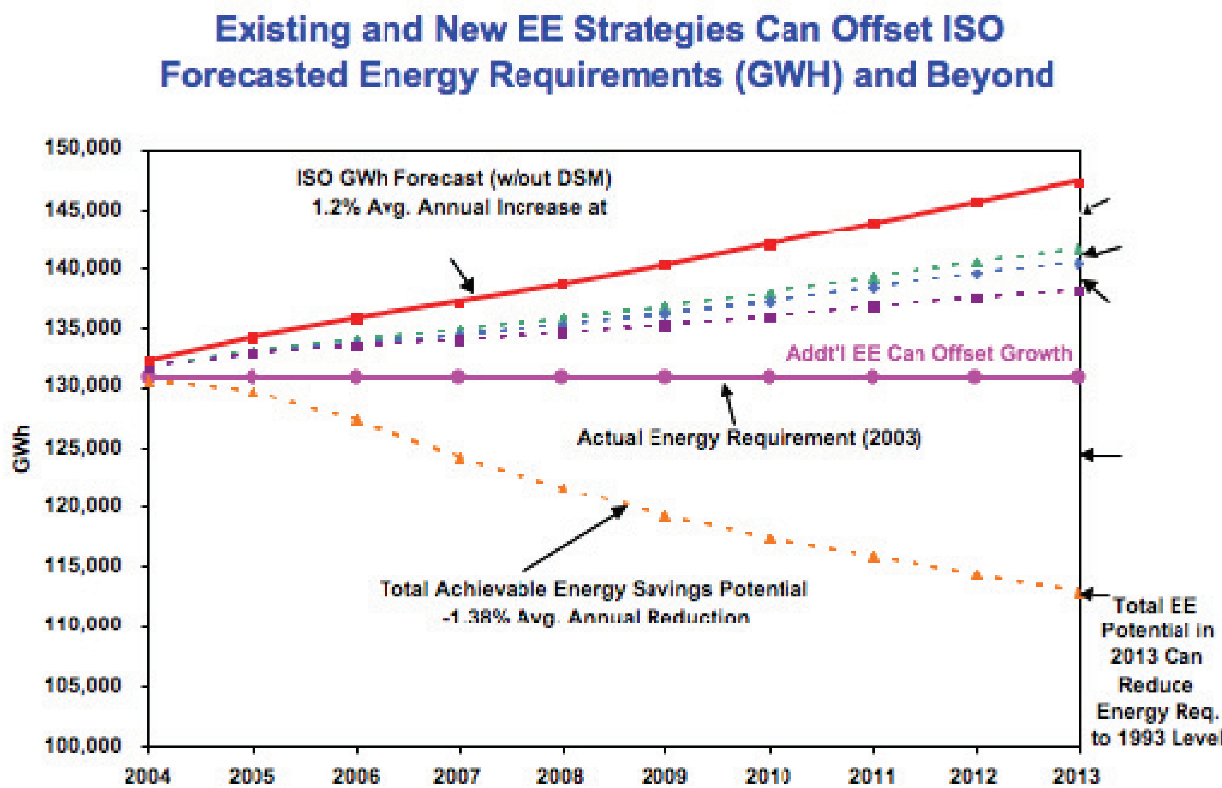
- its cost is lower than the cost of new generation and upgrades to the transmission system, and
- the resource benefits accumulate over time.

A NEEP report,[2] completed in 2004 and updated in 2005, provides an example of what can be technically achieved in Connecticut and the region through DSM. A report on the resource potential of energy efficiency in New England, completed by the Regulatory Assistance Project,[3] included the following analysis of the NEEP report:

> "The NEEP report forecasts that *economically achievable energy efficiency could bring New England's energy demand down to 1993 levels by 2013.* These savings, of over 33,000 GWh in 2013, would be achieved through a combination of increased investment in efficiency programs, using a variety of policy instruments, as well as improved standards and codes. See the figure below. At the time the study was updated, it was determined that continuing existing efficiency programs would capture only 20% of the efficiency potential by 2013. Notice also that there is no diminishing return involved with a very significant increase in energy efficiency procurement."

[2] Northeast Energy Efficiency Partnerships, "Economically Achievable Energy Efficiency Potential in New England", updated May 2005. Prepared by Optimal Energy.

