2008 Comprehensive Plan for the Procurement of Energy Resources

Prepared by:

The Connecticut Energy Advisory Board

Approved August 1, 2008

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EXECUTIVE SUMMARY

To comply with Section 51 of Public Act 07-242, the Connecticut Energy Advisory Board (CEAB) submits this *2008 Comprehensive Plan for the Procurement of Energy Resources* to the Department of Public Utility Control (DPUC) for its review, modification as appropriate, and final approval. In general, Section 51 provides that there shall be an annual review of the state's energy and capacity resources and a corresponding comprehensive plan for the procurement of energy resources to meet the projected requirements of Connecticut customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.

General Recommendations. The Procurement Plan sets forth a series of recommendations in Section 1. In broad terms, these recommendations are to:

- Implement the more aggressive demand-side management objectives in a way that remains sensitive to the near term ratepayer cost impacts, and minimizes costly investments in new generation and transmission.
- Increase the development and lower the costs to Connecticut consumers of renewable energy through long-term contracts.
- Use bilateral and long-term generation contracts within wholesale markets that provide price stability or price reductions to mitigate the extent to which Connecticut's electric costs are tied to natural gas prices.
- Ensure that all procurement and investment decisions consider that a meaningful amount of current Connecticut generation could retire over the next ten years.

The specific recommendations concerning procurement, demand-side management, renewable energy generation, conventional generation, and emissions management are listed for convenience in Section 3 of the Plan. Also, in Sections 3 and 4, the CEAB sets forth recommendations to guide analysis in future planning cycles, which includes identification of unresolved issues.

Background. Section 51 directed the CEAB to review, modify as appropriate and approve a resource plan submitted by Connecticut's electric distribution companies. The CEAB is to submit the Plan to the DPUC for its consideration.

On January 1, 2008, Connecticut's electric distribution companies — Connecticut Light & Power (CL&P) and United Illuminating (UI) — submitted their 2008 Integrated Resource Plan (IRP) to the CEAB.

Since that time, the CEAB assessed the IRP and undertook a series of activities to move the Plan forward in several areas. At the outset, the CEAB:

- Performed a Preliminary Assessment of the IRP to measure its conformance to the statutory criteria set forth in Section 51.
- Reviewed the IRP's technical details through discussions with CL&P and UI.
- Sought and received Written Comments on the IRP.
- Held a public hearing.

As a result, the CEAB determined that the first iteration of the IRP did not adequately conform to Section 51 requirements and that several key areas warranted further analysis. The timeframes allotted to the electric distribution companies and the CEAB to prepare the first iteration of what will be an annual plan limited the ability to develop a plan that conforms squarely to that contemplated by Section 51. The CEAB is confident that additional planning cycles, further analysis and continued collaboration among all participants will result in a comprehensive and valuable planning tool.

Thereafter, the CEAB conducted a collaborative, four-month effort to address six key areas. They include: 1) procuring energy resources; 2) managing energy demand or demand-side management (DSM); 3) developing renewable energy; 4) generating sufficient electricity; 5) reliably transmitting electricity; and, 6) managing emissions to comply with Connecticut's environmental standards.

Toward this end, the CEAB met with CL&P and UI; consulted with the ISO New England; engaged in numerous conversations with interested parties; and, conducted a dozen stakeholder workshops. The CEAB gained valuable information to advance the Plan within the confines of this first planning cycle through these processes and appreciates participants' time and input.

The resulting Procurement Plan includes the CEAB's recommendations to inform Connecticut's resource investment decisions and to plan for procuring the necessary resources; and to plan for future needs. Importantly, to the extent feasible in this initial planning cycle, the CEAB endeavored to identify a viable action item for implementing the recommendations. Finally, the CEAB recommends near term action items for CL&P and UI, the DPUC, the CEAB, and other entities to continue to move the Procurement Plan toward the mature and comprehensive resource planning contemplated by Section 51.

1. ACTION PLAN

1.1. Introduction

1.1.1. Background

Section 51 of Public Act 07-242, *An Act Concerning Electricity and Energy Efficiency*[1] calls for the CEAB to annually review, assess, and approve a comprehensive plan for the procurement of energy resources, along with a statement of any unresolved issues, and submit the plan to the Department of Public Utility Control (DPUC) for its consideration.

As set forth in Section 51, the CEAB has reviewed the January 1, 2008 resource planning assessment and procurement plan recommendations submitted to the CEAB by Connecticut Light & Power (CL&P) and United Illuminating Company (UI) (together "the Distribution Utilities").

This *2008 Comprehensive Plan for the Procurement of Energy Resources* (Procurement Plan) is the first such plan to be prepared under Section 51.

1.1.2. The Procurement Plan's Purpose

The key component of the Procurement Plan is Section 1, the Action Plan.

In this Procurement Plan, the CEAB's recommends actions for the DPUC to consider and calls for further planning activities by the Distribution Utilities, the CEAB, and others to be included in future, annual Procurement Plans. In formulating its recommendations, the CEAB integrated, to the extent possible, DPUC Decisions and ISO New England requirements. While the 2008 Procurement Plan was developed, the DPUC issued several related Decisions

[1] See Appendix A for the complete text of the Section 51 statute.

(such as reviewing Connecticut Energy Efficiency Fund incentives) that are generally consistent with the CEAB's recommendations.[2]

The CEAB hopes this Procurement Plan helps all entities involved in Connecticut's electric energy system better understand how their individual planning and resource procurement decisions impact these same decisions by other entities.

In recent years, procurement-related decisions have focused on expanding peaking capacity and reducing peak demand to address the critical reliability needs in the state and address the associated federally mandated congestion costs.[3] The remaining local capacity requirements have been substantially addressed by DPUC's Final Decision in Docket No. 08-01-01, *DPUC Review of Peaking Generation Projects* (dated June 25, 2008), in which it selected three peaking generation projects totaling almost 700 megawatts.

In this Action Plan, the CEAB recommends shifting the focus from reliability-based issues to the next critical areas: maximizing demand-side management (DSM) options and securing renewable resources. While DSM and renewables require the most immediate action, focus cannot be lost on the other key areas: generating sufficient electricity; reliably transmitting electricity; and, managing emissions to comply with Connecticut's environmental standards. The state must be aware of how these key areas interact and anticipate how a decision in one area affects another area for Connecticut and the region. As such, the Action Plan addresses planning activities to deal with these interactions.

1.1.3. The Distribution Utilities' Integrated Resource Plan

On January 1, 2008, the Distribution Utilities responded to Section 51 for a resource plan by jointly filing an Integrated Resource Plan (IRP) for Connecticut. This plan was prepared by The Brattle Group under the direction of and on behalf of the Distribution Utilities. The IRP analysis modeled four resource solutions to evaluate their effect on cost and other metrics (such as the environment). The resource solutions were conventional gas, DSM, nuclear, and coal.[4] The Distribution Utilities developed various metrics to show costs to consumers and the total going-forward cost differences among potential resource plans. The

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2 For details, see DPUC's Final Decision in Docket No. 07-10-03, *DPUC Review of The Connecticut Light & Power Company's and The United Illuminating Company's Conservation and Load Management Plan for the Year 2008* (dated June 19, 2008) and DPUC's Draft Decision in Docket No. 07-06-61, *DPUC Examination of Electric Distribution Company Contracts For Renewable Energy Certificates*.

3 See, for example, DPUC Final Decision Docket No. 07-06-59, *DPUC Review of Connecticut Electric Efficiency Partners Program*, dated June 4, 2008.

4 See IRP, Section IID, beginning on page 15.

Distribution Utilities highlighted ten key findings from analysis of the metrics[5] and made four recommendations.[6] They are as follows:

1. Maximize the use of demand-side management within practical, operational, and economic limits, to reduce peak load and energy consumption.
2. 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.
3. Evaluate the structure and cost of Connecticut's renewable portfolio standard by re-examining of the goals and costs of similar policies in New England.
4. Consider potential ways to mitigate exposure of Connecticut consumers to the price and availability of natural gas.

1.1.4. CEAB Review Of The Distribution Utilities' Integrated Resource Plan

The CEAB conducted an extensive review of that IRP, including:

1. Assessing if the IRP complied with the statutory criteria.
2. Soliciting public comment on the IRP from numerous organizations and individuals.
3. Conducting a public hearing on the IRP.
4. Conducting technical review of the IRP through technical workshops with the Distribution Utilities.

Based on that review process, the CEAB determined that the IRP, while laying important groundwork, did not sufficiently comply with the Section 51 requirements. The CEAB appreciates that the time the Distribution Utilities had was short and that a fully developed IRP as contemplated by the statute may require several planning cycles.

As a consequence, the CEAB determined that more analysis was needed for several key areas: demand-side management, renewable energy, existing Connecticut generation, transmission, and managing emissions to comply with environmental standards.[7] This Procurement Plan addresses each of these key areas.

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[5] These findings are provided in Appendix B of this report and in much detail within the IRP, Section IIB beginning on page 39.

[6] These recommendations are also provided in Appendix B of this report and discussed more fully in the IRP, Section IV beginning on page 45.

[7] See the "Public Comment Summary" section in Appendix D: CEAB March Letter to Energy and Technology.

The CEAB adopted a four month work plan with the Distribution Utilities and key stakeholders to further analyze each of these key areas. At that time, the CEAB informed the Energy & Technology Committee that the Procurement report would be filed on August 1, 2008. The DPUC would then begin their 120-day review.

1.1.5. The Collaborative Process

The CEAB collaborated extensively with the Distribution Utilities and many others to meet the statutory requirements of the Procurement Plan. The CEAB held meetings with the Distribution Utilities, ISO New England, and other key stakeholders to research and gather the information needed to perform the additional analysis.[8] During this process, the CEAB focused on structuring its recommendations to move the overall planning process forward and create an actionable plan for the DPUC's consideration.

The Distribution Utilities actively participated in this process, supported the CEAB's review of the IRP, provided additional analysis, and helped facilitate stakeholder workshops. Many stakeholders participated in 12 workshops and engaged in many conversations with the CEAB that led to much valuable information.[9]

The CEAB is grateful for these many contributions. They helped make meaningful progress on the key areas, and enabled the CEAB to develop this Action Plan and its requisite recommendations.

1.1.6. Scope of the Procurement Plan

The CEAB recognizes that energy markets are in constant flux and understands how this affects policy implementation. Over the last year while the IRP and Procurement Plan were being created, many significant changes have occurred (such as, for example, the dramatic increase in oil prices and DPUC Decision Docket No. 08-01-01 on June 25, 2008 which procured peaking resources). The effects of these market changes could not be fully taken into account. The CEAB will carefully consider these and other ongoing changed in subsequent planning.

The procurement planning requirements became effective on July 1, 2007, compressing the time available during this first annual planning cycle[10] and thus limiting what could be accomplished. The Distribution Utilities and the CEAB

8 A detailed account of the consultations, public input, and analyses conducted by the CEAB, in collaboration with the Distribution Utilities, is found in Appendix E: Status Report: Conclusion of Stakeholder Input Process.

9 See Section 2.3: Utilities and CEAB Collaborative Efforts" for details about the public hearing and stakeholder input processes.

10 [Insert an explanation of the schedule change.]

have made every effort to move the Plan toward the type of comprehensive plan contemplated by Section 51. The CEAB, however, acknowledges that while this first report does not in its view, fully conform to Section requirements, subsequent plans will assuming continued analysis and collaboration.

To facilitate the DPUC's review, the CEAB has tried to make clear which requirements have and have yet to be met, and to describe how these shortcomings will be addressed in future planning cycles.[11] In addition, this year's tight schedule did not allow for a formal comment period. Therefore, the recommendations in this Procurement Plan are those of the CEAB and do not necessarily reflect those of the Distribution Utilities or any other stakeholder that participated in our workshops and meetings.

1.1.7. Structure of the Action Plan

The Action Plan makes a number of recommendations in six key areas. The Action Plan also specifies the action items needed to implement these recommendations, understanding that actions might change due to changing circumstances and new information. The six areas (and their related sections) are:

- Section 1.2: Overall procurement direction (page 10).
- Section 1.3: Demand-side management (page 16.)
- Section 1.4: Renewable energy (page 22).
- Section 1.5: Connecticut generation (page 29).
- Section 1.6: Transmission-related issues (page 36).
- Section 1.7: Emissions management (page 40).

For each recommendation, the CEAB delineates these topics:

- Procurement Plan Statutory Obligations
- Current Connecticut Programs and Policies
- Summary of the Distribution Utilities' IRP Findings
- CEAB Analysis and Observations
- Procurement Actions
- Future Resource Planning Actions

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11 In its preliminary review of the Distribution Utilities' Procurement Report, the CEAB provided an assessment of the IRP relative to the enabling legislation. This assessment, detailed in Appendix C: CEAB Preliminary Assessment of the Integrated Resource Plan, also offers a scorecard that indicates the progress made since the Distribution Utilities issued their report.

By organizing the Procurement Plan this way, the CEAB identifies the longer term direction established from the planning process and identifies the near-term actions needed to execute the recommendations.

Following the Action Plan are four additional sections:

Section 2: CEAB Action Plan Development and Public Process contains an overview of the process the CEAB used to reach its conclusions including a description of the public and stakeholder input process.

Section 3: Compilation of Recommendations assembles all of the recommendations organized under procurement actions and future resource planning actions. This section reflects the substantive recommendations in Section 1: Action Plan, compiled for the convenience of the reader.

Section 4: Guidelines for 2009 Plan and Future Procurement Plans describes the recommended steps the Distribution Utilities take developing the 2009 Procurement Plan.

In Section 5: Action Items, the CEAB outlines action items each responsible entity could take to implement the recommendations presented in Section 1. This section does not contain new or additional information but rather presents recommendations previously discussed for the convenience of the reader.

Finally, the Appendices provide the documentation, resources, and analyses used to create the IRP and on which the recommendations for action are based.

1.1.8. Future Planning Process

In the CEAB's view, any planning process must be a continued effort toward procedural and substantive improvement. The CEAB intends to revise and improve the planning process annually. This first planning cycle addressed several key issues, however more work lies ahead. The CEAB is committed to collaborating with the Distribution Utilities and seeking input from other stakeholders to fulfill obligations in the procurement planning process. In the CEAB's view, collaboration enables good planning, considers the latest information, factors in anticipated regulations and market changes, analyzes and tests for contingencies, and remains the most efficient way of serving Connecticut's ratepayers.

The CEAB will make continued collaboration and involvement from all stakeholders an integral part of future planning.

1.1.9. Next Steps

Section 52 of Public Act 07-242 places implementing the Procurement Plan under the DPUC's authority.

The CEAB, the Department of Environmental Protection (DEP), and the Distribution Utilities must also act on some of the non-procurement related recommendations.

The CEAB hopes the Action Plan and the attending documents to provide insight and guidance to other Connecticut and region area entities as they make plans and decisions for their own actions related to Connecticut's energy requirements.

The CEAB is convinced that last year's procurement planning process, while imperfect, has been valuable. The CEAB intends to review its own processes and identify ways to maximize efficiency and best meet the legislative intent associated with integrated planning. In that process, the CEAB intends to communicate with the Distribution Utilities, other stakeholders, and the DPUC as appropriate to determine whether any statutory modifications may be advisable to achieve the most productive, efficient, and responsive planning process possible.

1.2. Procurement Recommendations

1.2.1. Procurement Plan Statutory Perspective

The core of this planning process is recommendations for actions to obtain needed energy resources for Connecticut's electric customers.

Section 51 calls for the electric distribution companies, in consultation with the CEAB, to "develop a comprehensive plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements for their customers."[12] In addition, Section 51 sets forth a number of priorities and considerations for the development of this plan (see "Section 51 Requirements" below), including requiring plan to specify how each of the proposed resources should be procured, including the optimal contract periods for various resources.[13]

Section 51 Requirements

(b) On or before January 1, 2008, and annually thereafter, the Distribution Utilities shall 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.

(c) 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 CEAB understands the "comprehensive plan for the procurement of energy resources" (this Procurement Plan) requirement to be a call for actionable recommendations for procuring needed resources based on and supported by the assessments of resource needs and alternatives. Thus, this "Procurement Recommendations" section contains the CEAB's recommendations on actions that should be considered by the DPUC and the Distribution Utilities, including recommendations for further planning or assessments needed for future procurement actions.

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12 See Connecticut General Statute Section 16a-3a(a).

13 See Connecticut General Statute Section 16a-3a (b) and (c).

1.2.2. Current Connecticut Programs and Policies

The CEAB focused its recommendations on procurement activities specifically described in Section 51.

Connecticut currently has mechanisms and processes for procuring a range of resources. Connecticut procures energy efficiency and renewable resources through various methods such as the Connecticut Energy Efficiency Fund (see page 16), the Electric Efficiency Partners Program (see page 17), the Connecticut Clean Energy Fund (see page 22), and other programs. By statute, Connecticut procures generation service from a competitive electric supplier for customers who need it (referred to as Standard Service[14]).

The DPUC, benefiting from of substantial input from the electric distribution companies, competitive suppliers, consumer representatives, and other interests, has considerable experience and perspective on matters related to procuring generation. Two examples illustrate this point. The DPUC issued a Draft Decision supporting the use of long-term Renewable Energy Certificates (REC) Contracts and in another case, issued a Final Decision concluding that long-term bilateral contracts may be used for standard service and that shorter term hedging under the current system does not pose risks to competition or stranded costs, and could be used if potential benefits exist.[15]

1.2.3. Summary of the Distribution Utilities' IRP Findings

In its IRP, the Distribution Utilities recommended considering additional DSM and potentially using long term cost of service contracts. The IRP contained no specific procurement plan recommendations.

While reviewing the IRP, the CEAB considered these issues and addressed them in its recommendations.

1.2.4. CEAB Analysis and Observations

The CEAB and the Distribution Utilities conducted a workshop (via conference call) to give stakeholders an opportunity to comment about how resources might be procured as a result of the Procurement Plan. The Retail Energy Suppliers Association was particularly active in this dialogue. The following are highlights of that stakeholder dialogue:

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14 See Connecticut General Statute Section 16-244c.

15 See DPUC Final Decision Docket No. 06-01-08RE01, *DPUC Development and Review of Standard Service and Supplier of Last Resort Service: Plan Approval—Bilateral Contracts Outside of Auction*, dated April 2, 2008 and DPUC Final Decision Docket No. 07-06-58, *DPUC Report to Connecticut General Assembly on Standard Service Procurement*, dated April 2, 2008.

- Energy Conservation Management Board (ECMB) representatives expressed concern that the “procurement plan is capacity focused,” even though Section 51 speaks to “energy requirement.” The ECMB advised the procurement plan be based on meeting energy needs.
- In general, participants said Section 51 recommendations have to work in concert with Section 52, the implementation provision.
- Considerable discussion ensued on harmonizing recommendations with the DPUC Final Decision on procurement related matters, a decision that benefited from substantial input and process. Participants questioned whether recommendations will re-examine issues previously settled by the DPUC.
- Ambiguity arose about the current limitation on long-term contracting to 20% of standard service load. The Decision did not establish the basis that should be used to determine estimates of long-term standard service load.
- Participants questioned whether the Procurement Plan is limited to:
    - Assets: contracting with existing or new assets for their output; building new generation facilities; or creating incentives for constructing particular types, amounts, or locations for capacity.
    - Wholesale level: bilateral contracting for energy for providing hedges to manage price risks for procuring standard service, which could include other transactions that are not specific unit contracts nor are they full requirements service contracts.
    - Retail level: recommendations and activities directly affecting the standard service pricing, which would impact more than reliability and risk management.
- Participants suggested the state and/or its utilities become more active in procurement activities needs to balance the merchant process to the contract process (or build).
- Participants suggested that future IRP analyses should address natural gas infrastructure investments to reduce volatility of the electric energy markets.

For a comprehensive discussion of this analysis, see Appendix F: Connecticut Procurement Activities and Regulations.

1.2.5. Procurement Actions

RECOMMENDATIONS	
1.	The immediate focus of resource acquisition procurement actions should be demand-side management and renewable energy credits.
2.	The IRP supports the potential benefits of bilateral contracting as a means to stabilize and/or reduce standard service rates. Consider combining bilateral and REC contracting.
3.	No other resource acquisition procurement activities are recommended in this 2008 Procurement Plan.

Recommendation 1

The IRP analysis and the supplemental CEAB review produced objectives in the areas of additional DSM, and regional renewable energy project development to meet Renewable Portfolio Standard (RPS) requirements. The CEAB recommends that DSM and renewable energy are the focus of the DPUC's Procurement Plan implementation proceeding and the DPUC and Distribution Utilities near term procurement efforts.

Increases in energy efficiency can be implemented through ratepayer funded programs or through changes to appliance efficiency standards, building code changes or other means. Section 1.3 addresses the dual objectives of a long term target of increased DSM focus and the near-term objective of being highly sensitive to the economic distress that ratepayers are experiencing this year.

The Distribution Utilities' IRP raised concerns about the likelihood of the renewable energy development market meeting the regional New England RPS requirements. The likelihood that the Connecticut RPS requirements can be met is greatly enhanced through long-term REC contracts with the renewable energy generation facilities. Section 1.4 addresses the renewable energy recommendations resulting from the stakeholder collaboration process.

Recommendation 2

The Distribution Utilities' IRP results demonstrated that Connecticut electric costs are highly related to natural gas pricing and, as a result, are exposed to the price level and price volatility of natural gas. The analysis also shows that ISO New England prices are likely to be highly correlated to natural gas prices for some time. The use of bilateral contracts allow for alternative pricing arrangements that may provide some price stability and/or price reductions relative to the gas-related wholesale spot market. For this reason, the CEAB recommends that the DPUC and the Distribution Utilities consider testing the market for combined bilateral contracting of power with the REC contracting to determine if renewable energy, price stability, and cost reduction objectives can be met with this approach. Section 1.4 contains additional discussion of renewable energy contracting recommendations.

Recommendation 3

There is no immediate need for further capacity procurement activity by the DPUC or the Distribution Utilities. This conclusion is based on the assessment of capacity needs conducted in the Distribution Utilities' IRP, coupled with the more recent selection of 700 megawatts of peaking generation in the Cost of Service generation process. The CEAB recognizes further assessment of the retirement risks associated with the existing fossil-fired steam units in Connecticut, which may lead to revisiting the need for capacity procurement in the next planning cycle.

1.2.6. Future Resource Planning Actions

RECOMMENDATION	
4.	The DPUC should consider establishing the generation procurement framework under Section 52 in advance of future plans that may counsel construction of new generation.

Recommendation 4

This 2008 Procurement Plan does not recommend the construction of any generation facility. However, as noted in Recommendation 3 and discussed further in Section 1.5, the risk of retirements may lead to the identification of need for new or repowered generation facilities in subsequent planning cycles. The CEAB recommends that the DPUC consider establishing the generation procurement framework under Section 52 in advance of future plans that may counsel construction of new generation.

Section 52(b) sets forth requirements for a DPUC request for proposals process in the event that the Procurement Plan specifies the construction of a generation facility.[16] Historically, the DPUC has established the framework of solicitations for new generation sources in advance of issuing an RFP for specific resources. The CEAB believes that establishing the process through which the DPUC would execute generation procurement pursuant to Section 52 would make sense to provide the market clarity on implementation issues. This process should include mechanisms for life extension and repowering options, consistent with the

[16] See Connecticut General Statute Section 16a-3b(b).

requirement in Section 51 to consider the optimization of the use of generation sites and the generation portfolio existing within the state.[17]

[17] See Connecticut General Statute Section 16a-3a(d)(3).

1.3. Demand-Side Management Recommendations

1.3.1. Procurement Plan Statutory Perspective

The Procurement Plan must demonstrate a preference for meeting resource needs through energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible.[18] The Procurement Plan must specify, among other items, the total amount of energy and capacity resources needed to meet the requirements of all customers and the extent that demand-side measures — efficiency, conservation, demand response, and load management — can be maximized and cost-effectively meet these needs.[19] This requirement to meet needs through energy efficiency and demand reduction resources continues Connecticut's current policy preference for energy efficiency and DSM.[20]

1.3.2. Current Connecticut Programs and Policies

The primary DSM funding source is the Conservation and Load Management Fund, commonly referred to as the Connecticut Energy Efficiency Fund (CEEF). Electricity customers fund the CEEF on a cents per kilowatt hour basis, an amount set by statute.[21] The Distribution Utilities administer these programs with advice and assistance from the Energy Conservation Management Board (ECMB). The DPUC oversees all aspects of the CEEF, including incentive levels, program cost-effectiveness, fund management, and other changeable emphasis (such as the prior focus on southwestern Connecticut during the period of system constraint).[22]

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18 See Connecticut General Statute Section 16a-3a(c).

19 See Connecticut General Statute Section 16a-3a(d).

20 See Connecticut General Statute Section 22a-200c(d) which directs that any value allocated to the energy conservation and load management program on behalf of electric ratepayers from the Regional Greenhouse Gas Program shall be incorporated into the planning and procurement process under Connecticut General Statute Section 16a-3a and 16a-3b.

21 See Connecticut General Statute Section 16-245m.

22 See DPUC Final Decision Docket No. 07-10-03, *DPUC Review of The Connecticut Light & Power Company's and The United Illuminating Company's Conservation and Load Management Plan for the Year 2008*, dated June 19, 2008.

In recent years, Connecticut has further encouraged energy efficiency by establishing other programs and funding sources. Most of the programs' funding amounts and focus areas[23] are set by statute and include:

- Energy Independence Act Near-Term Federally Mandated Congestion Charges (FMCC) Reduction Measures which focused on measures that could be implemented by January 2006.
- The Electric Efficiency Partnership Program (EEPP) to fund energy efficiency measures that reduce peak demand.
- Class III RPS for electric savings created at commercial and industrial facilities.

Potential sources of funding include:

- Connecticut's Regional Greenhouse Gas Initiative (RGGI)
- Non-ratepayer supported mechanisms (such as private institutional loans for energy efficiency)
- ISO New England's Forward Capacity Market (FCM)

1.3.3. Summary of the Distribution Utilities' IRP Findings

In their IRP, the Distribution Utilities recommended aggressively expanding demand-side management (DSM) to the maximum extent possible. Their detailed proposal for programs and funding is called the DSM Focus case. The level of energy efficiency and demand response included within the DSM Focus case, in effect, eliminates demand and energy growth over the next ten years.

The reference level of DSM program growth described in the IRP will require a combined funding total of $134 million in 2012 for UI and CL&P.[24] That level of program growth would bring annual DSM benefits from all historical and new expenditures to 762 megawatts and 1,466 gigawatt hours by 2012.[25] To achieve the expanded levels of DSM described in the IRP's DSM Focus case would require significant increases in program funding above the reference DSM funding. This expanded DSM program would require $296 million of funding in 2012 and peaks at a funding level of $352 million in 2014, over $200 million more than the reference plans.[26] These programs could then reach savings of over 1,630 megawatts (25% of 2007 peak demand) and nearly 5,400 gigawatt hours (17% of 2007 energy needs).

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[23] More details on funding resources are available in Appendix G: CEAB Review of Demand-Side Management Opportunities.

[24] See IRP, Appendix D, Table D.8.

[25] See IRP, Appendix D, Tables D.4 and D.6.

[26] See IRP, Appendix D, Tables D.8 and D.9.

1.3.4. CEAB Analysis and Observations

The Distribution Utilities derived the DSM Focus case costs and impacts on peak demand and energy consumption largely from the potential for energy efficiency identified in a 2004 study. These costs were then adjusted for known changes that occurred since that study was conducted (such as technology, building stock, and avoided costs). Based on this, the programs included in DSM Focus case were estimated to be cost-effective. The Distribution Utilities included a timetable for ramping up the funding of the programs to establish that the IRP is practical.

The IRP analysis is based on the most recent, yet dated, economic potential study. The ECMB has commissioned a comprehensive updated economic potential study with results expected in the fall of 2008. Lacking an up-to-date assessment of DSM potential, the Distribution Utilities' plan does a credible job taking into consideration known and expected changes (such as new appliance efficiency) in adapting the 2004 economic potential study in its IRP.

To further study the DSM potential, the CEAB conducted a DSM Stakeholder Workshop with interested parties. Highlights are as follows:

- Public comments overwhelmingly favor expanding DSM programs.
- ECMB representatives emphasized the cost effectiveness and the high level of customer demand for program services. They attributed this demand to the sharp increases in consumer energy costs and the basic program designs that provide incentives close or equal to the full incremental cost of energy efficiency measures.
- ECMB has mobilized its budget request to the DPUC to establish a level that would begin the ramp up to the DSM Focus level of programs.
- Other than ratepayer funding, no specific mechanisms for funding the DSM Focus programs have been developed.
- Potential alternative funding mechanism mentioned for the DSM programs included loans, reduced incentives, program design changes to minimize administrative and delivery costs, and some non-program options (such as increasing efficiency standards of electrical equipment and building code requirements for efficient equipment).

The CEAB agrees with the observation that efforts to increase end-use efficiency and lower peak demand more aggressively will yield important long-term cost reductions to Connecticut consumers. The Distribution Utilities' IRP DSM analysis demonstrated, however, that rates could rise in the near term.[27] The

[27] In the DSM Focus Resource Case, an examination of IRP Figures 3.2 through 3.9 shows that while total annualized long-term costs to consumers are lower, short-term Average Unit Costs and Total Customer Costs are higher.

CEAB notes that the IRP did not evaluate alternatives to direct ratepayer-subsidized programs to help minimize these near term rate increases required by the increased cost of the DSM Focus programs. As noted earlier, the Distribution Utilities primarily derived the DSM programs (and their costs and impacts) from the 2004 economic potential study, adjusted for updating "underlying costs and savings" making it "the most current estimate of potential in Connecticut."[28] The IRP had not been able to extensively review and evaluate new program incentive levels and designs.

Read Appendix G: CEAB Review of Demand-Side Management Opportunities for a summary of this analysis.

1.3.5. Procurement Actions

RECOMMENDATIONS	
1.	The IRP supports adopting demand response (DR) and energy efficiency (EE) program levels as defined in the DSM focus case as the 3–5 year objective.
2.	The DPUC should investigate whether DSM Focus case objectives can be reasonably met in a cost-effective manner compared to generation and transmission while minimizing ratepayer and CEEF funding.
3.	The DPUC should determine the appropriate ramping up for DSM Focus, balancing the results of the Utility Cost Test and Total Resource Cost Test for cost-effectiveness with near term rate impacts.

The CEAB offers three DSM recommendations. In the CEAB's view, the first could be implemented by the DPUC in the context of approving a Procurement Plan. The other two could be implemented by the DPUC in other proceedings, such as the annual docket in which the CEEF budget and programs are approved.

Recommendation 1

The CEAB recommends the DPUC adopt the levels of energy efficiency and demand reductions through demand response programs specified in the DSM Focus case as objectives for the ECMB and the Distribution Utilities. Reductions in peak demand can also help offset the need for potentially more costly investments in new generation and transmission and further Connecticut's air quality goals.

This translates to an approximate savings of 1,466 megawatts of peak demand. The ECMB and the Distribution Utilities would be required to develop plans that

[28] See IRP, page D-2, paragraph 2.

achieve the DSM focus case objectives or show why the levels are no longer considered either viable or economically beneficial. In adopting the DSM focus case objectives, the DPUC would review all program budget levels and rate proposals against those objectives.

Recommendation 2

The CEAB recommends that the DPUC investigate whether DSM Focus case objectives can be reasonably met while minimizing Ratepayer/CEEF funding. The CEAB supports the DPUC's efforts to minimize delivery and administrative costs of DSM programs, such as through its review of incentives in Docket 07-10-03RE01.

The CEAB recognizes that ratepayer funded programs result in winners and losers in terms of the sharing of the benefits of the system savings (energy, capacity, and more). The degree to which rate impacts can be tolerated is an important consideration in determining whether the implementation of the full DSM Focus program levels is feasible. The CEAB's support for the DSM Focus objectives is coupled with support for the DPUC's efforts to balance near and long term rate and cost impacts.

Recommendation 3

There are several variables in the potential DSM Focus case implementation plans. Direct program plans incentives administrative cost structure, and program implementation timing all must be evaluated on an on-going basis. DPUC should determine the appropriate DSM Focus case implementation timeline, balancing the results of the Utility Cost Test and Total Resource Cost Test for cost-effectiveness with near term rate impacts.

The CEAB endorses the use of the Total Resource Cost Test to determine cost effectiveness. While the IRP states that the 2004 energy efficiency potential study assumes that all measures pass the Total Resource Cost test, the CEAB recommends continued detail review and optimization of the programs. The CEAB understands that the DPUC uses the Utility Cost Test and therefore suggests using both tests on a prospective basis.

1.3.6. Future Resource Planning Actions

RECOMMENDATION	
4.	Upon completion of the ECMB's 2008 DSM Potential Study, future Plans should provide a review of and possibly revisions to DSM Focus objectives.

Recommendation 4

Upon completion of the ECMB's 2008 DSM Potential Study, future Plans should provide a review of and possibly revisions to DSM Focus objectives.

The 2008 DSM potential study being conducted by the ECMB is near completion at the time of this writing. In addition to reviewing the energy efficiency potential, this study will identify demand reduction potential. This updated potential study will, no doubt, undergo careful review by the Distribution Utilities, the ECMB, the OCC, the DPUC, and others. The level of economic potential for DSM is dependent on the very dynamic level of avoided costs. The CEAB anticipates that changes to conditions such as avoided costs will be reflected in program plans and the overall DSM Focus objectives. Otherwise, the CEAB recommends the new DSM potential study be the basis for determining overall DSM Focus long term objectives in this and future Procurement Plans.

1.4. Renewable Energy Generation Recommendations

1.4.1. Procurement Plan Statutory Perspective

The Procurement Plan is required to consider the extent to which generation needs can be met by renewable and combined heat and power (CHP) facilities.[29] In addition, Section 51 lists several requirements closely related to renewable energy development: consideration of fuel diversity, stabilization of costs, and compliance with greenhouse gas and Clean Air Act goals.

1.4.2. Current Connecticut Programs and Policies

Connecticut supports renewable energy development through a number of methods.

CCEF: The Connecticut Clean Energy Fund (CCEF) receives funding from a ratepayer surcharge (at a level set by statute) to administer programs that support of renewable generation development, as well as research and development of emerging technologies.[30] The CCEF's Annual Comprehensive Plan, reviewed and approved by the DPUC, is required by statute to give preference to projects that reduce FMCCs.[31] The technologies eligible for CCEF support are set forth in statute and are not limited to Class I resources nor to in-state renewable resources.[32] The CCEF is required to use all ACP payments to invest in Class I renewable energy resources.

RPS: Connecticut requires all wholesale suppliers and all licensed electric suppliers to comply with the state's Renewable Portfolio Standard.[33] The RPS mandates that the total output of wholesale suppliers or electric suppliers must be not less than:

- A certain percentage be procured from Class I resources, graduating on an annual basis to a target of 20% by 2020;
- Three percent be procured from Class I or II resources by 2020; and
- Four percent from Class III resources by 2010.[34]

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29 See Connecticut General Statute Section 16a-3a(d).

30 See Connecticut General Statute Section 16-245n.

31 See Connecticut General Statute Section 16-245n(d).

32 See Connecticut General Statute Section 16-245n(a).

33 See Connecticut General Statute Sections 16-245(k) and 16-244c(j)(1).

34 See Connecticut General Statute Section 16-245a(a).

Class I includes resources such as wind, certain biomass, fuel cells, and solar.[35]

Class II includes trash-to-energy facilities, biomass facilities not included in Class I, and certain hydropower facilities.[36] Class III resources include energy efficiency measures and combined heat and power systems installed after January 1, 2006; and waste heat recovery systems installed after April 1, 2007.[37]

A primary means of meeting the RPS requirements is by purchasing Renewable Energy Certificates (RECs).[38] If wholesale suppliers or the electric suppliers cannot acquire RECs to meet Class I RPS requirements, they must make an Alternative Compliance Payment (ACP) for each megawatt hour they are short.[39]

Long Term REC Contracts: Beginning in 2008, Connecticut's electric distribution companies have authority to procure RECS from Class I, Class II, and Class III sources through long-term contracts. In a Draft Decision, the DPUC has tentatively concluded that the electric distribution companies must use these RECs to meet their standard service and supplier of last resort RPS requirements.[40]

Project 150: Connecticut supports the development of Class I renewable projects within Connecticut through a program commonly referred to as Project 150.[41] Project 150 requires the electric distribution companies to enter into long term contracts with 150 megawatts of renewable resources located in Connecticut. Following a competitive solicitation and evaluation by the CCEF and the electric

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35 See Connecticut General Statute Section 16-1(a)(26).

36 See Connecticut General Statute Section 16-1(a)(27).

37 See Connecticut General Statute Section 16-1(a)(44).

38 See Connecticut General Statute Section 16-245a(b).

39 See Connecticut General Statute Sections 16-245(k) and 16-244c(j)(1).

40 See Connecticut General Statute Section 16-245a(g) and DPUC Draft Decision in Docket No. 07-06-61, *DPUC Examination of Electric Distribution Company Contracts For Renewable Energy Certificates*, dated June 30, 2008. In a Draft Decision pertaining to long-term REC contracts, "[T]the Department has set forth some specific terms and some general guidelines for REC contract provisions. The Department allows, but does not require the electric distribution companies to procure REC contracts for new Class I resources. The Department will authorize a maximum of 0.4 mills per kilowatt hour as incentive compensation for long-term renewable energy certificates contracts. Any renewable energy certificates obtained pursuant to long-term contracts shall be used to meet their standard service and supplier of last resort renewable portfolio standard requirements. All costs associated with the long term renewable energy certificates contracts will be recovered through generation service charge rates." See Draft Decision Docket No. 07-06-61, *DPUC Examination of Electric Distribution Company Contracts For Renewable Energy Certificates*, dated June 30, 2008.

41 See Connecticut General Statute Section 16-244c(j)2.

distribution companies, the DPUC reviews and approves in-state renewable projects that merit long- term contracts. Projects can receive grants from the CCEF. The long-term contracts include a premium payment of up to 5.5 cents per kilowatt hour.

RGGI: Forthcoming RGGI regulations are expected to direct a portion (proposed to be up to 23%) of RGGI allowance auction proceeds to CCEF to develop Class I renewable resources.

There are currently several programs that also support Combined Heat and Power. They are:

Distributed Generation Grants: The DPUC administers programs for installing distributed generation (DG) that reduce FMCCs. These may be fossil fuel or renewable resources. The DPUC provides capital grants to customers who install distributed generation on their premise for their own power needs, provided the benefits outweigh the costs.[42] Grants are funded through FMCCs and collected from ratepayers. The grant value is higher for projects located in southwest Connecticut in light of congestion challenges in that area.