[3] Regulatory Assistance Project, "Energy Efficiency in New England, Resource Opportunities", April 27, 2007.



Connecticut's Energy Conservation Management Board has also conducted studies of energy efficiency potential and completed an analysis to demonstrate how energy efficiency measures could offset all electric demand growth in the state as early as 2010. A maximum achievable potential study was completed in June 2004.[4] This study found that Connecticut could eliminate load growth cost-effectively for the period 2004 through 2013, reducing peak demand 13%, and electric demand by an equivalent amount. The net present value of these energy efficiency measures was estimated to save Connecticut ratepayers almost $1.8 billion.

The August 8, 2007 meeting of the ECMB discussed several possible scenarios to achieve the objectives of Section 51.[5] The slide below provides a description of these scenarios and their estimated energy benefits. The dark triangle in the middle of the slide is a reference to the 2004 GDS study discussed above, representing the expected level of peak demand if the recommended actions contained in that study were fully implemented.

The red line at the top represents the rate of demand increase without any efficiency programs. The blue line represents the progress being achieved by the current ECMB program, plus revenue received from the forward capacity market. Current programs are offsetting about 50 MW/year of the state's peak load growth. Lines below the blue line show

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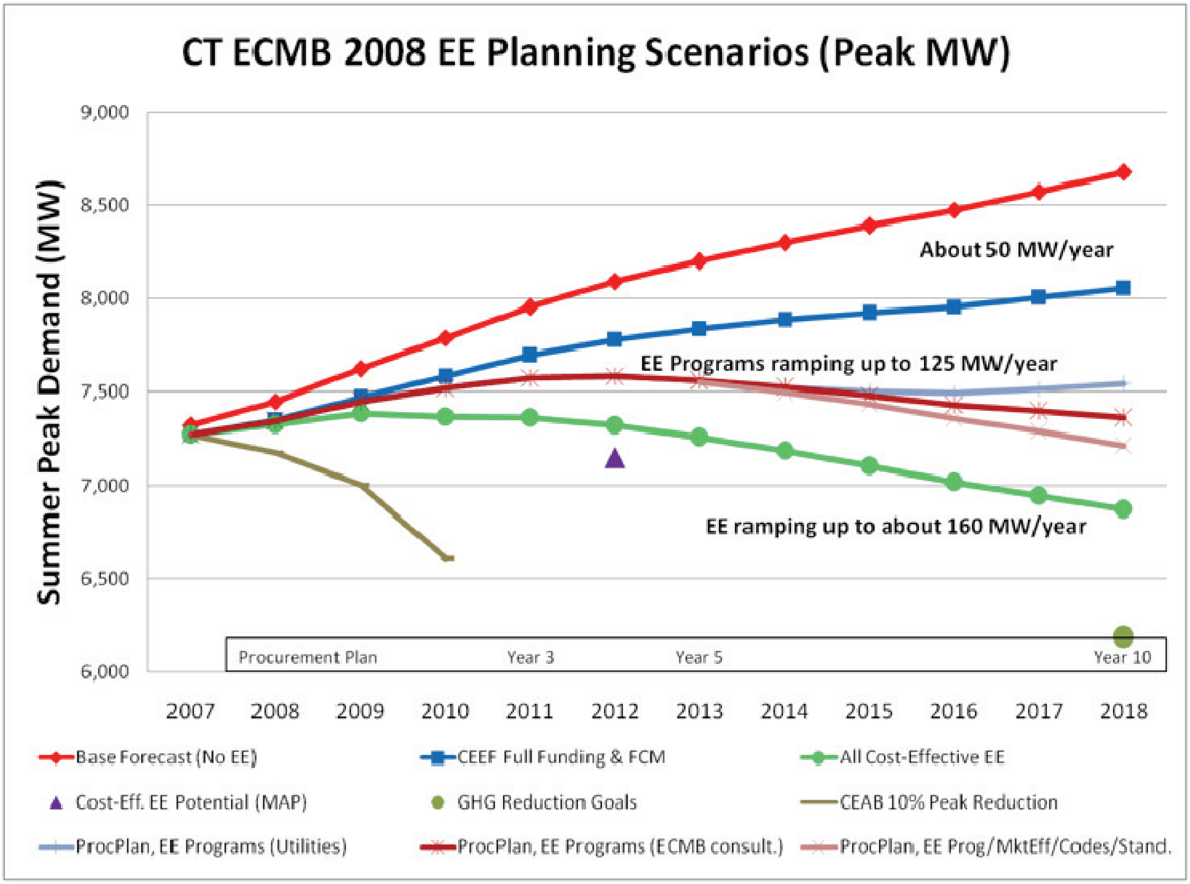
[4] GDS Associates, "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Region", June 2004.