The electric distribution companies earn economic awards to educate, assist, and promote customer investment in these resources for installations that reduce FMCCs.[43] A low interest loan program is available for customer-side distributed resource projects.[44] The DG program also allows distributed resource projects that use natural gas to qualify for waiving certain gas distribution charges.[45] Finally, the electric cost associated with power used when base load customer-side generation is out of service can, in certain circumstances, be reduced by eliminating backup rates and demand ratchets.[46]

Class III RPS: The Class III RPS supports both energy efficiency and CHP.

1.4.3. Summary of the Distribution Utilities' IRP Findings

In their IRP, the Distribution Utilities examined the current state of Connecticut and regional energy generation development and, as a result, suggested re-examining the structure of the Renewable Portfolio Standard (RPS).[47] The IRP

[42] See Connecticut General Statute Section 16-243i(a).

[43] See Connecticut General Statute Section 16-243i(b).

[44] See Connecticut General Statute Section 16-243j.

[45] See Connecticut General Statute Section 16-243l.

[46] See Connecticut General Statute Section 16-243o.

[47] Finding #6 and in Recommendation 3

suggested that it was “beyond the scope of this study to estimate the future renewable energy development.”[48]

The IRP scenarios and resource solution cases were modeled assuming “no significant contribution of Class I resources to meet Connecticut RPS from resources physically located in Connecticut beyond the Project 100 capacity, {assuming} the full 150 megawatts of development.”[49]

The IRP offered three main renewables observations:

- There was likely a significant shortfall between the total New England RPS requirements and the Renewable Energy Credits (RECs) available from qualifying renewable energy generation projects. As a result, REC prices for total energy demand were equal to the alternate compliance payment (ACP) of $55 per megawatt hour.
- The cost of RECs at $55 per megawatt hour created annual costs to the consumers of about $200 million in 2011, growing to over $350 million by 2018 in some scenarios.
- The Distribution Utilities believed that the costs incurred did not generate renewable development because ACP was used for compliance.

1.4.4. CEAB Analysis and Observations

The public hearing revealed significant concerns about the Distribution Utilities’ RPS-related analysis and conclusions. In particular, the CCEF offered data showing that there are enough existing projects to meet regional and Connecticut RPS levels. In addition, the CCEF suggested that long term contracting was producing RECs at significantly lower prices to the buyers.

The CEAB assessed projections for developing the potential of regional renewable energy projects and determine the implications for the IRP and this Procurement Plan.

The CEAB held workshops with the Distribution Utilities, CCEF, and its consultant, and other stakeholders to discuss the potential for regional renewable development. In addition, the stakeholder group comprised principally of representatives of CCEF, the Distribution Utilities, DEP and CEAB agreed that it was reasonable to incorporate into the IRP a market overview and REC pricing analysis that showed the following:

- A surplus of resource potential exists to meet 2018 New England RPS total requirements.

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[48] page E-5 paragraph 3

[49] Appendix E Section IV page E-7

- The total of the current proposed projects meets 2018 New England RPS requirements.
- There is little potential for indigenous Connecticut resources to meet RPS requirements (as the IRP concluded).
- Long-term contracting for RECs or Energy Output and RECs should secure renewable energy at REC prices substantially below ACP (for example, $30 to $35 per megawatt hour rather than ACP of $55).
- An expected build-out of renewable energy generation facilities will likely include Canadian facilities exporting to New England.

See Appendix H: CEAB Review for Attaining Renewable Energy Targets for details of this analysis. This analysis suggests that adequate renewables in the region to enable Connecticut to meet the RPS.

1.4.5. Procurement Actions

RECOMMENDATIONS	
1.	A significant portion of the uncommitted standard service REC requirements for 2014 and beyond should be obtained through long term contracts to lower the overall cost of RPS and to assure the full development of the needed renewable resources.
2.	The DPUC should direct the EDCs, along with the CCEF, to create a pilot contract solicitation to allow the DPUC to evaluate the potential of contracting for bundled RECs, energy and capacity to further reduce REC costs.

Recommendation 1

As mentioned above, beginning this year, Connecticut's electric distribution companies have authority to procure RECs for their standard service and supplier of last resort renewable portfolio standard requirements through long-term contracting mechanisms.[50] The analysis produced during the stakeholder process shows why long-term contracting should result in REC prices substantially lower than the Alternative Compliance Payments (ACP).

The CEAB believes costs to consumers of complying with the RPS would be minimized by setting an objective to have the Distribution Utilities obtain RECS via the contracting mechanism beginning five years out. This will allow the time for development of new renewable projects to enter service. The $200 million – $350 million annual costs that the IRP identified as a potential cost to consumers could, potentially, be nearly cut in half via contracting, saving consumers hundreds of million dollars over time.

50 See DPUC Draft Decision in Docket No. 07-06-61.

The CEAB believes that an aggressive goal should be developed as a target for the amount of RECs that the Distribution Utilities should procure by 2014. The DPUC and the Distribution Utilities should evaluate whether it is too aggressive to have all the 2014 required RECs purchased under long term contracts.

Recommendation 2

In Draft Decision in Docket No. 07-06-61, the DPUC tentatively concludes that it is appropriate to possibly limit the utilities from contracting for energy and capacity in the context of REC contracts. In the CEAB's view, since the utilities have the authority to secure bilateral energy or capacity contracts[51] multiple objectives could be achieved by utilizing long term contracts with renewable facilities that procure bundled energy, capacity, and RECs produced by the facility as compared with REC contracting alone. The CEAB recommends that the DPUC direct the Distribution Utilities, in conjunction with the CCEF, to test the market through a pilot solicitation, to assess whether there are additional benefits in terms of energy price hedging or even lower REC prices from bundled contracting with renewable energy projects.

1.4.6. Future Resource Planning Actions

RECOMMENDATIONS	
3.	Additional analysis on CHP should be included in future Procurement Plans.
4.	Assess the economic potential renewable resource import options for Connecticut including consideration of nearby resources, northern New England, Canadian renewable resources, transmission projects and information from the ISO New England Economic Study.

Recommendation 3

The CEAB will investigate the potential for Combined Heat and Power (CHP) to allow future IRP analysis and Procurement Plans to determine how CHP can cost effectively meet resource needs.

Recommendation 4

The CEAB-sponsored regional renewable energy analysis (discussed in Appendix H) yielded a renewable resource build-out to satisfy the 2018 RPS requirements. Twenty percent of the 2018 RPS requirement is satisfied using renewable energy generation in Canada. ISO New England is studying the transmission implications of large scale renewable energy imports from Canada

[51] See DPUC Final Decisions in Docket No. 06-08-01RE01 and 07-06-58 dated April 2, 2008.

as well as increased renewable energy generation in northern New England. The CEAB recommends that future IRP analysis assess the potential resource size, the feasibility of additional transmission construction and the ultimate cost impacts to consumers of renewables from northern New England and Canada.

1.5. Connecticut Generation Recommendations

1.5.1. Procurement Plan Statutory Perspective

The Procurement Plan must specify the need for generating capacity. In addition, the Procurement Plan must consider optimizing generation sites as well as the generation portfolio existing within the state and the fuel types, diversity, availability, firmness of supply and security, and environmental impacts thereof, including impacts on meeting the state's greenhouse gas emission goals.[52]

1.5.2. Current Connecticut Programs and Policies

With some limited exceptions, Connecticut relies on the wholesale market to meet energy and capacity needs. Since 2000, Connecticut has procured, through Standard Service and Provider of Last Resort mechanisms, the generation service for utility customers who do not select a retail provider. The Distribution Utilities issue an RFP to select the lowest cost qualifying suppliers, with the oversight of the DPUC.

In response to concerns about adequate generating capacity, within the last three years, ISO New England has implemented two capacity related markets to procure resources and maintain reliability. The Forward Capacity Market for ICAP (or installed capacity) to maintain resource adequacy, and the Locational Forward Reserve Market for operable capacity or reserves, have stabilized the outlook for resources in the future. DSM opportunities can also participate in these markets further enhancing the market efficiency.[53]

In addition to market mechanisms, the DPUC has been directed by statute to procure certain conventional resources to meet specific objectives.

In 2005, the DPUC was directed to procure new capacity through a competitive process.[54] The objective was to decrease total costs of electricity for ratepayers over the next 15 years and to improve the reliability of the electricity system. The DPUC was authorized to approve contracts of 15 years or less that contain terms that mitigate the long-term risk assumed by ratepayers, and only if the contracts: 1) resulted in the lowest reasonable cost of such products and services; 2)

52 See Connecticut General Statute Sections 16a-3a(c) and 16a-3(d).

53 See IRP, Appendix A, sections III b and c.

54 See Connecticut General Statute Section 16-243m(c).

increased reliability; and 3) minimized FMCCs to the state over the life of the contract.

The three generation projects the DPUC selected reuse industrial sites and, in some cases, previous electric power generation sites. Potential bidders had to offer incremental capacity because the DPUC wanted to add rather than replace existing capacity. Repowering bidders had to pass one of two tests for retirement: formal declaration that the unit is retiring or economic evaluation of the unit demonstrating that it would face losses for three consecutive years.[55]

In 2007, the DPUC was directed by statute to solicit peaking generation plants.[56] Following a competitive process, the DPUC selected three peaking generators. Each project will be compensated at the plant's cost of service plus a reasonable rate of return; will be located on an existing generator site; and will be fired by natural gas.[57]

1.5.3. Summary of the Distribution Utilities' IRP Findings

Section 51 requires an assessment of resource availability within Connecticut over the next ten years. In the IRP, the Distribution Utilities' performed an economic analysis on the existing generation to determine if the ISO New England FCM would provide sufficient revenue to enable generators to remain economically viability. This analysis indicated that, since the revenues were greater than the going-forward costs, Connecticut generation was assumed to continue to operate throughout the study period.[58]

With planned levels of DSM, existing and planned new generation, and four distinct scenarios for future load growth; the IRP found no reliability-based need for new generating capacity in Connecticut over the next ten years.[59] The IRP incorporated four levels of cost impacts for CO_2 allowances applied to each of the four scenarios modeled. The IRP analysis assumed that the allowable levels for NO_x and SO_2 emissions remained at current levels.

1.5.4. CEAB Analysis and Observations

The CEAB held several stakeholder workshops on generation issues. Participants included generators, DEP, and Distribution Utilities. Highlights are as follows:

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[55] See DPUC Final Decision Docket No. 07-04-24, *DPUC Review of Energy Independence Act Capacity Contracts*, dated August 22, 2007, page 14.

[56] See Connecticut General Statute Section 16-243u.

[57] See DPUC Final Decision Docket No. 08-01-01, *DPUC Review of Peaking Generation Projects*, dated June 25, 2008.

[58] See the IRP, Appendix A, Section II for this analysis.

[59] See IRP Table 2.3.

- Generation owners and development companies expressed concerns about the assumption that no economic obsolescence-based retirements occur in the next ten years.
- When the existing oil and gas steam generation units need to invest in environmental controls (such as selective catalytic reduction (SCRs) units) to meet the likely emission rate limits, some 1,400 megawatts of Connecticut generation could retire due to insufficient revenue. This is a significant portion of the 2,400 megawatts of capacity
- The retirement of these 1,400 megawatts does not predicate the need for new generation inside Connecticut to meet local sourcing requirements. Local reliability concerns, however, could require new capacity to be built and acquired through the FCM or the LFRM.

In the stakeholder workshops, both DEP and the generators were concerned about the IRP conclusion that Connecticut generation would continue to operate throughout the study period. Representatives of Connecticut generators were concerned that the IRP analysis did not capture all the costs and risks associated with generating electricity in Connecticut. DEP discussed their need for and current efforts to implement revised emission regulations over the next ten years.

These regulations would when fully implemented greatly affect utility class boilers fueled by coal, oil and natural gas. These boilers would be required to cut their emission rates in half for SO_2 and NO_x. Retrofitting boilers with emissions controls would be a significant cost for each unit.

There is considerable overlap between the generation and emissions management discussions. For an extensive discussion of the emissions management analysis, see Appendix J: CEAB Review of Environmental Regulations.

The CEAB and the Distribution Utilities analyzed additional market simulations, incorporating tighter emissions regulations for NO_x and SO_2 and the resulting retrofit investments, unit retirements, and replacement. The retirements would alter the amount of new capacity resources that ISO New England would procure through its FCM. The modeling suggests that some of the new capacity resources required to meet regional reliability needs would likely be sited in Connecticut. The resulting resources in Connecticut would substantially reduce NO_x emissions — 30% during the summer ozone period and 60% on high demand days — without substantially changing the market clearing prices for capacity and energy.

The supplemental analysis, discussed in Section 2.3.2 and Appendix K, has not attempted to determine the type of capacity needed to replace any retired capacity. The CEAB considers the analysis of the retrofit projects required and the retrofit costs for environmental compliance to be very preliminary in nature. Additional analysis over additional scenarios is required to better estimate which generation units are most susceptible to retirement due to environmental regulations. After identifying generation units susceptible to retirement, analysis is required to determine if LFRM requirements and RMR-type requirements create a need for new resources. In the event that replacement capacity is needed in Connecticut, specific procurement by Connecticut may be needed to secure this capacity.

1.5.5. Procurement Actions

RECOMMENDATIONS

1. While the supplemental CEAB and Utility analysis establishes that a significant portion of existing Connecticut oil and gas steam capacity could retire over the next ten years, , the CEAB does not recommend the immediate solicitation of any replacement capacity within Connecticut.
2. Since the supplemental analysis indicates significant economic pressure on existing generation, the DSM, REC, and Bilateral Contracting resource acquisitions should be based on the assumption that some retirements occur.

Recommendation 1

The supplemental analysis shows that a substantial portion of existing Connecticut generation could become economically obsolete over the next ten years due in part to changing environmental regulations. While the CEAB recommends that Connecticut not immediately solicitat replacement capacity within Connecticut at this time, the CEAB believes it important to highlight the potential implications of future generation retirements.

While this does not necessarily trigger a need to add capacity resources within Connecticut to meet Forward Capacity Market (FCM) requirements, some of the new capacity resources required by the regional FCM may be sited in Connecticut. In addition, locational reserve requirements to meet local transmission security requirements have historically required more local capacity than the FCM. Local capacity replacements may be needed to meet these requirements.

The combined outcome of retirements, environmental retrofits and new capacity would not have any significant cost penalties for Connecticut consumers, based on what the analyses indicate at this time.

Recommendation 2

Recently it was assumed that no Connecticut resources would retire in the foreseeable future. If not for additional transmission that is planned, Connecticut would have been classified as a separate capacity zone.

Transmission congestion and reliability concerns indicated Southwest Connecticut was heading into a dangerously unreliable period, prior to the construction of new transmission capability. ISO New England, with FERC's authority, had classified much of Connecticut capacity as Reliability Must Run (RMR). Transitional capacity prices during the implementation of the FCM were high enough to sustain Connecticut capacity.

However, the first Forward Capacity Auction (FCA) of the FCM yielded low capacity prices and lots of demand-side management resources to compete with even the likely delisting or 'retirement' bids of existing generation. This coupled with a forward look at environmental regulations for NO_X and SO_2 and the potential costs to comply some capacity in Connecticut would find it uneconomic to continue operation.

Therefore, the CEAB recommends that when the DPUC evaluates procurement of DSM, renewable contracts, and new transmission projects that it factor in the implications of the retirement of some existing oil/natural gas steam capacity.

1.5.6. Future Resource Planning Actions

RECOMMENDATIONS	
3.	The utilities should complete the integration of evolving DEP emissions regulations and their impact on generation retirements into Procurement Plans.
4.	The DPUC should investigate the contracting process for repowering, retrofits, or long-term life extension from existing generation.
5.	The CEAB, in consultation with the Distribution Utilities, should conduct a targeted, fact-finding study to inform future consideration of nuclear power development.

Recommendation 3

The CEAB recommends that future IRP and procurement plans be based on analysis that incorporates a much finer look at the retirement question. This retirement analysis should capture more direct input from the DEP regarding the potential for future environmental regulations.

The supplemental analysis conducted in collaboration by the Distribution Utilities and the CEAB only begins the required analysis. For example, this analysis was produced for only one year, 2018, and for only one of the four scenarios. The CEAB believes there is significant merit for future IRP analysis to capture the dynamics of emissions regulation and the life expectancy of older generation.

Stakeholder discussions underscored that there are many options for older generators other than retirement. These units could be reconfigured with retrofits to be cleaner and more efficient, or repowered into combined cycle capacity. Retirements, retrofits, or repowering could create unique timing challenges to implement this plan. The state should ensure it has contracting authorities and processes to capitalize on the strategic and economic value of existing generation or existing sites.

Recommendation 4

This 2008 Procurement Plan does not recommend the construction of any generation facility. However, the risk of retirements may lead to the identification of need for new or repowered generation facilities in subsequent planning cycles. The DPUC should investigate the contracting process involving repowering, retrofit, or long-term life extension from existing generation.

Section 52(b) sets forth requirements for a DPUC request for proposals process in the event that the Procurement Plan specifies the construction of a generation facility.[60] Historically, the DPUC has established the framework of solicitations for new generation sources in advance of issuing an RFP for specific resources. The CEAB believes that establishing the process through which the DPUC would execute generation procurement pursuant to Section 52 would provide the market clarity on implementation issues.

The DPUC should consider mechanisms for life extension and repowering in the contracting process, consistent with the Section 51 requirement to optimize the use of generation sites and the existing state generation portfolio.[61] The stakeholder workshops identified the potential emissions control investment requirements for Connecticut's older oil and gas fired steam units during the planning period. Repowering existing units or reusing existing sites are also options which should be explored during the contracting process. The issues of retirement, life extension, and repowering represent both risk of lost capacity and opportunities for new capacity development in Connecticut. Procurement activities under Section 52(b) should be prepared to accommodate consideration of these issues.

Recommendation 5

Any discussion about the potential for a nuclear option presents a host of complex issues. To inform future consideration of the potential for additional nuclear power in the resource mix, a targeted, fact-finding study should be conducted by CEAB in consultation with the Distribution Utilities.

[60] See Connecticut General Statute Section 16a-3b(b).

[61] See Connecticut General Statute Section 16a-3a(d)(3).

Interest in the potential for new nuclear power development stems from the need to decrease dependence on fossil fuel, increase energy independence, and help meet environmental goals through carbon-free generation resources. At the same time, the prospects for nuclear energy as an option may be limited by issues such as: high costs; perceived adverse safety, environmental, and health effects; potential security risks; and, unresolved long-term management of nuclear waste.

A study should provide a factual foundation on current nuclear issues to inform future discussions. To be clear, the study would not result in recommendations of any sort but rather provide information and data on issues such as: international developments; current domestic development activities; entities involved with construction and potential ownership and operation; technologies; safety data; cost estimates; regulatory requirements; and siting needs.

1.6. Transmission Related Recommendations

1.6.1. Procurement Plan Statutory Perspective

The Procurement Plan must specify the need for transmission and distribution improvements.[62]

1.6.2. Current Connecticut Programs and Policies

Approving new transmission facilities in Connecticut involves two processes: the CEAB's Request for Proposal and the Siting Council's certification of need. As contemplated by statute, the CEAB issues an RFP for alternatives to a transmission project that has applied for a Certificate of Need. The CEAB evaluates and compares the proposed alternatives and the transmission project for consistency with infrastructure criteria guidelines (referred to as Preferential Criteria).[63] The CEAB then sends to the Siting Council a report that provides a comparative analysis of all projects. The Siting Council considers the CEAB's comparative analysis and must find that the proposed project represents the most appropriate alternative presented.

The CEAB can, however, exempt a transmission project from an RFP if it determines that a reasonable alternative to the proposed facility is not likely to result from the process.[64] In this case, the Siting Council considers the transmission project and makes specific findings before approving a project (known as issuing a certificate of need). Those findings include, but are not limited to: the facility is necessary; the facility will not pose a safety hazard; and the facility will not materially decrease acreage and productivity of arable land. Any adverse environmental impacts, or conflicts with environmental or natural resource policies are not reason to deny the project.[65]

1.6.3. Summary of the Distribution Utilities' IRP Findings

The IRP addressed transmission upgrade projects in a limited manner. In IRP Section IC Limitations, the Distribution Utilities clarify that the "study was not intended to provide a cost/benefit analysis of transmission options; did not

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[62] See Connecticut General Statute Section 16a-3a(c).

[63] See Connecticut General Statute Section 16a-7b.

[64] See Connecticut General Statute Section 16a-7c(b).

[65] See Connecticut General Statute Section 16-50p.

compare the economics of transmission vs. generation or vs. demand-side options; and does not constitute a transmission reliability assessment."[66]

The IRP described in detail the assumptions regarding the transmission system, principally the proposed New England East-West Solution (NEEWS) transmission project.[67] The Central Connecticut Reliability Project component of NEEWS was included in the analysis as a sensitivity.

1.6.4. CEAB Analysis and Observations

The CEAB, the Distribution Utilities, ISO New England, and others participated in a transmission stakeholders workshop. The highlights are as follows:

- Discussion confirmed that the NEEWS Needs Assessment & Options Analysis Report, prepared by ISO New England, National Grid and Northeast Utilities, focused on transmission solutions. No organization is or plans to evaluate whether any combination of generation capacity additions and/or demand reductions could change the need for or timing of any of the transmission projects in NEEWS.
- ISO New England presented an overview of its FCA1 process. This included the consultation on the need for Connecticut generation units if delisting bids were forthcoming. This process resulted in the Norwalk Harbor capacity remaining as RMR for 2010.
- ISO New England provided clarity on the LFRM & daily second contingency dispatch requirements. This helped the CEAB understand that the IRP analysis was thorough.
- ISO New England explained its plans to conduct studies on the transmission requirements to support the regional renewable energy generation build-out.
- Discussions clarified that Connecticut would not be considered a capacity zone with the NEEWS projects.

Not integrating transmission projects into the IRP analysis is a lost opportunity to analyze some alternatives to transmission. For example, Northeast Utilities (NU) has not performed any Non-Transmission Alternative (NTA) analyses for the proposed NEEWS projects and does not appear to have plans to conduct such analysis for any portion of it. Thus, how reductions in demand growth and the addition of new generation in specific locations would influence the need for or timing of transmission projects is not known. These questions are especially relevant given that: 1) DSM Focus would eliminate load growth, and 2) the recent approvals of nearly 700 megawatts of peakers and the prior 1,460

[66] See IRP, page 2.

[67] See IRP, Appendix A and particularly Appendix G, Section XVI.

megawatts of DPUC-sponsored new capacity contracts will add location-preferred generation.

1.6.5. Procurement Actions

RECOMMENDATION	
1.	The CEAB will be reviewing alternative solution analysis of the NEEWS project either via the reactive RFP process triggered by Siting Council filing or via alternative analysis proffered to support an exemption.

Recommendation 1

Additional work is needed to address the integration of transmission planning into the procurement planning process. Section 51's direction to identify the needs for transmission and to review demand side resources on an equitable basis with non-demand-side resources remain an important objective in the planning process.

The beginning of the permitting process for the NEEWS transmission project provides one avenue for the further assessment of the integration of transmission planning with planning for generation and demand resources. NU has provided municipal notice on the Greater Springfield portion of the NEEWS project, which includes some transmission facilities in Connecticut. Other projects within NEEWS will follow. The CEAB will be reviewing these projects through an RFP process for alternative solutions or alternative analysis proffered to support an exemption. This process offers CEAB and NU the opportunity to work collaboratively to consider mechanisms to better integrate transmission considerations into the procurement planning process. The CEAB recommends that the collaborative process integrate transmission planning with other ideas from this Procurement Plan including the potential of eliminating load growth through DSM, potential for generation retirements and potential growth of renewable resources in New England.

1.6.6. Future Resource Planning Actions

RECOMMENDATION	
2.	Future Procurement Plans should include Non-Transmission Alternatives (NTA) and economic benefits assessments for all proposed significant transmission projects.

Recommendation 2

In light of the CEAB's and the Siting Council's requirement to consider alternatives to transmission during the permitting process, the procurement planning process is an ideal vehicle through which to explore non-transmission alternative solutions to needs. This analysis should only address alternatives to transmission that meet the same needs, including reliability. Vermont and Maine's process to assess non-transmission alternatives may be useful models.

The CEAB recommends that future procurement plans include a non-transmission analysis and economic benefit assessments for all significant proposed transmission projects. Reductions in demand growth and the addition of new generation in specific locations could influence the need for or timing of transmission projects. This is an especially relevant question considering that: 1) DSM Focus would eliminate load growth, and 2) the recent approvals of nearly 700 megawatts of peakers and the prior 1,460 megawatts of DPUC-sponsored new capacity contracts will add location-preferred generation.

1.7. Emissions Management Recommendations

1.7.1. Procurement Plan Statutory Perspective

The Department of Environmental Protection (DEP) is the primary environmental and natural resource management agency in the state. It has state and federally conferred jurisdiction over preservation and protection of air, water, and other natural resources in the state. Thus, the DEP sets standards for and regulates air emissions, water discharges and diversions, waste management, and certain land uses and remediation. The DEP is charged with implementing RGGI and administering allowance auction proceeds.

The Procurement Plan must address the impact of current and projected environmental standards including, but not limited to, greenhouse gas emissions, the federal Clean Air Act goals, and how different resources could help achieve those standards and goals.[68]

1.7.2. Current Connecticut Programs and Policies

The DEP is currently evaluating emission reduction strategies for all stationary sources of NO_x and SO_2. This is part of an overall state effort to implement emission reduction strategies that can help Connecticut attain the National Ambient Air Quality Standards (NAAQS), especially on "high electric demand" days.

In addition, the Clean Air Interstate Rule (CAIR)[69], which is to be implemented in 2009, establishes a statewide ozone season budget.

The Procurement Plan must address and satisfied the carbon requirements of Section 22a-200c(d).

1.7.3. Summary of the Distribution Utilities' IRP Findings

The IRP partially addressed future environmental standards by incorporating different levels of carbon emissions allowance costs within the scenario analysis process. The analysis assumed no changes over time to the current regulations governing NO_x and SO_2 emissions or toxins such as mercury.

68 See IRP, Section 51.

69 Environmental Protection Agency's CAIR was invalidated by a Federal Appeals court on July 11. While this creates uncertainty in the emissions regulation framework it does not abate the need to achieve the federal standards.

The Connecticut Department of Environmental Protection (DEP) is in the midst of evaluating emission reduction strategies for all stationary sources of NO_x. This is part of an overall state effort to implement emission reduction strategies that can help Connecticut reach attainment with the NAAQS, especially on “high electric demand” days.

Since the Distribution Utilities’ analysis did not account for tighter NO_x and SO_2 regulations, the going-forward costs of older Connecticut oil/gas steam generation remained low and thus no retirements were warranted. The initial plan did not adequately consider retirements or retrofits for environmental controls and current efforts to reduce emissions, especially of pollutants such as NO_x that can dramatically impact ozone levels.

1.7.4. CEAB Analysis and Observations

The CEAB’s review of the evolving environmental requirements included a high-level evaluation of environmental considerations related to: global climate change, attainment of federal ambient air quality standards, and some consideration of localized impacts from toxic pollutants such as mercury. It is important to highlight the dynamic nature of environmental requirements, especially on the federal level which continuously impact regulatory requirements and program implementation on the state level.

Connecticut is currently implementing a suite of emission reduction strategies targeting a wide-range of sectors in the state, including electric-generating units. Even with the implementation of the full complement of strategies currently under consideration, current modeling does not project attainment of the federal health-based standards by 2020.

The CEAB held stakeholder workshops focused on bringing the potential tighter DEP regulation levels into the IRP analysis. Participants included the utilities, DEP, the generation companies and Environment Northeast. Highlights are as follows:

- DEP emissions management objectives are generally separate from electric resource planning and acquisition initiatives, ECMB programs, Project 150, transmission planning, and capacity contracting.
- Clean air goals and objectives can be furthered by continually integrating energy and air quality planning, emissions controls, and electric resource choices.
- Investing in emission controls and retiring or replacing current generation with more efficient generation could increase in-state generation output. Replacements that comply with air quality emission standards combined with retirements will likely reduce summer ozone period emissions significantly

and dramatically eliminate the problematic “high-electric demand” day emissions in the state.

Within the Stakeholder Input Workshops DEP discussed their need for and current efforts to implement revised emission regulations over the next ten years. These regulations would when fully implemented greatly affect utility class boilers fueled by coal, oil and natural gas. These boilers would be required to cut their emission rates in half for SO_2 and NO_x. These older units possess some of the highest emissions rates of NO_x per megawatt compared to other capacity resources. These older units operate to provide operating reserves and to provide peaking capacity, primarily operating within the summer ozone period and especially during high energy demand days that often produce the poorest air quality measured in the State.

DEP identified the challenges regarding the state’s ability to meet the National Ambient Air Quality Standard (NAAQS) for ozone with the emissions profile of the older oil/natural gas steam capacity in Connecticut. As part of a regional effort within the Ozone Transport Commission region, the DEP is evaluating emission reduction targets that can help Connecticut achieve compliance with the NAAQS. From the additional analysis provided by the Distribution Utilities in this iteration of the plan, emission reduction targets designed to achieve the NAAQS will necessitate investments in environmental controls for ‘older’ steam capacity.

For a larger discussion of managing emissions, read Appendix J: CEAB Review of Environmental Regulations.

1.7.5. Procurement Actions

RECOMMENDATION	
1.	Resource acquisitions should be evaluated to include more stringent emission limits in future regulations. These could include greenhouse gases such as carbon dioxide, criteria pollutants such as NO_x or SO_2, and toxic pollutants such as mercury.

Recommendation 1

Knowledge of the likely adoption of more stringent environmental regulations is necessary to predict and evaluate resources. The future will likely bring some reductions to the allowable emission rates for oil and natural gas-fired boilers. Resource acquisition should be evaluated to include more stringent emissions regulations. These could include greenhouse gases such as carbon dioxide, criteria pollutants such as NO_x, or SO_2, and toxic pollutants such as mercury.

Accordingly, the procurement analysis in subsequent planning cycles should consider at least some cases with more stringent environmental emissions regulations on all air pollutants. The CEAB recommends analysis of cases where allowed emissions rates are reduced significantly over the next ten years.

1.7.6. Future Resource Planning Actions

RECOMMENDATIONS	
2.	More thorough and current estimates of the necessary environmental retrofits and their costs should be included in Procurement Plans.
3.	Future Procurement Plans should provide additional information that can be included in the base information when the DEP considers the impact of its changes to air quality regulations.

Recommendation 2

The CEAB and the utilities started supplemental modeling analyses using generic needs for environmental retrofit projects at Connecticut generation facilities. Environmental compliance staff at NRG provided information specifying which retrofit technologies would be required to meet the DEP emission limits. The cost estimates for these retrofits were developed from a 2003 report by the Northeast States for Coordinated Air Use Management and may be dated.[70]

The CEAB recommends that the utilities continue this analysis in future IRP work and deploy resources to develop more accurate estimates of retrofit costs. This information will be useful in future plans.

Recommendation 3

The CEAB notes the IRP analysis can be very useful to the DEP in understanding potential impacts from changes in emissions regulations. This can be particularly effective if the utilities employ some continuation of the stakeholder input process that the CEAB utilized over the past three months.

The CEAB recommends that in conducting future IRP analysis the Distribution Utilities consult with DEP on both pending regulations and to understand what comparisons, metrics and output can be helpful to the DEP as they move forward in evolving regulations decisions.

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[70] Northeast States for Coordinated Air Use Management, "Assessment of Control Technologies for BART-Eligible Sources". March 2005.

2. CEAB ACTION PLAN DEVELOPMENT AND PUBLIC PROCESS

2.1 Statutory Requirements Guiding the Procurement Plan

Section 51 of Public Act 07-242, *An Act Concerning Electricity and Energy Efficiency*, requires the state's electric distribution utilities (Connecticut Light & Power and United Illuminating) to annually review the state's energy and capacity resource assessment and develop a resource plan. The first such assessment was to be submitted to the CEAB for its review by January 1, 2008.

The CEAB is required to review, modify as appropriate and approve the plan. Its review must include consultation with ISO New England and a public hearing. The CEAB must forward an approved plan, along with a statement of unresolved issues, to the Department of Public Utility Control (DPUC) for its consideration.

The general point of Section 51 is a plan that provides a sound assessment of the resource needs and a set of strategies and recommended actions.

Section 52 outlines the DPUC's responsibilities with regard to the implementation of the Procurement Plan.[71]

[71] See Appendix A for the complete text of the Sections 51 and 52.

2.2 Response and Review of the Distribution Utilities IRP and CEAB

Schedule Incorporated for 2008	
January 1	CL&P and UI delivered their Integrated Resource Plan (IRP) to the CEAB on.[72]
January 4	The Distribution Utilities presented an overview of the IRP to the CEAB.
January 11	The CEAB issued a request for public comment.
January 28	CEAB's consultants provided the CEAB with initial findings on an assessment of the IRP compared to legislative requirements.[73]
February 8	The Distribution Utilities jointly reached out to the board in a letter offering cooperation in finalizing a plan for submittal to DPUC in light of findings and comments.[74]
February 11	The CEAB held a public hearing in the Legislative Office Building in Hartford.[75]
February 21	The CEAB's consultant issued a process report identifying the steps needed to meet the legislative requirements of the Procurement Plan, including gathering more information, conducting additional analyses, integrating the results into a Procurement Plan and outlining the scope of future Plans.[76]
March 7	The CEAB wrote to the chairs of the Energy and Technology Committee of the legislature informing them of the status and the planned process going-forward to complete the plan.[77]
March 7	The CEAB issued a Status Report on its review of the Distribution Utilities' IRP and included a summary of the public input.[78]
April–June	Twelve stakeholder input workshops.
June 6	The CEAB issued a Status Report at the conclusion of the Stakeholder Input Process.
July–August	Supplemental modeling analysis.

72 See http://www.ctenergy.org/pdf/REVIRP.pdf

73 See http://www.ctenergy.org/pdf/ProcurementRpt.pdf

74 See http://www.ctenergy.org/pdf/Utility.pdf

75 The transcript is available at http://www.ctenergy.org/pdf/ProcurementTranscript.pdf

76 See http://www.ctenergy.org/pdf/IRPprocessFINAL.pdf

77 See http://www.ctenergy.org/pdf/etltr.pdf

[Was it at this time that a schedule change was requested? If so, should we say that?]

78 See http://www.ctenergy.org/pdf/IRPstatusFinal.pdf

More than a dozen people spoke at the public hearing. Most of them also submitted written comments. In total, twenty (20) entities submitted written comments on all or parts of the IRP and forty (40) individuals submitted e-mails.[79]

Appendix E: Status Report: Conclusion of Stakeholder Input Process contains a high level summary of the public comments received by the CEAB, organized by subject matter.

2.3 Utilities and CEAB Collaborative Efforts

2.3.1 Stakeholder Input Workshops

As part of its collaborative effort, the Distribution Utilities and the CEAB held a series of twelve Stakeholder Input Workshops focusing on DSM, renewable energy, generation, transmission, and environmental compliance. These workshops were attended by representatives of some 16 different entities. In addition, CEAB consultants and the Distribution Utilities' representatives had numerous phone calls with stakeholders to inform them of the Procurement Plan development and to solicit comments.

Appendix E: Status Report: Conclusion of Stakeholder Input Process describes the workshops and includes an overview of what was presented, key input, and participating organizations.[80]

2.3.2 Supplemental Analysis

The IRP included analytical modeling sponsored by the Distribution Utilities, conducted by The Brattle Group. Four scenarios were modeled: Current Trends, Strict Climate, High Fuel, and Low Stress. Each scenario was then solved for four cases: conventional fuel, coal, nuclear, and DSM Focus. Four years were studied for each scenario and case: 2011, 2013, 2018, and 2030. The output of the modeling included energy and capacity prices, electric demand, environmental emissions, reliability, cost to Connecticut customers, and other relevant factors.[81]

After holding the Stakeholder Input Workshops, the Distribution Utilities sponsored follow-up model runs, again conducted by The Brattle Group. These

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[79] See http://www.ctenergy.org/Procurement_Plan_Review.html and Appendix D.

[80] See also http://www.ctenergy.org/pdf/MayProcRpt.pdf.

[81] For more details on this analytical modeling, see Appendix K.

model runs incorporated new data made available during the Stakeholder Input Workshops.

The time available for the supplemental analysis was limited. The Distribution Utilities' and CEAB consultants concluded that it was most productive to focus on producing an Enhanced Base Case under the Current Trends scenario and only for the year 2018, allowing the work to incorporate information from the stakeholder workshop processes. Specifically, the following information was incorporated into the model run:

- Renewable build-out to meet the 2018 RPS requirement: The Renewables Stakeholder Workshop yielded a renewable build-out to meet the 2018 RPS requirements in New England.
- NO_x emission limits proposed for stakeholder discussions: The Environmental Emissions Stakeholder Workshop yielded indepth discussions on proposed emissions limits for 2018 and the emissions controls that existing facilities needed to meet those regulations. An analysis was conducted based upon emissions control upgrade costs to determine if facilities not meeting the new regulations would upgrade their emissions controls or retire.
- Some 1,400 megawatts of Connecticut oil and gas steam capacity would potentially retire if required to make environmental retrofits of the magnitude modeled (SCR and Scrubbers).

The model run was based on the Current Trends scenario and the DSM Focus case for the year 2018. The modeling began with the DSM Focus case and added the renewable build-out, allowing observations to be made on the impact of the renewables. The next step incorporated the tighter emissions regulations and the resulting retrofit investments, retirements, and replacement capacity. This allows observations regarding the cost of emissions abatement.

One additional model run was conducted incorporating nuclear capacity in Connecticut. This new Enhanced DSM Focus case examined the impacts on regional and Connecticut emissions levels when all cost-effective DSM is implemented, when the RPS requirements for the regional are met at lower costs than ACP, and when regulations tighten for NO_x and SO_2 emissions.

Some key observations are as follows:

- Investing in renewables to meet RPS targets is cheaper system-wide than not investing and paying the ACP price, assuming that the amounts of renewables projects that the CEAB analysis estimates can actually be developed at the costs assumed.

- None of the SCR and Scrubber investments pay for themselves based on allowance savings alone, so they would not likely occur without more stringent regulations.
- SCRs and Scrubbers on coal units reduce NO_x and SO_2 emissions far more than control on oil-fired steam units, and at a much lower cost per ton (both overall and during peak days).
- Nuclear baseload could provide CO_2 abatement at a cost lower than renewables if nuclear facilities could be developed at the costs assumed in the IRP analysis. Both are more expensive than the CO_2 allowance price of $13 in 2018 (all 2008 dollars).

See Appendix H: CEAB Review for Attaining Renewable Energy Targets for a more detailed description of CEAB observations and implications of this analysis. In addition, the Distribution Utilities will most likely be filing a report from The Brattle Group documenting this supplemental collaborative analysis.

3. COMPILATION OF RECOMMENDATIONS

All of the recommendations set forth in Section 1: Action Plan are compiled and organized here by procurement recommendations and by resource planning and future planning recommendations for convenience of the reader.