[5] http://www.ctsavesenergy.org/ecmb/documents.php?section=14

increasing levels of efficiency, cumulating in the green line, which represents the rate of all cost-effective energy efficiency, reducing peak demand by about 160 MW per year.



Another section of PA 07-242 requires Connecticut to auction 100% of its RGGI CO2 allowances, and directs the implementing state agencies to allocate the auction proceeds to invest in energy efficiency and renewable energy. Of the RGGI auction proceeds, 75% are to go to the ECMB for energy efficiency and 25% to the Connecticut Clean Energy Fund (CCEF) for renewable energy. Based on an estimated CO2 allowance price of $3-5, the RGGI auction proceeds will result in an additional $22-35 million annually for energy efficiency measures. These funds will not increase electricity rates beyond existing levels. Auctions capture the revenue that would have been directed to generators from their inclusion of a carbon adder in their hourly electricity bids.

The IRP does not mention combined heat and power (CHP), a proven technology that can match demand with load, increase thermal efficiency and reduce the need to operate inefficient and expensive peaking generation. Connecticut's RPS includes class III requirements that at least 4% of the state's electricity demand be satisfied by CHP and energy efficiency by 2010. There are significant opportunities for CHP, as highlighted in a recent report completed by the Institute for Sustainable Energy at Eastern Connecticut State University.[6]

Recommendation 4 of the IRP alludes to Connecticut's reliance on natural gas. The IRP does not provide any assessment of the potential to improve end-use efficiency for this fuel. Connecticut now has a natural gas efficiency program, which is part of the ECMB. One area that could be pursued is to take advantage of opportunities to improve the combustion efficiency of residential and small commercial furnaces. Public Act 07-242 does provide for incentives for furnaces with a thermal efficiency greater than 85%. This level is not very technology forcing. Furnaces with combustion efficiencies greater than 90% are available, and incentives could be directed at these more efficient furnaces to reduce natural gas demand, and help residential consumers to reduce their energy bills.

The IRP did not address improving the efficiency of and reducing dependency on oil use in Connecticut. Public Act 07-242 also provides for the establishment of an oil efficiency program. The IRP should recommend programs that the state could implement to reduce demand for oil, and take advantage of the opportunities created by the legislation to implement DSM programs across all fuels.

Funding Sources to Achieve the Objectives of Section 51

The IRP assumes that the existing ECMB programs will be continued and simply ramped up to increase the amount of energy savings. The IRP does not provide an analysis of existing or potential funding mechanisms that could be used or considered. Appendix D of the IRP references Connecticut's system benefit charge program but does not include discussion on current or potential funding mechanisms that would comply with Section 51c ("all available energy efficiency and demand reduction resources") or with the earlier requirements in sections 51a and 51b.

Connecticut's funding for energy efficiency and renewable energy programs has had a checkered history.[7] The IRP should reflect upon this history, evaluate alternative funding schemes, and the potential for them to complement existing funding to achieve the requirements of section 51. The following principles and issues are important:

- Certainty in funding and amount. Consistency is critical to maintain momentum, build a network of experienced installers and maintenance staff, and for program credibility.
- Program ramp up rates in programs should be based upon reality, capacity of the distribution companies to implement programs and the ancillary service structure needed to maintain installed measures.

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[6] Institute for Sustainable Energy at Eastern Connecticut State University 2004. Distributed Generation Market Potential: 2004 Update/ Connecticut and Southwest Connecticut, available at http://www.easternct.edu/depts/sustainenergy/publication/Press%20Releases/March%2023,%202004%20-%20DG%20Update.htm

[7] $12 million was appropriated for investment in state buildings in 2002. Since 2004, about 1/3 of ECMB funds have been securitized to help balance Connecticut's budget. Another section of Public Act 07-242 directs these funds to be fully restored, but this has yet to occur as of January 2008.