3.1 Procurement Recommendations

1. The immediate focus of resource acquisition procurement actions should be demand-side management and renewable energy credits.
2. The IRP supports the potential benefits of bilateral contracting as a means to stabilize and/or reduce standard service rates. Consider combining bilateral and REC contracting.
3. No other resource acquisition procurement activities are recommended in this 2008 Procurement Plan.
4. The IRP supports adopting demand response (DR) and energy efficiency (EE) program levels as defined in the DSM focus case as the 3–5 year objective.
5. The DPUC should investigate whether DSM Focus case objectives can be reasonably met in a cost effective manner compared to generation and transmission while minimizing ratepayer and CEEF funding, and avoiding potentially more costly investments in new generation and transmission.
6. The DPUC should determine the appropriate ramping up for DSM Focus, balancing the results of the Utility Cost Test and Total Resource Cost Test for cost-effectiveness with near term rate impacts.
7. A significant portion of the uncommitted standard service REC requirements for 2014 and beyond should be obtained through long term contracts to lower the

overall cost of RPS and to assure the full development of the needed renewable resources.

8. The DPUC should direct the EDCs, along with the CCEF, to create a pilot contract solicitation to allow the DPUC to evaluate the potential of contracting for bundled RECs, energy and capacity to further reduce REC costs.
9. While the supplemental CEAB and Utility analysis establishes that a significant portion of existing Connecticut oil and gas steam capacity could retire over the next ten years, the CEAB does not recommend the immediate solicitation of any replacement capacity within Connecticut.
10. Since the supplemental analysis indicates significant economic pressure on existing generation, the DSM, REC, and Bilateral Contracting resource acquisitions should be based on the assumption that some retirements occur.
11. The CEAB will be reviewing alternative solution analysis of the NEEWS project either via the reactive RFP process triggered by Siting Council filing or via alternative analysis proffered to support an exemption.
12. Resource acquisitions should be evaluated to include more stringent emission limits in future regulations. These could include greenhouse gases such as carbon dioxide, criteria pollutants such as NO_x, orSO_2, and toxic pollutants such as mercury.

3.2 Resource Planning and Future Planning Recommendations

1. The DPUC should consider establishing the generation procurement framework under Section 52 in advance of future plans that may counsel construction of new generation.
2. Upon completion of the ECMB's 2008 DSM Potential Study, future Plans should provide a review of and possibly revisions to DSM Focus objectives.
3. Additional analysis on CHP should be included in future Procurement Plans.
4. Assess the economic potential renewable resource import options for Connecticut including consideration of nearby resources, northern New England, Canadian renewable resources, transmission projects and information from the ISO New England Economic Study.
5. The utilities should complete the integration of evolving DEP emissions regulations and their impact on generation retirements into Procurement Plans.
6. The DPUC should investigate the contracting process for repowering, retrofits, or long term life extension from existing generation.
7. The CEAB and the Distribution Utilities should jointly conduct a study on all the issues surrounding nuclear power development.
8. Future Procurement Plans should include Non-Transmission Alternatives (NTA) and economic benefits assessments for all proposed significant transmission projects.
9. More thorough and current estimates of the necessary environmental retrofits and their costs should be included in Procurement Plans.
10. Future Procurement Plans should provide additional information that can be included in the base information when the DEP considers the impact of its changes to air quality regulations.

4. GUIDELINES FOR 2009 PLAN AND FUTURE PROCUREMENT PLANS

4.1 The Procurement Plan 2009 Update

Section 51 established an annual planning cycle, with each cycle beginning with the Distribution Utilities' January 1, 2008 submission to the CEAB, followed by CEAB's review, modification as appropriate, and approval of the Procurement Plan, and the DPUC's review, modification as appropriate, and approval of the Procurement Plan for implementation.

In 2008, the initial planning cycle was highly productive but demonstrated that work remains to develop the planning process to fully address the requirements of Section 51 and to address key issues identified in this first planning cycle. In addition, this first planning cycle has required more time than contemplated in Section 51, leaving the distribution companies with limited time (five months from the date of this CEAB Procurement Plan), to develop their January 1, 2009 Procurement Plan report.

It is the CEAB's view that the distribution utilities January 1, 2009 report should, focus on:

- A complete supplemental analysis recommended by CEAB during the collaboration process as discussed in Section 2.3.2 and Appendix K.
- An update regarding any material changes in assumptions that would affect the validity of any analysis provided in the 2008 Procurement Planning Process.
- Any report on new material or information regarding resource options, should include DSM, renewables, CHP, and existing Connecticut generation.

- A proposed work plan for the January 1, 2010 Procurement Plan report should include, to the extent possible, any issues and directives arising from the DPUC review and approval of the 2008 Procurement Plan.

4.2 Future Planning

In this section, the CEAB outlines several areas where future IRP analyses and Procurement Plans can be enhanced to better support decision making for Connecticut. Many of these recommendations were discussed in earlier sections.

It is evident from the current resource procurement activities and the IRP that there should be multiple objectives for future Procurement Plans. The Plans should identify resource objectives to be immediately procured, as needed, in some form by Connecticut. The Plans should also provide context and overall objectives for Connecticut in terms of a target for the appropriate mix of resources. Once approved by the DPUC these objectives should guide all resource procurement activities.

The CEAB understands the very limited period of time that the Distribution Utilities have to prepare the 2009 IRP. As such, while if would be ideal if the guidelines below are incorporated as quickly as possible, capturing many of these within the 2009 plan may not be practical. The CEAB proposes the following guidelines for additional analyses for the 2009 and future procurement plans:

1. Future Procurement Plans should incorporate some aspects of risk analysis and an optimization of resource mix.

   The incorporation of scenario analysis into the IRP is an excellent way to recognize the uncertainties in the energy world. In order to test the robustness of the Procurement Plan's recommendations some consideration of the risks imposed from the resource plan must be addressed. Risks can be market price uncertainty, technical performance of resources, environmental regulations or risks to system reliability. Analysis should lead to a recommendation of the optimum resource mix. There are specific planning techniques and programs that perform optimization. The CEAB is not recommending a specific technique but urges that IRP analysis investigate enough resource plan options to arrive at a recommendation for the optimum resource mix.

2. Future Procurement Plans should specifically analyze the cost and potential benefits of the following supply resources.

   It is especially timely to analyze several specific resource options there are getting public policy makers attention. The CEAB urges that the following options be investigated and evaluated in the IRP to determine if procurement actions are necessary. If so, several of these resource options will likely require special intervention into the market by the utilities or the State:

- Import of renewables and nuclear power from Canada, particular including the transmission requirements and their costs.
- Combined Heat and Power potential – small scale and grid-connected projects.
- Connecticut and Domestic sited additional nuclear capacity.
- Connecticut and regional potential for advanced / clean coal generation with or without carbon sequestration.

3. Future Procurement Plans should determine the impact from emerging technologies such as plug-in hybrid vehicles on electric energy requirements, and the resulting emissions.

   There is a growing concern that major market fluctuations occurring within the global energy world could establish price levels currently considered highly improbable if not impossible. Such changes will result in technology responses and possibly even major changes in where Americans live, where they work and how they drive. It is important that future plans address the longer term effects of any trends beyond the 10 year procurement plan legislated horizon.

4. Future Procurement Plans should consider their impact on ‘energy security’.

   The first step in most electric resource planning analyses is to make sure a plan meets reliability standards in order for it to be considered. The IRP contains and the procurement plan requires such a resource adequacy assessment. In today’s environment there is another step required, possibly the final step, an assessment of the resource plans ability to provide energy security. Plans need to address the systems vulnerability to natural disasters, technological failures and terrorist attacks. Plans we ultimately need to provide an adequate level of security in addition to basic system reliability.

5. ACTION ITEMS

The following is a list of actionable items by entity that relate directly to the CEAB's recommendations. The actions listed here are reflected in Section 1: Action Plan, and are compiled in this format for the convenience of the reader.

CCEF

CCEF should be responsible for the following action items:

- Support the distribution utilities in the long term contracting for RECs.
- Support a pilot study to determine if there are benefits of bundled long term REC, capacity and energy contracts verses long term REC contracts along.

CEAB

The CEAB should be responsible for the following action items:

- Conduct a CHP potential study regarding smaller facilities and use the study as a foundation to evaluate CHP in future Procurement Plans.
- Review the alternative solution analysis of the NEEWS project either via the reactive RFP process triggered by Siting Council filing or via alternative analysis proffered to support an exemption.
- Work jointly with the Distribution Utilities to conduct a comprehensive study of nuclear generation issues.

ECMB

ECMB should be responsible for the following action items:

- Administer current and/or expanded DSM programs to meet expanded DSM goals.
- Study means beyond current programs to meet DSM goals including appliance efficiency standards, building codes, etc.

- Develop, with the Distribution Utilities, the plan for DPUC approval to meet DSM objectives described in plan given information developed in the 2008 DSM potential study.

Distribution Utilities

The Distribution Utilities should be responsible for the following action items:

- Develop, with the ECMB, the plan for DPUC approval to meet DSM objectives described in plan given information developed in the 2008 DSM potential study.
- Test the market for combined bilateral contracting of power with REC contracts to determine if renewable energy, price stability and cost reduction objectives can be met with this approach.
- Assess the retirement risks associated with existing fossil steam units in Connecticut.
- Procure RECs utilizing the long term contracting authority granted by the DPUC.
- Determine the optimal percentage of RECs to be procured under long term contracts.
- In the future IRPs, assess the economic potential renewable resource import options for Connecticut including consideration of nearby resources, northern New England, Canadian renewable resources, transmission projects and information from the ISO New England Economic Study.
- Work jointly with the CEAB to conduct a comprehensive study of nuclear generation issues.
- Complete the integration of evolving DEP emissions regulations and their impact on generation retirements into Procurement Plans.
- In future IPR analyses, consider at least some cases with more stringent environmental emissions regulations on all air pollutants.
- Continue analysis on estimates of future environmental retrofits and their costs.
- Consult with DEP on pending regulations and modeling output and metrics which would be helpful to DEP.

DEP

DEP should support the development of future procurement plans:

- Work with the Distribution Utilities to assure that the IRP analysis can capture the evolution of environmental regulations under consideration.
- Incorporate IRP output and Procurement Plan recommendations into its internal processes when evaluating the impacts of potential changes in regulation.

GLOSSARY

ACP
Alternative Compliance Payment is a payment of a certain dollar amount per megawatt-hour, which a Retail Electricity Supplier or Electric Distribution Company wholesale supplier may submit in lieu of supplying the minimum percentage of renewable energy required under Renewable Portfolio Standards.

Baseload
The minimum amount of electric power delivered or required over a given period of time at a steady rate.

Capacity
The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Carbon Sequestration
This process involves the injection of carbon dioxide, generally in supercritical form, directly into underground geological formations.

CASE
Connecticut Academy of Science and Engineering.

CCEF
The Connecticut Clean Energy Fund administers programs using funds collected from ratepayers to develop renewable generation, as well as research and develop emerging technologies.

CEAB
Connecticut Energy Advisory Board's primary goal remains to encourage competing energy solutions and to provide the opportunity to review multiple energy solutions simultaneously. The CEAB is responsible for representing the state in regional energy planning, participating in the state's annual load forecast proceeding, and reviewing the procurement plan submitted by electric distribution companies.

CEEF
Connecticut Energy Efficiency Fund (also known as the Conservation and Load Management Fund) is a ratepayer supported fund administered by the Electric Distribution Companies, with the advice and assistance of the Electric Conservation Management Board, to support increased installation of demand side management measures..

CHP
Combined Heat and Power, largely synonymous with "cogeneration," is the simultaneous production of electricity and heat using a single fuel. The heat produced from the electricity-generating process is captured and used to produce steam or hot water. CHP requires a host site where the steam or hot water can be used as a heat source for industrial or domestic purposes.

CL&P
Connecticut Light & Power is one of Connecticut's distribution utilities.

CO_2
Carbon Dioxide.

Cost of Service Contract
A utility is allowed to set rates based on the cost of providing service to customers and the right to earn a limited profit.

Demand
The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time.

DEP
Department of Environmental Protection.

DG
Distributed Generation, generates electricity from many small energy sources. It reduces the amount of energy lost in transmitting electricity because the electricity is generated very near where it is used, perhaps even in the same building. This also reduces the size and number of power lines that must be constructed.

Distribution Utilities
Connecticut Light & Power and United Illuminating; terminology used for this Procurement report.

DPUC
Department of Public Utility Control.

DSM
Demand-Side Management refers to programs designed to influence the amount or timing of demand-side (the use of energy, as opposed to the supply of energy) energy use, including peak demands and load shapes. In the NTA study, the term DSM includes both Energy Efficiency and Demand Response.

ECMB
Energy Conservation Management Board.

EEPP
Electric Efficiency Partnership Program.

Energy Efficiency
Energy efficiency refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt hours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (for example, lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

FCA
Forward Capacity Auction is an auction where capacity is auctioned off and ISO ends up purchasing just enough capacity to meet the Installed Capacity Requirement from the most economical sources. The resulting price is then the auction clearing price, which all selected suppliers are paid.

FCM
Forward Capacity Market is the process used by ISO New England to purchase sufficient capacity for reliable system operation for a future year at competitive prices where all resources, both new and existing and both supply and demand, can participate.

FMCC
Federally Mandated Congestion Charges are charges that recover costs associated with the Federal Energy Regulatory Commission’s (FERC) Standard Market Design (SMD).

Hedging Contracts
Hedging contracts establish future prices and quantities of electricity independent of the short-term market. Derivatives may be used for this purpose.

IRP
Integrated Resource Plan, a set of regulatory policies and utility planning practices to develop demand-side and supply-side resources that are in the best economic and environmental interest of the Utility, its customers, and society.

ISO-New England
Independent System Operator-New England is a regional transmission organization that meets the electricity demands of all six New England states. ISO New England ensures the reliability of bulk power generation and transmission, oversees the administration of New England's wholesale electricity market, and manages regional planning processes.

Load
The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

LFRM
Locational Forward Reserve Market, monthly reservation payments based on auction clearing price (Seasonal); can be a portfolio of resources; call on energy based on defined heat rate.

NEEWS
New England East-West Solution is a proposed transmission project.

NO_x
Nitrogen Oxide.

NTA
Non-Transmission Alternative includes both local supply (generation) and demand (energy efficiency and demand response) resources.

NU
Northeast Utilities.

OCC
The State of Connecticut's Office of the Consumer Counsel.

Peak Load
Peak load is the maximum load during a specified period of time.

Peaking Generator
A plant usually housing old, low-efficiency steam units; gas turbines; diesels; or pumped-storage hydroelectric equipment normally used during the peak-load periods.

Renewable Resource
Naturally, but flow-limited resources that can be replenished. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades, or perhaps centuries, they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar and wind. State statute sets forth which resources are categorized renewable. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

REC
Renewable Energy Certificate, tradable environmental commodities which represent proof that 1 megawatt-hour (MWh) of electricity was generated from an eligible renewable energy resource.

Reliability
Electric system reliability has two components—adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

RFP
Request for Proposal.

RGGI
Regional Greenhouse Gas Initiative is a cooperative effort by nine Northeast and Mid-Atlantic states to discuss the design of a regional cap-and-trade program initially covering carbon dioxide emissions from power plants in the region.

RMR
A Reliability Must Run generator is designated to provide Daily RMR service with which the ISO has entered into an RMR contract.

RPS
The Renewable Portfolio Standard is individual state requirements which mandate a certain percentage of a utility's power plant capacity or generation to come from renewable sources by a given date.

SCR
Selective Catalytic Reduction is emissions control technology in coal plants that uses ammonia injection in the flue gas to convert nitrogen oxide emissions to elemental nitrogen and water.

Scrubber
One of the primary devices that control gaseous emissions, especially acid gases.

SNCR
Selective Non-Catalytic Reduction is a method for reducing nitrogen oxide emissions in conventional power plants that burn biomass, waste, and coal.

SO_2
Sulfur Dioxide.

Stranded Costs
Prudent costs incurred by a utility which may not be recoverable under market-based retail competition. Examples are un-depreciated generating facilities, deferred costs, and long-term contract costs.

Total Resource Cost Test
Measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

Transmission
The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

UI
United Illuminating is one of Connecticut's distribution utilities.

APPENDICES

APPENDIX A

Legislation Section 51 and Section 52 of Public Act Number 07-242

2008 Comprehensive Plan for the Procurement of Energy Resources

Prepared by:
The Connecticut Energy Advisory Board

Approved August 1, 2008

For an electronic version of the entire act, click this link:
www.cga.ct.gov/2007/ACT/PA/2007PA-00242-R00HB-07432-PA.htm

HOUSE BILL NO. 7432

Public Act No. 07-242: An Act Concerning Electricity And Energy Efficiency

Section 51

Sec. 51. (NEW) (*Effective from passage*) (a) The electric distribution companies, in consultation with the Connecticut Energy Advisory Board, established pursuant to section 16a-3 of the general statutes, as amended by this act, shall review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.

(b) On or before January 1, 2008, and annually thereafter, the Distribution Utilities shall 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.

(c) 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 procurement plan shall specify (1) the total amount of energy and capacity resources needed to meet the requirements of all customers, (2) the extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs, (3) needs for generating capacity and transmission and distribution improvements, (4) how the development of such resources will reduce and stabilize the costs of electricity to consumers, and (5) the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources.

(d) The procurement plan shall consider: (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.

(e) The board, in consultation with the regional independent system operator, shall review and approve or review, modify and approve the proposed procurement plan as submitted not later than one hundred twenty days after receipt. For calendar years 2009 and thereafter, the board shall conduct such review not later than sixty days after receipt. For the purpose of reviewing the plan, the Commissioners of Transportation and Agriculture and the chairperson of the Public Utilities Control Authority, or their respective designees, shall not participate as members of the board. The electric distribution companies shall provide any additional information requested by the board that is relevant to the consideration of the procurement plan. In the course of conducting such review, the board shall conduct a public hearing, may retain the services of a third-party entity with experience in the area of energy procurement and may consult with the regional independent system operator. The board shall submit the reviewed procurement plan, together with a statement of any unresolved issues, to the Department of Public Utility Control. The department shall consider the procurement plan in an uncontested proceeding and shall conduct a hearing and provide an opportunity for interested parties to submit comments regarding the procurement plan. Not later than one hundred twenty days after submission of the procurement plan, the department shall approve, or modify and approve, the procurement plan. For calendar years 2009 and thereafter, the department shall approve, or modify and approve, said procurement plan not later than sixty days after submission.

(f) On or before September 30, 2009, and every two years thereafter, the Department of Public Utility Control shall report to the joint standing committees of the General Assembly having cognizance of matters relating to energy and the environment regarding goals established and progress toward implementation of the procurement plan established pursuant to this section, as well as any recommendations for the process.

(g) All electric distribution companies' costs associated with the development of the resource assessment and the development of the procurement plan shall be recoverable through the systems benefits charge.

Section 52

Sec. 52. (NEW) (*Effective from passage*) (a) The Department of Public Utility Control shall oversee the implementation of the procurement plan approved by the Department of Public Utility Control pursuant to section 51 of this act. The electric distribution companies shall implement the demand-side measures, including, but not limited to, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies, specified in said procurement plan through the comprehensive conservation and load management plan prepared pursuant to section 16-245m of the general statutes, as amended by this act for review by the Energy Conservation Management Board. The electric distribution companies shall submit proposals to appropriate regulatory agencies to address transmission and distribution upgrades as specified in said procurement plan.

(b) If the procurement plan specifies the construction of a generating facility, the department shall develop and issue a request for proposals, shall publish such request for proposals in one or more newspapers or periodicals, as selected by the department, and shall post such request for proposals on its web site. Pursuant to a nondisclosure agreement, the department shall make available to the Office of Consumer Counsel and the Attorney General all confidential bid information it receives pursuant to this subsection, provided the bids and any analysis of such bids shall not be subject to disclosure under the Freedom of Information Act. Three months after the department issues a final decision, it shall make available all financial bid information, provided such information regarding the bidders not selected be presented in a manner that conceals the identities of such bidders.

(1) On and after July 1, 2008, an electric distribution company may submit proposals in response to a request for proposals on the same basis as other respondents to the solicitation. A proposal submitted by an electric distribution company shall include its full projected costs such that any project costs recovered from or defrayed by ratepayers are included in the projected costs. An electric distribution company submitting any such bid shall demonstrate to the satisfaction of the department that its bid is not supported in any form of cross subsidization by affiliated entities. If the department approves such electric

distribution company's proposal, the costs and revenues of such proposal shall not be included in calculating such company's earning for purposes of, or in determining whether its rates are just and reasonable under, sections 16-19, 16-19a and 16-19e of the general statutes, as amended by this act. An electric distribution company shall not recover more than the full costs identified in any approved proposal. Affiliates of the electric distribution company may submit proposals pursuant to section 16-244h of the general statutes, regulations adopted pursuant to section 16-244h of the general statutes and other requirements the department may impose.

(2) If the department selects a non-electric distribution company proposal, an electric distribution company shall, within thirty days of the selection of a proposal by the department, negotiate in good faith the final terms of a contract with a generating facility and shall apply to the department for approval of such contract. Upon department approval, the electric distribution company shall enter into such contract.

(3) The department shall determine the appropriate manner of cost recovery for proposals selected pursuant to this section.

(4) The department may retain the services of a third-party entity with expertise in the area of energy procurement to oversee the development of the request for proposals and to assist the department in its approval of proposals pursuant to this section. The reasonable and proper expenses for retaining such third-party entity shall be recoverable through the generation services charge.

(c) The electric distribution companies shall issue requests for proposals to acquire any other resource needs not identified in subsections (a) or (b) of this section but specified in the procurement plan approved by the Department of Public Utility Control pursuant to section 51 of this act. Such requests for proposals shall be subject to approval by the department.

APPENDIX B

Findings and Recommendations of the Distribution Utilities

2008 Comprehensive Plan for the Procurement of Energy Resources

Prepared by:
The Connecticut Energy Advisory Board

Approved August 1, 2008

FINDINGS AND RECOMMENDATIONS OF THE DISTRIBUTION UTILITIES

Note: This entire appendix is excerpted from the IRP, Section III B and Section IV.

1. Summary of Findings

The analytical results presented above suggest the following ten high-level findings, assuming that planned capacity additions and DSM programs are realized as projected in each solution, each of which is discussed in more detail below:

1. Regional resource adequacy needs are satisfied for the next several years.
2. Connecticut's local resource adequacy needs are satisfied for the foreseeable future.
3. Market prices will continue to be high and volatile.
4. Natural gas dependence will persist.
5. External, uncontrollable factors are the primary drivers of customer costs.
6. Renewable Portfolio Standards are unlikely to be fully met with renewable generation.
7. Nuclear and DSM mitigate CO_2 emissions more effectively than other resource solutions.
8. Increased DSM could reduce customer Costs, CO_2 emissions, and gas usage.
9. Non-gas baseload generation would reduce dependence on natural gas.
10. "Market Regime" vs. "Cost-of-Service" affects rate stability, and may have future customer cost implications.

1. Regional Resource Adequacy Needs are Satisfied for the Next Several Years

After taking into account planned generation additions, recent and planned transmission projects, and demand-side measures that are planned or underway, and assuming no retirements, new electricity resources will not be needed to attain reliability targets for several years in Connecticut or elsewhere in New England. Under most plausible futures, New England as a whole will need additional resources beyond the next five years. As part of the overall New England market, Connecticut will share in this resource need, but additional resources need not be located within Connecticut in this time frame.

2. Connecticut's Local Resource Adequacy Needs are Satisfied for the Foreseeable Future

Planned generation capacity additions, transmission enhancements and demand-side measures mean that Connecticut will satisfy its Local Sourcing Requirement (LSR) for many years, perhaps decades, under the scenarios examined in this report. This is partially due to the projected addition of DSM and generating capacity, including 279 megawatts of quick start capacity needed to satisfy the Connecticut Local Forward Reserve Market (LFRM) requirements. However, this analysis assumes no significant retirement of generating capacity in Connecticut, although some of the older oil-fired units are projected to earn sub-normal returns and/or experience difficulties covering their fixed O&M costs over the longer term; potentially resulting in retirement or reapplication for "reliability-must-run" status. Also, no significant congestion price differentials are forecast between Connecticut and the rest of New England. Transmission enhancements already under construction and planned generation will resolve the significant bottlenecks and limited local supply resources that have affected Southwest Connecticut in the past.

3. Market Prices will Continue to Be High and Volatile

Despite an adequate supply of resources, Connecticut and New England electricity prices are likely to remain at levels that will concern consumers and regulators, and prices will remain volatile. This is due primarily to the fact that electricity prices in New England are closely linked to natural gas prices, as our study confirms. Gas prices are volatile and uncertain, and likely to remain fairly high.

4. Natural Gas Dependence Will Persist

Natural gas is the fuel for about 40% of New England's power, but its impact on market prices is disproportionately large. Because it will remain the dominant price-setting fuel for electricity, its influence on prices will continue regardless of future events or resource decisions. Dependence on natural gas for power generation poses two potential problems. First, consumers are exposed to high and uncertain power costs because gas prices are high and volatile. Second, using large amounts of natural gas for electricity generation increases both the likelihood and the potential impact of gas supply disruptions, particularly in the winter months when overall gas usage is highest. This study only notes differences of natural gas consumed, but does not analyze the increased probability or cost of potential fuel disruptions on generating capability.[82] But because much of the existing generation base is gas-fired, and gas is the price-setting fuel for electricity, to substantially change the region's dependence on gas would take a long time and exceptional effort and expense. This analysis did not investigate the sufficiency of gas supply, however; gas supply is a concern, and should be thoroughly investigated prior to developing a long term strategy for the addition of resources in Connecticut.

5. External, Uncontrollable Factors Are Primary Drivers of Customer Costs

External factors that cannot be controlled by utilities or regulators, such as gas prices, climate policy and economic growth, can have a much larger impact on market outcomes and resource costs than the factors that can be controlled. A large part of the reason for this is that factors such as gas prices or climate policy can affect all resources, existing and new, while resource strategies that involve physical investments in new resources only affect the portfolio at the margin. Although the impact of marginal physical resources on the overall market outcomes or resource costs are relatively small (because additions are small relative to the installed capacity base),procurement strategies might alter the contractual relationship between load-serving entities and generators, or direct investment in physical generating capacity by load-serving entities, could impact customer cost.

6. Renewable Portfolio Standards Are Unlikely to Be Fully Met with Renewable Generation

Appendix E describes recent experience under the Connecticut renewable portfolio standard (RPS) requirements as well as under similar policies in New England. The discussion in Appendix E concludes that the Connecticut RPS is unlikely to be met by renewable generation, but instead load serving entities (LSEs) are increasingly likely to rely on alternative payments to the state at a mandated price of $55 per megawatt-hour for any short fall. By the middle of

82 PA 07-242 supports dual fuel capability with respect to certain generating units and at the discretion of the DPUC.

next decade, the statewide annual customer cost of complying with the requirement would exceed $200 million. Connecticut has limited amounts of attractive renewable resource options; it has little economic potential for wind and solar power, and even less for other renewables like wave, tidal, geothermal, etc. Other parts of New England have more promising renewable resource potential (for example, wind in northern New England). However, even reliance on a regional rather than state-level approach may not resolve the problem for Connecticut, since it is possible that New England in aggregate will be unable to achieve its combined renewable targets. This issue warrants additional study, particularly regarding the potential to access remote renewable resources for Connecticut, which may require the development of additional transmission capacity.

7. Nuclear and DSM Mitigate CO_2 Emissions More Effectively than Other Resource Solutions

CO_2 emissions will increase under a Conventional Gas resource solution (though the additional DSM incorporated in all Resource Solutions helps to mitigate this somewhat.) Additional DSM will further limit CO_2 growth, but not cause a reduction. As expected, the addition of nuclear generation would cut a significant amount of CO_2 emissions, while additional coal capacity would increase it. Opportunities for coal with carbon sequestration are limited by a lack of the appropriate geology in Connecticut and New England.

8. Demand Side Management Could Reduce Customer Costs, CO_2 Emissions, and Gas Usage

If achievable as characterized in our analyses, DSM (both demand response and energy efficiency programs) are effective in mitigating future peak and energy growth. The analyses assume a substantial amount of “Reference Case” DSM in all Resource Solutions (for example, much more than assumed by the ISO in its load projections), and still more DSM in the DSM-Focus solution. This additional DSM, if it is similarly effective, would also be valuable. (This analysis has not attempted to optimize the type or quantity of DSM programs, but simply evaluated two different levels of specified DSM programs.)

The results show that DSM can reduce overall customer costs. Under some circumstances, DSM can increase average unit costs (cents per kilowatt hour). When consumption volumes are changing, a change in unit costs may not accurately reflect customer impacts. How costs are recovered from particular customers or classes can affect whether their rates and/or costs go up or down. This is a question of cost allocation, a ratemaking issue not addressed here.

9. Non-Gas Baseload Generation Would Reduce Dependence on Natural Gas

Baseload generation (coal or nuclear), if procured in a way that mimics cost of service to consumers, can help to limit exposure to natural gas price risks, though if gas prices go down rather than up, this could commit customers to higher fixed costs. Under a purely market-based regime (that is, if baseload generation was merchant-owned and procured for customers at market prices), customers would receive no protection from gas prices; their costs would be virtually the same as if conventional gas generation had been added.

10. Market Regime vs. Cost-of-Service Affects Rate Stability and May Have Future Customer Cost Implications

As constructed/assumed, the hypothetical "Cost-of-Service" regime has substantially lower costs than the "Market" regime, across all scenarios and strategies studied; however, these results indicate more analysis is warranted. The overall cost levels used in the analysis may not offer a realistic comparison on a regional market basis, because it is probably not possible to put all generating assets back under cost of service regulation at historic embedded costs. The actual purchase costs for existing generation would not likely be at the levels assumed in the Cost of Service results because the fixed costs for some of the existing assets assumed in the Cost of Service analysis are below current market values. However, output from new construction owned outright and output from new assets acquired via long-term contracts could potentially be obtained at prices reflecting Cost of Service, but this was not evaluated in this study. The results also show that the range of costs is much smaller under Cost of Service. The potential range of total supply costs is generally lower than the range of market prices. This is primarily because under a market regime, the market price for all power is determined by the last unit of supply. In very simple terms, if the cost of the last unit of supply increases by 10%, then under a market regime customer costs increase by 10%. But the total cost of generating power from all sources varies by much less than 10% (many of these costs are fixed and don't vary with the last unit's costs). If customers were to be supplied under a regime more closely reflecting actual generating costs, customer costs will increase by less than 10%. Even if only some assets are procured on a cost basis, this will reduce customers' exposure to uncertain and volatile prices. As discussed below, it may be possible to procure power from some existing and/or new resources in ways that mimic cost-based pricing and allow customers to enjoy some cost-stabilization.

It is crucial to note here that while it is possible to reduce the uncertainty and volatility of customers' costs, it may not be possible to substantially reduce the expected level of costs in the near- or mid-term. However, long-term contracts for the output of new or existing assets can reduce uncertainty which can lower costs. Such questions of procurement and risk management are beyond the scope of this resource planning effort, but are likely to be important issues to consider in addressing the concerns of Connecticut customers.

2. Recommendations

The key findings outlined above are based upon the analysis performed by The Brattle Group, and lead to four primary recommendations representing a possible path forward to improve electricity procurement in Connecticut. Steps taken in response to these recommendations could help provide Connecticut customers with reliable, environmentally responsible electric service at more stable prices and potentially lower customer costs. Our primary recommendations regarding resource planning and procurement are:

1. Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.
2. 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.
3. 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.
4. Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas (though it will not be possible to eliminate gas dependence).

Recommendation 1: Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.

The potential for increased DSM to reduce customer costs, gas usage, and environmental emissions demonstrated in this analysis suggests that DSM should be pursued more aggressively. State regulatory authorities should examine, and where possible, explore methods to implement additional, cost-effective DSM. This would facilitate utility DSM programs to exceed current levels and expand upon the success of existing DSM programs. While the need for capacity is several years off in Connecticut, DSM programs are more cost-effective if they are pursued consistently over time, so it is reasonable to begin the ramp-up to more aggressive DSM programs in the near term.

The DSM resource investments assumed in this report far exceed the (already aggressive) levels pursued by the Distribution Utilities to date. The pace and magnitude of this expansion warrants careful monitoring of resource availability, costs, and operational effectiveness as the programs develop over time.

Recommendation 2: 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.

At the present time, the Distribution Utilities are constrained to enter into contracts with third-party suppliers with durations not to exceed three years to satisfy standard offer service obligations, which ensures that customers are exposed to power supply prices driven by short-term market prices. Our finding that customer costs would be more stable under a hypothetical cost-of-service regime suggests that supply arrangements incorporating cost-of-service principles could help to stabilize customer rates and potentially, under certain conditions, lower prices for the customer. This could be achieved by providing the Distribution Utilities 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, including baseload generation that is not dependent on natural gas. By reducing the extent to which utilities are forced to procure power through short-term contracts driven by regional spot market prices, such alternative procurement options can reduce customers’ exposure to uncertain and potentially high gas prices, and may provide to customers some benefits of a diverse fuel mix. Addressing these issues may involve the use of procurement strategies and risk management tools (such as fuel hedging strategies to complement electricity procurement) that go beyond what can be done in a resource planning context. In addition, strategies such as these should be coupled explicitly with the assurance of recovery of supply costs associated with approved long-term power procurement contracts.

Recommendation 3: 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.

Connecticut’s renewable portfolio standard as currently structured, while supporting Connecticut’s renewable goals, may impose additional costs on Connecticut customers without necessarily promoting new renewable generation to displace conventional generation. This observation suggests that additional study of RPS structure and costs is warranted at both the state and regional level to determine the best ways to meet future RPS requirements. At the state level, for example, the criteria for disbursing funds derived from alternative compliance payments might be re-examined under the current circumstances. Further analysis could also examine the potential to fashion regionally-coordinated policies to address possible renewable shortfalls and/or regional projects in transmission and renewable capacity.

Recommendation 4: Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas.

Non-gas baseload generation (for example, coal, and nuclear) offers a greater reduction in gas use (particularly in wintertime, when deliverability concerns are highest) than other resource options studied in this report. Although not assessed in this report significant renewable generation could also mitigate gas dependence.

To the extent that market participants' investment in non-gas-fired baseload generation is deemed insufficient to address these risks, state regulatory authorities should consider allowing contractual or ownership arrangements or other policy options to enable or encourage investment in such baseload capacity. Such options should be considered in concert with efforts to reduce dependence on natural gas use in all sectors (for example, heating). Both the cost and CO_2 emissions implications of all non-gas options should be considered.

APPENDIX C

CEAB Preliminary Assessment of the Integrated Resource Plan

2008 Comprehensive Plan for the Procurement of Energy Resources

Prepared by:
The Connecticut Energy Advisory Board

CEAB
Connecticut Energy Advisory Board

Approved August 1, 2008

La Capra Associates

INITIAL REVIEW OF
INTEGRATED RESOURCE PLAN FOR CONNECTICUT

A JANUARY 1, 2008 REPORT
PREPARED BY

CONNECTICUT LIGHT AND POWER UNITED ILLUMINATING

FOR COMPLIANCE WITH
REQUIREMENTS IN

SECTION 51 OF PUBLIC ACT NO. 07-242

PREPARED BY

La Capra Associates, Inc.

Twenty Winthrop Square
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January 28, 2008

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Appendices

A. Full Text of Section 51 of Public Act No. 07-242 *An Act Concerning Electricity and Energy Efficiency*

B. Summary Scorecard for Sections 51-B, 51-C, and 51-D

EXECUTIVE SUMMARY

On January 1, 2008, Connecticut Light & Power and United Illuminating submitted a report entitled *An Integrated Resource Plan for Connecticut* to the Connecticut Energy Advisory Board for its review. The Distribution Utilities prepared this report in accordance with Section 51 of Public Act No. 07-242, An Act Concerning Electricity and Energy Efficiency. Section 51 requires the CEAB, in consultation with the Independent System Operator – New England, to review the Distribution Utilities' IRP and approve it as submitted or as modified. The CEAB must then submit the approved plan to the Department of Public Utility Control for its consideration no later than April 30, 2008.

La Capra Associates offers this initial review of the Distribution Utilities' IRP to the CEAB as a starting point for its consideration of the Distribution Utilities' IRP.[83] At the CEAB's request, La Capra Associates has conducted a preliminary review of the Distribution Utilities' IRP. The objective of this preliminary review has been to assess the extent to which the Distribution Utilities' IRP provides the information requirements set forth in Section 51.[84]

La Capra Associates has conducted this expedited initial review during January. This review has been facilitated by the Distribution Utilities' January 4, 2008 presentation to the CEAB and, in addition, the Distribution Utilities made their IRP team available to meet with La Capra Associates for a day-long technical discussion of the Distribution Utilities' IRP on January 10, 2008.

Key Observations from the Review

In our view, the Section 51 requirements set a very constructive and comprehensive set of requirements for an integrated resource planning and procurement planning process for Connecticut. It is also our view that Section 51 sets very aggressive timelines for the preparation and review.

At the outset, we observe that the Distribution Utilities' have made a concerted effort to prepare a planning report that is responsive to the requirements of Section 51. They have prepared a substantial set of assessments in the six months since Public Act No. 07-242 became law. However, the Distribution Utilities stress the limitations of their work to date and indicate that the January 1, 2008 report:

[83] La Capra Associates leads a consulting team which has been retained by the CEA B to assist with the CEAB's review and approval of the Distribution Utilities' IRP.

[84] In parallel with this review for compliance with Section 51, La Capra Associates is proceeding with a technical review of the assessments conducted by the Distribution Utilities.

- Is a resource planning study, not a procurement plan
- Has limited analysis related to transmission
- Is not a siting analysis for new generation
- Is not a procurement risk management study
- Is not a renewable energy market study

We offer the following key observations on the contents of the Distribution Utilities' IRP relative to the requirements of Section 51:

1. Planning Assessments: The Distribution Utilities' IRP fully or partially meet the requirements in five of the six statutory areas.
2. Procurement Plan Requirements: The Distribution Utilities' IRP fully or partially meet the requirements in four of the five statutory areas.
3. Procurement Plan Considerations: The Distribution Utilities' IRP fully or partially meet the requirements in six of the seven statutory areas.

A Summary Scorecard reflecting our judgment as to the Distribution Utilities' IRP Degree of Compliance in each statutory area is attached as Appendix B. The Degree of Compliance noted on Attachment B indicates our view on the level of completeness, and does not indicate whether we have made any determination as to agreement on assumptions or results. Our review of the assumptions and results is ongoing and will be addressed in later stages of the review.

Our primary observations and concerns are:

1. The IRP includes a responsive assessment of the energy and capacity requirements. The Distribution Utilities conclude that Connecticut does not need added local generation for some time. However, this assessment is premised on an assumption of no retirements.
2. The IRP contains meaningful assessment of the DSM potential needed to eliminate growth in energy in demand. More work is needed on how best to accomplish that goal.
3. The IRP includes a meaningful assessment of economic risks using scenario analysis and modeling of the regional markets. This assessment does not currently assess the risks of potential retirements of older generation and does not integrate transmission planning.
4. The IRP analysis provides an assessment of greenhouse gas emissions and potential costs. The assessment does not consider many other environmental requirements, such as the Clean Air Interstate Rule or the High Electric Demand Days initiative.