- Auction revenues from the RGGI program are expected to add $22-35 million annually for energy efficiency, and 1/3 that amount for renewable energy investment. These amounts need to be factored into the IRP.
- Connecticut energy efficiency measures are now receiving capacity payments during the transition period for the ISO-NE forward capacity market. The amounts of these capacity payments are known and the full FCM, starting May 2010, will provide additional revenue from energy efficiency resources. The IRP needs to reflect the amounts of the FCM capacity payments into its analysis.
- Auction revenue from "white tags", the MWh associated with energy efficiency programs. This process began in 2007. The auction revenue is known by the electric distribution companies, and should be factored into the IRP.
- Alternative funding mechanisms. Connecticut's energy efficiency program is quite good, but substantial opportunities remain in the low- and fixed-income residential sectors, both for renters and homeowners. Homeowners on fixed-incomes are paying an increased percentage of their incomes for electricity costs and often do not have any discretionary funds to take advantage of energy efficiency programs, much less to pay for even subsidized costs of renewable energy generation. Alternative programs such as PAYS® or equivalent should be evaluated for applicability to these sectors.
- Innovative financing schemes. Alternative means of financing should be considered before any consideration is given to increasing the amount of ratepayer contributions above current levels. While it is clear that DSM remains the most cost-effective resource and that there are significant opportunities to reduce electricity demand substantially, the ratepayer does not have to be the only source from which energy efficiency and renewable energy programs are funded. The IRP should evaluate the ability for private sector investments to complement the existing programs and take advantage of Connecticut's history as "insurance capital" to develop opportunities for new business products. Energy Savings Insurance,[8] using the Connecticut Economic Development Authority's ability to invest in private ventures and potential hedge fund and venture capital, both of which have a strong presence in Connecticut, should be evaluated for their resources, their ability to leverage energy efficiency investments in the ISO FCM and for the creation of new jobs in the insurance sector.

Other points related to achieving all cost-effective energy efficiency

Connecticut has had a good record of adopting building codes and appliance standards. Continuing this progress can help to achieve additional demand reductions, without requiring additional funds from ratepayers or the state. It is equally important to enforce existing building codes and standards, and to assure that local and state building officials receive appropriate training.

Parity in the relationship between ratepayer funding and benefits has been a goal of the ECMB. It is important to continue to strive for parity, especially in the low- and fixed-income

[8] Evan Mills http://eetd.lbl.gov/Emills/PUBS/EnergySavingsInsurance.html

sectors. These households are least able to afford increased energy bills; difficulty in paying bills affects both renters and homeowners. The IRP should evaluate additional programs that could be implemented in these sectors, including innovative financing schemes, as mentioned above.

B. Demand Response and Load Management

The IRP evaluates a "DSM-focus" resource solution in which existing DSM programs are expanded through substantially higher funding levels (page 18). The demand response and load management components of the DSM-focus resource solution consist of a Direct Load Control program offered to residential and small business customers with central air conditioning and a Load Response Program offered to commercial and industrial customers. Those two components are described on pages D-7 and D-11 respectively. The IRP forecasts that the impact of those two programs, combined with the impact of the efficiency components of the DSM-focus resource solution, would result in essentially no increase in net peak demand between 2008 and 2018, as indicated in Figures 2.4 and D.7. The IRP does not provide an analysis of the cost-effectiveness of operating either of these programs at a substantially expanded level. The IRP also notes that "Advances in communication and metering technology may make program offerings possible that could not previously be envisioned. Finally, the new study may assess the likely impact of dynamic pricing programs which are not included in the current plan."

Comments

Section 51 (c) requires, among other items, that the plan specify "….(2) the extent to which demand-side measures, including efficiency, conservation, **demand response and load management can cost-effectively meet these needs"** (emphasis added).