5. The Distribution Utilities have focused their planning on state-wide generation and demand-side resources. The assessments do not consider transmission planning issues.
6. The Distribution Utilities four recommendations are in the form of recommendations for additional investigation. The IRP does not contain a Procurement Plan or an Action Plan for implementation.

Potential Issues for CEAB's Review and Approval Process

Section 51 provides a 120 day period, through April 30, 2008 for the CEAB to review and approve or review, modify and approve the procurement plan. Based upon our initial review of the Distribution Utilities' IRP, we offer the following ideas on topics that the CEAB may wish to address in this review process:

- Working with the Distribution Utilities to:

  1. Better define the actions needed to expand the DSM programs.
  2. Better assess the implications of more stringent emissions regulations on older Connecticut generating units and the associated need for new resources.
  3. Develop an approach to integrate the Distribution Utilities' IRP with transmission planning needs assessments.
  4. Better assess the in-state renewable energy potential and development challenges.
  5. Better define the costs and benefits of long term contracting and options for implementing that recommendation.

- Working in consultation with ISO New England:

  1. Review the Forward Capacity Market Auction results for Connecticut resource planning implications.
  2. Review recent market congestion information to assess the Distribution Utilities' finding that congestion is largely mitigated.

Report Structure

This Initial Review Report is structured to parallel the provisions of Section 51. First, Section I of this report describes the scope of review. Next, Sections II through V this report discuss the four subsections and the twenty requirements contained Section 51 subsections (a) through (d) including: Planning Assessments; Procurement Plan Requirements; Procurement Plan Considerations; and, overall objectives for the Comprehensive Procurement Plan. Finally, Section VI offers some suggestions for the CEAB to consider for the 2008 review/approval process or in later cycles of this planning process.

I. SCOPE OF REVIEW

A. Background

Section 51 of Public Act 07-242 (Section 51), An Act Concerning Electricity and Energy Efficiency ("Section 51"), requires Connecticut Light and Power ("CL&P") and United Illuminating ("UI") (together, "the Distribution Utilities") to review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources. Section 51 requires CL&P and UI prepare this assessment and plan annually, with the first of such assessment and plan to be submitted to the Connecticut Energy Advisory Board ("CEAB") for its review by January 1, 2008. Public Act 07-242, and the requirements in Section 51, became effective on July 1, 2007.

Following passage of PA 07-242, CL&P and UI retained The Brattle Group as consultants and together they prepared *An Integrated Resource Plan for Connecticut.* This January 1, 2008 report (the "Companies' IRP") was submitted to the CEAB for its review.

Section 51 requires that the CEAB conduct a review of this January 1, 2008 plan. For the 2008 plan, this review process is a 120 day process. The statute contemplates the review to include consultation with ISO New England and a public hearing. At the conclusion of this review, the CEAB is to submit the reviewed procurement plan, with modifications as appropriate, together with a statement of any unresolved issues, to the Department of Utility Control ("DPUC") for its subsequent review as provided in Section 51.

La Capra Associates was retained to assist the CEAB with its review of the January 1, 2008 procurement plan.[85] As the first part of that assistance, La Capra Associates has been asked to conduct a preliminary review of the Distribution Utilities' IRP within the first 30 days of the review process and to present that preliminary assessment to the CEAB for its consideration by February 1, 2008. The objective of this preliminary review is to assess the extent to which the Distribution Utilities' IRP provides the information requirements set forth in Section 51.

This report contains La Capra Associates' preliminary assessment of the contents of the Distribution Utilities' IRP relative to the requirements set forth in Section 51. This report is designed to inform the CEAB on the contents of the Distribution Utilities' IRP to

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[85] La Capra Associates leads a consulting team which also includes subcontractors GDS Associates and Heather Hunt..

facilitate the CEAB's consideration of the issues and subsequent work toward a final report that will be delivered to the DPUC on April 30, 2008. The CEAB and other readers of this report should also recognize that the time available to the Distribution Utilities to prepare this first annual plan was limited relative the scope of the effort set forth in Section 51, as these requirements became effective on July 1, 2007.

B. Preliminary Review Process

This preliminary review has been conducted by personnel at La Capra Associates. Due to the limited time provided for this preliminary assessment, there was limited opportunity for input to this review from CEAB members or their staff representatives. This review, therefore, represents the initial observations of La Capra Associates and does not necessarily represent the views of the CEAB or any of its members.

This review has been conducted as a technical review. La Capra Associates' expertise in electric utility planning was utilized to assess the contents of the Distribution Utilities' IRP and requirements of Section 51 from the perspective of professionals with expertise in planning. This assessment did not include any legal review and it is not intended to offer any legal opinions.

The Distribution Utilities and their consultants from The Brattle Group provided a presentation of the Distribution Utilities' IRP to the CEAB on January 4, 2008. In addition, the Distribution Utilities and The Brattle Group made their IRP team available to meet with La Capra Associates for a technical discussion of the Distribution Utilities' IRP on January 10, 2008. These sessions have facilitated the initial review conducted by La Capra Associates' to gain necessary understanding of the assumptions, methods, and results contained in the Distribution Utilities' IRP. However, it is important to note that, to date, these discussions with the Distribution Utilities, while very helpful, have been limited and informal. As such, the observations made in this report will be further developed through continued review of supporting documents and information exchange.

C. Structure of this Preliminary Assessment Report

Section 51 of Public Act No. 07-242 has seven subsections. They set forth requirements relative to the Distribution Utilities' preparation and filing of the plan. They also detail the CEAB's and DPUC's review and reporting requirements, and cost recovery provisions. The first four of these subsections, (a) through (d), contain requirements relevant to the Utilities' preparation of the annual assessments and procurement plans in consultation with the CEAB. The complete text of Section 51 is included in Appendix A of this report. The assessments contained in this report address only subsections (a) through (d).

In Section II of this report, we provide a review of the contents of the Distribution Utilities' IRP with the Planning Assessments required to be included in the January 1, 2008 in accordance with subsection 51(b). This subsection sets forth six areas where planning assessments are required.

In Section III of this report, we provide a review of the Distribution Utilities' IRP with respect to the Procurement Plan Requirements set forth in subsection 51(c). This subsection contains five requirements.

In Section IV of this report, we provide a review of the Distribution Utilities' IRP with respect to the Procurement Plan Considerations set forth in subsection 51(d). This subsection contains seven areas that are to be considered in the Procurement Plan.

In Section V of this report, we provide a review of the Distribution Utilities' IRP with respect to the requirements for a Comprehensive Procurement Plan for energy resources in accordance with subsection 51(a).

Section VI includes suggestions for areas of focus in remainder of the CEAB's review and approval process and in preparing the April 30, 2008 procurement plan report to the DPUC.

II. SECTION 51(B): PLANNING ASSESSMENTS

Subsection 51(b) sets forth requirements for six areas of planning assessments that the Distribution Utilities were to include in the January 1, 2008 report. The planning assessments required in this section are consistent with the planning studies that are conducted as the basis for utility system planning. Special emphasis is placed on assessments that will inform the Connecticut priorities of managing load growth, mitigating environmental impacts of power system environmental impacts, and managing the level and volatility of costs.

For each of the six assessment requirements, we offer a description of the requirement, a description of the treatment of that requirement in the Distribution Utilities' IRP, and an indication of our impression of the degree of compliance with the requirement. For the degree of compliance, we apply our judgment to indicate one of the following:

FULL	Indicates that the IRP meets or largely meets the requirement
PARTIAL	Indicates that the IRP addresses the requirement in part, but not fully.
LIMITED	Indicates that the IRP has some treatment of the requirement, but that it is largely insufficient to meet the requirement
N/A	Indicates that the requirement is Not Addressed in any manner in the Company's IRP.

A Summary Scorecard for each of these component requirements is included in Appendix B of this report.

The review of the Distribution Utilities' IRP contained in this report is a review for completeness, not a technical review. For example, an indication that the Utilities' IRP fully complies with the requirement only indicates that an assessment has provided and that the represented approach for that assessment is consistent with our expectations for such an assessment. Degree of Compliance does not indicate whether La Capra Associates has made any determination as to agreement on assumptions or results. Review of the assumptions and results is ongoing at the time of this writing and will be addressed in later stages of the review. In this section, we assess the materials provided by the utilities for each of the six requirements and determine whether the form of that assessment is consistent with (or better than) the type of assessment that is typically provided in utility plans.

A. The Energy And Capacity Requirements Of Customers For The Next Three, Five And Ten Years

Description of the Requirement:

This assessment is a standard utility planning analysis including load forecasting and installed capacity requirements assessments.

Energy and capacity requirements, in total, are determined with load forecasting techniques that estimate the growth in electricity demand over time. This typically includes forecast of energy requirements by month/season/year and of peak demand (i.e., the highest hourly load in each month/season/year). ISO New England now does this form of assessment to set the installed capacity requirements for the Forward Capacity Market three years in advance. The Connecticut Siting Council (CSC) also collects and publishes such forecasts annually.

The assessment of the requirements for new or additional capacity and energy to meet requirements that cannot be met without new supplies is also typically conducted in this assessment. In this instance, a forecast of energy and capacity that will be available from existing sources is compared to the load forecast to determine any gaps between supply and demand over time.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities have included an assessment of the energy and capacity requirements for the 3, 5, and 10 year periods and for the year 2030 in Section II C of the Distribution Utilities' IRP. This assessment uses ISO-New England load forecasts to assess the needs requirements in the State, providing projections of total requirements and the need for new supplies for four scenarios. The requirements that the Distribution Utilities addressed include the Forward Capacity Market Installed Capacity Requirements and the Connecticut Local Sourcing Requirements, as well as consideration of new supplies under development now to meet the Forward Capacity Requirements or the Locational Forward Reserve market requirements.

From the assessment conducted, the Distribution Utilities conclude that no new generation additions are required in Connecticut over the next decade to meet the Local Sourcing Requirements of the ISO New England Forward Capacity Market, assuming no retirements of existing generation. (Companies' IRP, page 40)

Degree of Compliance: FULL

The Distribution Utilities have provided an assessment of energy and capacity requirements for each of the time horizons specified in the requirement.

B. The Manner Of How Best To Eliminate Growth In Electric Demand

Description of the Requirement:

We understand this requirement to be seeking a specific assessment of alternatives that would eliminate growth in overall electrical energy requirements, to determine the best approach among those alternatives, and an assessment of how to accomplish that best approach.

The use of the term “Electric Demand” we have assumed to refer to energy savings, based on the use of the terms “electric demand” and “peak electric demand” in requirement 3) in the subsection and in Section 94 (c) of PA 07-242.

This assessment requires an assessment of the potential for energy savings from energy efficiency programs that may be administered by the utilities and could also include consideration of other options, such as pricing options, building codes, or appliance efficiency standards. Studies are often conducted to assess the technical and economic potential for energy efficiency measures that utilities may offer in a demand side management program where the objective is to determine the limits of cost-effectiveness and budgets available for DSM programs. A study with an objective of elimination of load growth is less common and more aggressive.

Lastly, the use of “manner” in this requirement appears to be seeking an assessment of the ways to implement this level of Electric Demand reduction.

Summary of the Treatment of the Requirement in the Distribution Utilities’ IRP:

The Distribution Utilities have adapted the 2004 DSM potential study conducted by the Energy Conservation Management Board and other studies that the Distribution Utilities’ have conducted to prepare an aggressive “DSM-Focus” scenario. This scenario does eliminate growth in Electric Demand and Electric Peak Demand. However, the Distribution Utilities acknowledge “this analysis has not attempted to optimize the type or quantity of DSM programs, but simply evaluated two different levels of specified DSM." (Companies' IRP at Pages 42-43).

The Distribution Utilities document the two DSM Scenarios assessed in Appendix D. In this appendix, they describe the sources of the assumptions on the DSM-focus scenario and provide a discussion of issues that would need to be considered in developing a program to increase the level of DSM activity contemplated in this scenario. However, they do make clear that this scenario assessment is not a Conservation and Load Management (C&LM) or a DSM potential study (Companies' IRP Appendix D at page D-22).

The Distribution Utilities also mention that the Energy Conservation Management Board is planning an update to its 2004 DSM potential study for 2008, which may produce important information for addressing this objective further in the 2008 planning cycle.

Degree of Compliance: PARTIAL

The Distribution Utilities' assessment shows scenarios that accomplish the elimination of load growth. The Distribution Utilities have extended the existing available information on the maximum potential for DSM to illustrate the characteristics of the program that would be needed to accomplish the elimination of load growth. The Distribution Utilities' IRP presentation of this aggressive DSM scenario is helpful new information needed to consider such an aggressive DSM initiative.

The cost effectiveness of and demand reduction actions, whether they be programs offered by the utilities or building code changes does not appear within this report. The report (pages D-1 to D-2) refers to the cost-effectiveness for the DSM Focus plan only as "the estimate assumes that all measures that pass the Total Resource Cost (TRC) test are implemented…"

As is clearly stated in the Distribution Utilities' IRP, this assessment is not an implementation plan and it has not necessarily developed an optimal (or the "best") approach to accomplish this objective. This assessment does point to additional studies that should be conducted to allow future planning cycles to more fully address this requirement (Companies' IRP, Appendix D, pages D-20 to D-21).

C. How Best To Level Electric Demand In The State By Reducing Peak Demand And Shifting Demand To Off-Peak Periods

Description of the Requirement:

This requirement is the Peak Demand counterpart to the Electric Demand issues addressed in the previous requirement.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities IRP addresses both Peak Demand (capacity) and Electric Demand (energy) aspects of demand-side management in the IRP and the Appendix D.

The Distribution Utilities' estimates for demand response programs did not have the benefit of using prior potential studies, as the ECMB study in 2004 focused only on energy efficiency measures. This is another area identified for additional study.

Degree of Compliance: PARTIAL

The compliance on this is similar to the prior requirement on Electric Demand for very similar reasons. The Distribution Utilities' IRP offers an aggressive scenario and information to consider in expanding this resource, however, the information base is not yet sufficient to have a full assessment of the best approach to eliminating growth in Peak Demand.

D. 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

Description of the Requirement:

This requirement calls for assessments of current and future environmental regulations as they affect the operation of generation in Connecticut and the region. There are several areas of interest in Connecticut in this regard, including:

1) Greenhouse gas regulations are relevant to this planning process due to the 2009 implementation of the Regional Greenhouse Gas

Initiative in the Northern states and the expectations that some form of federal regulation of greenhouse gases will be implemented.

2) The Clear Air Interstate Rule will be placing further restrictions on NO_x and SO_2 emissions in Connecticut.
3) The High Electric Demand Days (HEDDs) program is focusing on reducing NO_x emissions during high peak demand days in ozone non-attainment zones.
4) Clean Air Mercury rules focus on reductions in mercury emissions reductions from coal facilities in Connecticut.
5) Renewable Portfolio Standards establish requirements for renewable energy production in Connecticut and throughout the region.

Rules in each of these areas, both existing and projected, have significant implications for the electric system planning process.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities' IRP includes a scenario analysis approach. The modeling used in this analysis included the assessment of CO_2, NO_x and SO_2 emissions and the tracking of carbon emissions relative to RGGI caps. The model also included the cost of emissions allowances in the operations generation in the region.

In this planning process, the Distribution Utilities' IRP assumes no retirements of existing generation and no changes in the emissions performance of existing generation units (i.e., no added emission control technologies).

With respect to renewable portfolio standards, the modeling included an assumption that Connecticut and the region would not have sufficient new renewable capacity to meet the RPS requirements. Based on that assumption, Renewable Energy Credits were assumed to be priced at the Alternative Compliance Payment.

Degree of Compliance: LOW

The primary emphasis in the Distribution Utilities' IRP was the tracking of carbon, NO_x and SO_2 emissions.

The emissions issues with existing units have been an area of significant interest to the CEAB and the DEP. The Distribution Utilities' IRP assessment does not include any assessment of alternatives to continued operation of those existing units that pose the challenges to compliance with CAIR, HEDDs, among others.

The Distribution Utilities' raise their concerns with respect to the ability of the market to meet the renewable portfolio standards. There is limited information in the plan on the potential for renewables development.

E. Energy Security And Economic Risks Associated With Potential Energy Resources

Description of the Requirement:

This requirement pertains to a potentially broad array of issues that affect the reliability of the power system or the stability of the pricing of electricity. Economic risks include limited diversity in fuels supplies (such as New England's heavy dependence on natural gas), volatile pricing in fuels or in market prices, and exposure to shortage pricing in the event of limited development of new, cost effective supplies. Security has several potential dimensions, including vulnerability to natural disasters, terrorism, fuel supply disruptions, or over reliance on foreign sources of fuel.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities' IRP addressed security and risk in three ways.

The first issue is fuel diversity and the exposure to natural gas price volatility and to natural gas supply disruptions in winter conditions. The primary metric for this is the amount of natural gas in the annual and seasonal fuel mix.

The second issue pertains to the exposure to market prices determined predominantly by natural gas prices. To assess this, the Distribution Utilities offer a comparative analysis of market pricing to cost of service pricing.

Lastly, the Distribution Utilities' IRP analysis also featured a scenario analysis approach. This offers the ability to examine a range of comparative metrics of cost and risk under four different views of future market conditions.

These risk issues are featured in two of the Distribution Utilities' four recommendations. The Distribution Utilities' recommend (Recommendation 2) the there be an exploration of longer term power contracts with merchant generation and utility owned generation to mitigate the economic exposure to short term market prices. The Distribution Utilities' also recommend (recommendation 4) that consideration be given to non-gas generation sources (such as coal, nuclear and renewables) to mitigate the gas price and availability risks.

Degree of Compliance: PARTIAL

The Distribution Utilities have presented significant analyses which illustrate the risk exposures featured in their recommendations. The Distribution Utilities' analysis leads them to recommend further consideration of risk mitigation issues. The Distribution Utilities' have offered this IRP as a planning study and not a procurement plan. Additional work is needed to develop these issues for a procurement plan recommendation.

The report does not contain any observation, conclusions or recommendations on the impact the implementation of and evolution of environmental regulations will have on Connecticut generation.

F. The Estimated Lifetime Cost And Availability Of Potential Energy Resources

Description of the Requirement:

This requirement pertains to two specific aspects of energy resources important to achieving or maintaining reliable and affordable electricity for Connecticut consumers: cost and availability. Potential energy resources refers broadly to the new (or refurbished) supply and demand-side resources to be considered in the plan, including generation facilities producing energy in Connecticut, energy efficiency programs in Connecticut, and transmission projects designed to enhance reliability and/or increase energy exchange capability between Connecticut and its neighboring systems. This requirement provides that the utilities should prepare an assessment of the availability of these resources and the estimated costs to design, construct or implement, and to operate and maintain these resources over their useful lives.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities address these issues in several ways.

For existing generation sources, the Distribution Utilities assumed that all units would remain available. Their analysis did not include retirement of any generation due to economic obsolescence, poor availability or regulations (such as environmental). More specifically, the utility modeling of The Plans and Scenarios do test internally within the model whether continued operation of all Connecticut generation makes sense economically. The analysis does not assume any investments are made in order to keep these facilities within environmental compliance limits for any emission.

For new generation resources, nuclear, coal, and gas-fired generation were assumed to be available and used in scenario analysis.

Natural gas is assumed to be available. Oil availability is not addressed or presumed in any analysis other than no retirements mentioned of any oil-fired generation in New England.