1. The IRP does not provide an analysis of the cost-effectiveness of substantially expanding the operation of either the Direct Load Control program or the Load Response Program.
2. The IRP refers to "…the future deployment of advanced metering infrastructure[9] (AMI) meters and time-of-use rates" on page D-7 and later, on page D-20, to "Advances in communication and metering technology" and to "dynamic pricing programs". However, the IRP does not provide any analysis of the cost-effectiveness of achieving demand response through time differentiated pricing, such as time-of-use rates or dynamic pricing, supported by AMI. The absence of any such analysis is of major concern because there are significant concerns regarding the rate impacts, bill impacts and cost-effectiveness of mandatory time differentiated pricing supported by AMI.

In the past few years utilities in several states have proposed major investments in AMI. Utilities can seldom justify these investments solely upon the projected utility operational savings, which are primarily anticipated reductions in meter reading costs. Instead, utilities

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[9] The Federal Energy Regulatory Commission has defined AMI as a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point.

rely upon the combination of projected operational savings and projected electricity resource cost savings. The projected electricity resource cost savings are primarily anticipated reductions in the costs of incremental generation capacity. Those projected generation capacity savings typically hinge upon demand response achieved by placing residential and small commercial customers on some form of time differentiated pricing,[10] supported by AMI, and relying upon a subset of those customers to voluntarily reduce their load in peak hours in response to the prices in those hours. The anticipated reduction in peak load by that subset of customers is, in turn, expected to defer the need for investment in incremental generation capacity. Since the cost of generation capacity is recovered from all customers, the expected deferral of such costs is considered to be a capacity cost saving to all customers. There are a number of concerns regarding proposals to achieve demand response by mandating time differentiated pricing, supported by AMI, for all residential and small commercial customers.

From an energy and environmental policy perspective the basic concern is that this is not the most cost-effective approach to reducing electricity resource costs, and it does very little to reduce air emissions from electric generation.

- Energy efficiency and direct load control, the other two major approaches to reducing load in peak hours, which do not require AMI, are more cost-effective and could eliminate the need for incremental generation capacity. The IRP is forecasting significant reductions in demand in peak hours from the expansion of existing energy efficiency and direct load control programs, both of which have proven to be cost-effective. In fact, under the DSM-focus strategy it is forecasting no increase in net peak demand between 2008 and 2018. That forecast implies that CT utilities would not need to acquire new generation capacity during that period under that strategy. Thus, it is very difficult to understand how incremental demand response to be achieved through time differentiated pricing supported by AMI could be justified on the basis of avoiding incremental generation capacity.
- Energy efficiency and direct load control have a proven record of sustained performance. In fact, ISO NE now allows program administrators to bid load reductions from these approaches into the Forward Capacity Market, because the program administrators stand behind those commitments and will pay a financial penalty if they fail to perform. In contrast, there are concerns regarding the long-term performance and persistence of load response achieved through time differentiated pricing. Peak load reductions achieved though voluntary responses to time differentiated prices will only produce reductions in incremental generation capacity costs if those reductions are sustained over time. System planners determine the quantity of capacity that is required for reliability based upon long-term forecasts of peak demand. Those long-term forecasts will only be affected by voluntary price response if there are several years of actual results and a confidence that those results will continue at that level. The experience with TOU

[10] Approaches to time differentiated pricing include Time of use rates, Critical Peak Pricing, Critical Peak Rebates, and Dynamic Pricing.

from the 1980's and early 1990's is that participation declined over time.[11] In contrast, the expectations regarding reductions that can be achieved through time differentiated pricing are based upon pilots in California, Illinois and Ontario, none of which have lasted much longer than 2 years

- The focus of most proposals for demand response through time differentiated pricing is on reducing load in a few peak hours, not on reducing energy use throughout the year. Demand response which reduces energy consumption in 50 to 100 hours in a year provides little, if any, environmental benefit in terms of reductions in annual air emissions.

From a ratemaking and individual customer perspective, the basic concern is that all residential and small commercial customers will pay for the investment in AMI but not all customers will have the ability to reduce load in peak hours, and hence many will not realize a net benefit, but instead see rate increases.

- In every utility service territory there is a segment of customers who are unable to reduce or shift usage materially during periods of high price. These include low usage customers who do not have discretionary loads as well as seniors and others who are highly dependent on electricity for health and medical purposes. Many customers in that latter group are unable to reduce or shift usage during periods of high price without significant adverse consequences. The concern is that such customers, and others who are not in a position to reduce their electricity use in peak hours, may simply incur higher bills, i.e. the additional costs they incur under this approach could well exceed the benefits they receive.
- Energy efficiency and direct load control rely upon voluntary customer participation and have a proven record of customer acceptance. In contrast, there are concerns regarding the reaction of the majority of customers to mandatory time differentiated pricing in conjunction with AMI. Under such an approach it is possible that customers who do not reduce their load in peak hours will see an increase in the supply component of their bills in peak months, as a result of time differentiated pricing, as well as an increase in the distribution service component of their bills in every month, as a result of the AMI. There may be ways to minimize the rate and bill impacts on such customers. For example, under the "critical peak rebate" (CPR) approach there would be no change in existing rates. Instead, customers would be notified in advance of impending peak price periods and those who reduced load during those periods would receive the CPR.

3. Power Procurement Structures (IRP recommendation 2)

IRP recommendation 2 is to "Explore other power procurement structures such as longer term power contracts on a cost-of-service basis with merchant and utility owners of existing and new generation." The IRP states that this recommendation is based upon the results

[11] Plexus Research," *Deciding on Smart Meters: the Technology Implications of Section 1252 of the Energy Policy Act of 2005*", Edison Electric Institute, September 2006, page 7.

of its analyses which suggest that "….supply arrangements incorporating cost-of-service principles could help to stabilize customer rates and **potentially, under certain conditions, lower prices** for the customer, " (emphasis added). The IRP states that the Companies could achieve this if they had "…greater flexibility in the structures and duration of their power supply arrangements on behalf of customers. Options may include long-term contracting, procuring energy, capacity and reserve products individually from generators and/or the outright ownership of generating assets…" The IRP also notes that "…strategies such as these should be coupled explicitly with **the assurance of recovery of supply costs associated with approved long term power procurement contracts,"** (emphasis added).

Comments

Section 51 (c) requires, among other items, that the plan specify "….(5) the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources."

1. IRP recommendation 2, while reasonable, recommends an analysis that the Companies should have provided in their IRP in order to comply with Section 51 (c) (5). The IRP should have identified and evaluated alternative approaches to acquiring supply for standard offer service (SOS). Those alternative approaches would be different portfolios of short-term contracts, long-term contracts, contracts for energy, capacity and reserve products from specific generators and/or outright ownership of generating assets. The IRP should have provided an evaluation of the expected price and price stability of each alternative approach and recommended a specific approach, one that offered the best combination of expected price and price stability over time. A recent example of an evaluation of alternative portfolios in a state with retail competition is presented in the Additional Reply Testimony of Jonathan Wallach filed December 21, 2007 in Maryland Case No. 9117.[12] An example of an evaluation of alternative portfolios in a state without retail competition is presented in Northwestern Energy, Inc.'s Electric Supply Resource Procurement Plan (2005)[13].
2. The IRP indicates that the Companies will want "…the assurance of recovery of supply costs"[14] in order to move to new strategies that include long term power procurement contracts and/or ownership of generating assets. This request represents a key issue that the Connecticut Department of Public Utility Control and other stakeholders will have to address if and when the Companies propose a specific plan for procurement of supply resources that include some portion of long-term contracts and/or ownership and hence long-term cost commitments. The issue is whether it is appropriate to provide any form of cost recovery assurance in advance. A second, related issue is the determination of the benchmark, standard or test that should be applied in order to determine

[12] http://webapp.psc.state.md.us/Intranet/CaseNum

[13] http://www.montanaenergyforum.com/plan.html

[14] IRP, ES-5.

the prudence of such an approach, either in advance of its implementation or after actual costs have been incurred. Both issues must be addressed in order to determine whether the costs that are expected to result from a specific proposed approach, or actually do result from that approach, will be or are "just and reasonable" and hence eligible for recovery in rates.

Under the current approach to acquiring supply for standard offer service, i.e., a portfolio of three-year full requirements contracts, the supply prices that result from the acquisition process are apparently been considered just and reasonable based upon comparisons to a generally accepted public benchmark, i.e., futures prices for the particular contract period, and based upon the fact that customers have the option of "voting with their feet" by migrating from SOS to a competitive retail marketer. In contrast, there is no generally accepted public benchmark against which to compare the costs of supply beyond approximately three years, because futures prices beyond that point are not considered to be accurate. Therefore, determination of the prudence of a procurement approach involving cost commitments beyond 3 years will require a transparent evaluation of the performance of alternative portfolios under a range of possible future resource costs, and a decision as to the portfolio with the best combination of expected cost and cost stability. This will also be particularly important to avoid potential exposure to stranded costs in the event that customers migrate from SOS. (Note that this can largely be avoided through a portfolio with sufficient short-, medium-, and long-term contracts so that modest changes in the customer load due to migration to alternative suppliers can be managed with changes in the portfolio.)

4. Renewable Portfolio Standards (IRP recommendation 3)

IRP recommendation 3 is to "Evaluate the structure and costs of Connecticut's renewable portfolio standard (RPS) in the context of a regional re-examination of the goals and costs of similar policies in New England." The IRP indicates that this recommendation is based upon a concern that Connecticut's renewable portfolio standard as currently structured "…may impose additional costs on Connecticut customers without necessarily promoting new renewable generation to displace conventional generation." It suggests, on page ES-6, that "…the criteria for disbursing funds derived from alternative compliance payments might be re-examined". Later, on pages E-5 and E-6, it notes that the alternative compliance payment (ACP) in CT is not adjusted for inflation, unlike other New England states, and that "…the most important aspect of the Connecticut RPS is the constant ACP price that is not adjusted for inflation over time."

Comments

Section 51 (d) requires, among other items, that the plan consider "….(2) the extent to which generation needs can be met by **renewable** and combined heat and power facilities" while Section 51 (c) requires, among other items, that the plan specify "….(5) the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources."

1. The IRP does not evaluate the extent to which generation needs can be met by **renewable** facilities, and therefore fails to comply with Section 51 (d). For example, the IRP states on page ES-6 that" Although not assessed in this report significant renewable generation could also mitigate gas dependence."
2. The IRP states that none of projects approved under Round 2 of Project 100 "…are **currently competitive** even with REC prices at $25/MWh" (emphasis added). This is the wrong reference point or benchmark. Instead, the IRP should compare the estimated levelized cost of the electricity from these resources over time to the estimated levelized cost of electricity from natural gas, coal and nuclear resources over time, including the cost of compliance with anticipated CO_2 regulation. The same comment applies to the estimates of levelized costs presented on page E-13.
3. The IRP fails to state that the Round 2 request for proposals (RFP) under Project 100 was limited to facilities located in Connecticut. There is evidence that a future RFP without such a constraint would attract may more proposals. For example, the IRP notes on page E-5 that the renewable projects in the ISO NE Interconnection Queue (8,866 GWh) exceed the incremental requirements for RPS in New England between 2006 and 2012 (5,881 GWh). The IRP then expresses some doubt as to whether all of these projects will come into service. However, that opinion is not supported by a detailed study as the IRP explicitly states that it did not analyze the future renewable energy development in New England.
4. IRP recommendation 3 is a reasonable suggestion, particularly with respect to opening RPS solicitations to facilities located outside of Connecticut and to considering making the state's ACP consistent with the ACP in other New England states.

5. Mitigating Exposure to Price and Availability of Natural Gas (IRP recommendation 4)

IRP recommendation 4 is to "Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas."

Comments

The exposure of Connecticut consumers to the price and availability of natural gas under a continuation of current policies has serious implications for the reliability and price of their electricity supply. However, that exposure does not warrant a separate study or recommendation. Instead, the IRP should have addressed that cost and risk exposure in the development of a specific plan to comply with Section 51 (d), i.e. one that considers:

1. Approaches to maximizing the impact of demand-side measures
2. the extent to which generation needs can be met by renewable and combined heat and power facilities

3. the optimization of the use of generation sites and generation portfolio existing within the state
4. fuel types, diversity, availability, firmness of supply and security and environmental impacts thereof, including impacts on meeting the state's greenhouse gas emission goals;
5. reliability, peak load and energy forecasts, system contingencies and existing resource availabilities;
6. import limitations and the appropriate reliance on such imports; and
7. the impact of the procurement plan on the costs of electric customers.

A specific plan that complied with those requirements would mitigate the exposure of Connecticut consumers to the price and availability of natural gas.