Renewable resources were assumed to be constrained, such that the Alternative Compliance Payment would determine the costs of the RPS requirement. Appendix E. does provide a levelized lifetime costs of renewable energy based generation

The Distribution Utilities prepared an assessment of the potential resource availability, building upon a 2004 demand-side resources potential study for ECMB. This is addressed further in Section III B, below.

In terms of costs of energy resources over the lifetime, the analysis incorporates estimates for natural gas and oil based on NYMEX and EIA growth rates. It is not apparent what prices were used for coal, nuclear, biomass or refuse, anywhere in the report.

The lifecycle cost of generation technologies only occurs with those technologies studied within the scenarios, combustion turbines, combined cycle, nuclear and super-critical coal were included. No assessment of the costs and availability of Combined Heat and Power (CHP) based generation.

Degree of Compliance: PARTIAL

The company assembled a reasonable set of planning assumptions for demand-side management resource and major generation facilities. The assessment was limited in the potential estimates for renewable energy resources, combined heat and power, and on the longevity of older, existing generation sources.

III. SECTION 51(C): PROCUREMENT PLAN REQUIREMENTS

Section 51 (C) establishes a first priority for the use of energy efficiency and demand-reduction resources to meet the needs identified for the Procurement Plan to the extent that these resources are cost-effective, reliable and feasible. This section also sets a requirement that demand side resources be considered on an equitable basis with non demand-side resources. In that context, this section specifically identifies five requirements for the contents of the Procurement Plan. For each of the five categories, we offer a description of the requirement, a description of the treatment of that requirement in the Distribution Utilities' IRP, and an indication of our impression of the degree of compliance with the requirement (using the same method as in the prior section). A Summary Scorecard for each of these requirements is included in Appendix B of this report.

A. Specify The Total Amount Of Energy And Capacity Resources Needed To Meet The Requirements Of All Customers

<u>Description of the Requirement:</u>

This requirement is met with the first of the six assessment requirements in Section 51-B, which is discussed in Section II A above.

<u>Summary of the Treatment of the Requirement in the Distribution Utilities' IRP</u>:

See description in Section II A above.

<u>Degree of Compliance:</u> FULL

See assessment in Section II A above.

B. Specify The Extent To Which Demand-Side Measures, Including Efficiency, Conservation, Demand Response And Load Management Can Cost-Effectively Meet These Needs

<u>Description of the Requirement:</u>

This requirement refers to a maximum achievable, cost-effective potential study for the range of demand-side measures encompassed in the requirement. This is a common assessment used to inform the development of a comprehensive demand-side procurement plan.

<u>Summary of the Treatment of the Requirement in the Distribution Utilities' IRP</u>:

The Distribution Utilities conducted an assessment of the potential for demand-side resources and included that assessment in the IRP. This assessment was based on an energy efficiency potential study conducted in 2004 for the Energy Conservation Management Board (ECMB). The Distribution Utilities supplemented and updated this study with more current information and added an estimate of the potential for demand response.

Degree of Compliance: FULL

The Distribution Utilities' review and adaptation of the existing studies in this area identified the need to conduct a comprehensive update to this study. The Distribution Utilities note that ECMB is planning such a study in 2008.

Time did not allow the Distribution Utilities to conduct a new and comprehensive study for January 1, 2008. In lieu of that, the 2004 work was adapted to provide the best readily available estimate. In context, this assessment complies with the requirement.

C. Specify The Needs For Generating Capacity And Transmission And Distribution Improvements

Description of the Requirement:

This requirement refers to assessments of 1) the adequacy of generation to meet the peak demand and energy requirements of customers, 2) the adequacy of the transmission system to meet reliability criteria and provide customers with efficient access to generation supplies, and 3) the adequacy of the distribution system to reliably serve customers.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities' IRP addresses only the generation component of this requirement, which is discussed in Section II A, above. In this assessment, they conclude that additional generation capacity is not needed in Connecticut in the next decade.

In discussing the limitations of the study, the Distribution Utilities note that they "...did not provide a cost/benefit analysis of transmission options; and did not compare the economics of transmission vs. generation or vs. demand-side options..." (Companies' IRP, page 48) They also indicate that the generation need analysis conducted did not consider location, only the aggregate amount of capacity needed to meet customer requirements.

In the scenario analysis, the Distribution Utilities did conduct sensitivity analysis of the market price results with and without the Connecticut portions of the NEEWS proposal.

Degree of Compliance: PARTIAL

The lack of any consideration of the transmission needs in this assessment is a significant limitation of this study. In light of the NEEWS plans and additional transmission needs assessment studies that are underway[86], the potential for interactions between demand-side and generation resources is significant. The requirement for assessment of demand-side resources on an equal footing with non demand-side resources should include transmission and distribution considerations.

D. Specify How The Development Of Such Resources Will Reduce And Stabilize The Costs Of Electricity To Consumers

Description of the Requirement:

This requirement refers to assessments and analyses that will test the proposed plans cost impact on customers, including overall costs and rates and the degree of stability in those costs over time. This requires the calculation of rate impacts and trends or average per unit costs under the future conditions when the various generation, DSM and transmission options are deployed.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities' report and analysis provides information on the per-unit costs of generation service for four different plans across the four scenarios. Average costs per kWh for the full generation service that is needed to meet customer demand were produced for each condition.

To test the cost implications for cost-of-service approaches to procurement, each scenario was evaluated under the Market Regime and the Cost of Service Regime futures.

The Distribution Utilities observe that their IRP analysis shows that the external factors, such as environmental compliance and the price of fuels, have a greater affect on stability than do the resources chosen.

86 At ISO New England's November 2007 Planning Advisory Committee meeting, the scopes for two studies assessing transmission needs in Connecticut were presented. ISO New England, Northeast Utilities and United Illuminating formed a study working group to perform an assessment of the needs for additional transmission in Southwest Connecticut by 2018. ISO New England and Northeast Utilities formed a study working group to perform an assessment of the needs for additional transmission in eastern Connecticut by 2018.

The Distribution Utilities' IRP cost analysis focuses on the generation cost components of customers cost of electricity. No cost estimates were included for Transmission, Distribution, Customer Service and System Benefits charges.

Degree of Compliance: PARTIAL

The Distribution Utilities use a scenario approach to prepare a comparative assessment of different resource strategies for four different scenarios. These results highlight the range of cost exposure customers have in scenarios with the most reliance on natural gas.

The Distribution Utilities' IRP does not determine an impact on rates in total or on average across customer classes. The average per unit costs calculated do not capture the effects of changes in T&D or customer service or the impact of changes in sales resulting from the DSM-Focus and the upward pressure on rates that occurs. While the Distribution Utilities' IRP does show how average generation costs vary by resource plan and by scenario, the attempt has not been made to show how to stabilize rates.

The Distribution Utilities' IRP points to their results, that under the hypothetical Cost of Service regime, average and total costs are lower than under the market regime. This observation is made without any comment or plan on how the assets can be acquired at Cost of Service.

The Company's recommendations call for further investigation into procurement strategies that would mitigate exposures to volatility in natural gas pricing and in market prices.

E. Specify The Manner In Which Each Of The Proposed Resources Should Be Procured, Including The Optimal Contract Periods For Various Resources

Description of the Requirement:

This aspect of requirements seeks specific plans for the procurement of the resources identified as needed in the resource needs assessments. This requirement seeks the action plan or implementation plan that is recommended to obtain the needed energy resources. Procurement of supplies is the principle mechanism for the Distribution Utilities given Connecticut's competitive market structure. This requirement seeks the recommended design of the resource portfolio used to secure power supply for customers which, for example, could include a mixture of purchases from the spot market and short-term, medium-term, and long-term contracts.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities' have concluded that there is no need for additional generation resources in Connecticut in the next decade, as discussed in Section II A, above.

The Distribution Utilities recommend that alternative power procurement structures be explored, such as longer-term power contracts, to stabilize and reduce the cost of the standard offer service. (Companies' IRP, Recommendation 2, page 46). They also recommend that contracting or generation ownership options be considered to mitigate the exposure to natural gas costs and usage. . (Companies' IRP, Recommendation 4, page 47).

The Distribution Utilities recommend that state regulatory authorities examine methods to maximize the use of demand-side management resources. (Companies' IRP, Recommendation 1, page 45).

Degree of Compliance: LOW

The Distribution Utilities have presented a planning study, but not a procurement plan. The Distribution Utilities characterize their work as a resource planning study and make clear that it is not a procurement risk management study (Companies' IRP, page 49).

The Distribution Utilities' four recommendation point to the need for further work by them or by others to develop procurement strategies and means pertaining to demand-side management, renewable energy, and standard offer service. However, the recommendations do not include proposals for specific procurement actions or programs.

IV. SECTIONS 51-D – PROCURMENT PLAN CONSIDERATIONS

Section 51 (D) specifies seven issue areas that are to be considered in the Procurement Plan. A Summary Scorecard for each of these component requirements is included in Appendix B of this report.

A. Approaches To Maximizing The Impact Of Demand-Side Measures

Description of the Requirement:

This provision calls for an assessment of maximum demand-side resources and consideration of approaches to obtaining that level of savings.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

High level strategies/approaches are identified in the plan: (a) "aim higher/go deeper," (i.e., strive for the highest efficiency levels in end use consumption that are cost-effective); (b) accelerate the retirement of inefficient customer systems; (c) integrate program design and delivery; and (d) integrate with other state-wide initiatives. No additional detail is provided in the report, but descriptions of these strategies can be found in the Conservation and Load Management Portfolio Plan, DPUC Docket No. 06-10-02, Scenario 2 (Zero load growth) Supplemental Filing by the Distribution Utilities, dated January 31, 2007:

- The Plan recommends that DSM be pursued more aggressively and that the ramp-up of more aggressive programs should begin in the near term.
- Appendix D of the Plan provides summaries of key residential and non-residential DSM programs designed to meet the aggressive goals of the DSM focus case.
- The Residential program portfolio addresses all of the key market segments and technologies -- Residential Lighting & Appliances, HVAC, Electric Water Heating, New Construction and Low Income and Direct Load Control. The Commercial and Industrial program portfolio is also comprehensive in its coverage of market segments and technologies including New Construction, Small Business, O&M, Codes & Standards, Market Transformation, Emerging Technologies and Load Response

Degree of Compliance: FULL

Program portfolios are comprehensive, and together with the Distribution Utilities Supplemental Filing referred to in (i) above represent a reasonable consideration of approaches to maximize the impact of DSM measures as required by the Public Act.

B. The Extent To Which Generation Needs Can Be Met By Renewable And Combined Heat And Power Facilities

Description of the Requirement:

This provision is included to assure that the planning process specifically investigate the potential for renewable resources or combined heat and power facilities to meet identified needs for generation.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities included an Appendix to their IRP which discusses their views on the current challenges in meeting the Connecticut and regional renewable portfolio standards. (Companies' IRP, Appendix E) The Distribution Utilities state that they did not conduct a regional renewable energy market study, indicating that such a study was beyond the scope of their work (Companies' IRP, page 49).

Due to the recent difficulties in securing Connecticut Class 1 renewable supplies, the Distribution Utilities include a recommendation a re-examination of the Connecticut renewable portfolio standard. (Companies' IRP, Recommendation 3, page 47).

Degree of Compliance: PARTIAL

The Renewable Energy appendix provides a discussion of information on the renewable project activity in Connecticut and the region generated by the Project 100 solicitations and the ISO New England Interconnection queue.

The Distribution Utilities do not provide any assessments of renewable resource potentials or estimated costs of renewable project development.

The Distribution Utilities do not provide any information on combined heat and power systems.

C. The Optimization Of The Use Of Generation Sites And Generation Portfolio Existing Within The State

Description of the Requirement:

This provision is included to assure that the planning process consider the future use of the existing generation facilities in Connecticut and the sites that have been or could be used for generation projects.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities conducted a screening analysis of the Connecticut generation units that have operated under a Reliability Must Run agreement with ISO-New England to assess the potential for retirement of these units. (Companies' IRP, Appendix A, page A-6). Using an analysis that considers the going-forward avoidable fixed O&M, the Distribution Utilities concluded that all of this generation would remain operational throughout the planning period. Based on this assessment, all of the need assessments and market analysis conducted by the Distribution Utilities for the IRP assumed no retirements of existing generation.

The Distribution Utilities' IRP does not address the utilization of generation sites and state that their IRP is .not a siting analysis for new generation capacity." (Companies' IRP, page 48.)

The Distribution Utilities included an assessment of the differences between market pricing and an assumed cost-of-service pricing for existing generation. This assessment indicated a substantial differential in cost and lead the Distribution Utilities to include a recommendation to explore alternative procurement approaches to improve the cost of supply to customers. (Companies' IRP, Recommendation 2, page 46).

Degree of Compliance: LOW

The Distribution Utilities' IRP does not include any assessment addressing the potential attrition of existing generation in Connecticut. As noted in Section II D above, the planning assessments did not consider environmental issues associated with existing generation other than compliance with the Regional Greenhouse Gas Initiative. The Distribution Utilities screening on going-forward costs assumed no need for investment for environmental controls or other costs or operating restrictions resulting from more stringent environmental standards.

The absence of an assessment of the plan under possible retirement scenarios is a limitation of this study. The large number of aging power plants in Connecticut has been an issue raised by ISO New England in its regional system planning process. Similarly, the CSC assessments of Connecticut's loads and resources have reported the magnitude of aging capacity.

D. Fuel Types, Diversity, Availability, Firmness Of Supply And Security And Environmental Impacts Thereof, Including Impacts On Meeting The State's Greenhouse Gas Emission Goals

Description of the Requirement:

This provision includes requirements for assessments of a number of performance measures of the power system pertaining to reliability, security, risk, and environmental performance.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities IRP features a modeling analysis which simulation the operation of the Connecticut and regional power system. This model is structured to provide a number of outputs which are used to assess many of the parameters of this system that would be used to measure performance (e.g., fuel mix, carbon emissions). (Companies' IRP, Appendix G)

The Company's IRP uses this model to examine several scenarios, such that a number of metrics of the system performance can be analyzed. (Companies' IRP, Appendix G).

Degree of Compliance: PARTIAL

The Company has sponsored a significant modeling analysis that provides assessments of many of the factors embodied in this requirement. The limited consideration of environmental factors other than greenhouse gas emissions and of existing unit retirements is reflected in the modeling results, as well.

E. Reliability, Peak Load And Energy Forecasts, System Contingencies And Existing Resource Availabilities

Description of the Requirement:

This provision includes requirements for assessments of a number of measures of generation and transmission system reliability.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities' assessments using forecasts of peak load and energy and the assessment of the need for generation are addressed in Sections II A, III A and III C above.

Degree of Compliance: PARTIAL

As noted in Section II A, the Distribution Utilities have addressed the forecasting requirements and the reliability requirements for the generation system.

However, *this assessment is limited in its treatment of important transmission issues*. As noted in Section III C, the Distribution Utilities' IRP does not address the transmission issues imbedded in this requirement. Large generation and transmission elements in Connecticut have given rise to needs for transmission projects and for local forward reserve markets. The issue of retirement of existing generation treatment is also not addressed.

F. Import Limitations And The Appropriate Reliance On Such Imports

Description of the Requirement:

This provision relates to the capability of the transmission system to allow for power imports, principally from New England, to provide Connecticut consumers with a reliable and cost-effective power supply.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities' conducted an assessment of the ISO-New England capacity market to test the need for added local sources. The results of their assessment indicates that aggressive demand-side management, no retirements, and completion of transmission under construction will resolve the significant bottlenecks in Southwest Connecticut and that added capacity needed in New England need not be in Connecticut. (Companies' IRP, page 40)

The Distribution Utilities' market modeling of Connecticut and New England included detailed representation of transmission transfer limits. This analysis found no significant congestion affecting pricing. (Companies' IRP, page 40)

Degree of Compliance: FULL

The Distribution Utilities modeling of the capacity market and the energy markets provides significant analysis to address this requirement.

G. The Impact Of The Procurement Plan On The Costs Of Electric Customers

Description of the Requirement:

This requirement is very similar to the requirement in Section 51 c.4, described in Section III D. and thus discussed within this report under that Section III D.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

This requirement is very similar to the requirement in Section 51 c.4, described in Section III D. and thus discussed within this report under that Section III D.

Degree of Compliance: PARTIAL

This requirement is very similar to the requirement in Section 51 c.4, described in Section III D. and thus discussed within this report under that Section III D.

V. SECTION 51-A COMPREHENSIVE PROCUREMENT PLAN

Subsection A of Section 51 establishes the requirements for the utilities, in consultation with the CEAB, to conduct a review of the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources. In this section, we determine the extent to which the Distribution Utilities' IRP contains the elements of a procurement plan.

A. Review The State's Energy And Capacity Resource Assessment

Description of the Requirement:

This requirement encompasses the assessments addressed in Sections II A and III A.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

See discussion in Sections II A and III A, above.

Degree of Compliance: FULL

See discussion in Sections II A and III A, above.

B. Develop A Comprehensive Plan For The Procurement Of Energy Resources

Description of the Requirement:

This overarching requirement in Section 51 is seeking a planning result that provide a sound assessment of the resource needs and a set of strategies and recommended actions for implementation of the plan.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities have prepared an analysis and report which they describe as an Integrated Resource Plan. They explain that this IRP is limited in that it:

1. contains limited analysis related to transmission
2. is not a siting analysis for new generation
3. is not a procurement risk management study
4. is not a renewable energy market assessment study

Based on the IRP, the Distribution Utilities make four recommendations:

1. Maximize the use of demand side management
2. Explore other power procurement structures, such as long-term contracts
3. Evaluation the Connecticut Renewable Portfolio Standard
4. Consider potential ways to mitigate the exposure to the price and availability of natural gas.

Degree of Compliance: LIMITED

The Distribution Utilities have provided a substantial set of assessments of generation and demand-side resources in a resource planning report, providing meaningful and considered analysis responsive in whole or in part with most of the assessment requirements set forth in Section 51.

The Distribution Utilities have not offered a Procurement Plan as part of this filing. The recommendations point to further assessments in important areas resulting from the Distribution Utilities' findings. In particular, the Distribution Utilities are recommending increased demand side management and alternative power supply contracting, however the Distribution Utilities' IRP does not contain recommendation on approaches and does not include action plans for implementation of those recommendations.

VI. CONSIDERATIONS FOR NEXT STEPS

Section 51 (e) specifies a process for review, modification, and approval of the Distribution Utilities' Procurement Plan and a subsequent review process at the DPUC. The relevant portions of this subsection for this 2008 review are as follows:

- *The board, in consultation with the regional independent system operator, shall review and approve or review, modify and approve the proposed procurement plan as submitted not later than one hundred twenty days after receipt.*
- *The electric distribution companies shall provide any additional information requested by the board that is relevant to the consideration of the procurement plan.*
- *The board shall submit the reviewed procurement plan, together with a statement of any unresolved issues, to the Department of Public Utility Control.*
- *The department shall consider the procurement plan in an uncontested proceeding and shall conduct a hearing and provide an opportunity for interested parties to submit comments regarding the procurement plan. Not later than one hundred twenty days after submission of the procurement plan, the department shall approve, or modify and approve, the procurement plan.*

The 120 day period for the CEAB review and approval process will conclude on or about April 30, 2008.

Based on our review of the Distribution Utilities' IRP, we offer the following suggestions for the CEAB to consider in deciding an approach to this 2008 review, modify, and approval process.

A. Working With The Distribution Utilities

We offer the following list of issues for the CEAB to consider for action during the remainder of the CEAB review process. This list is neither prioritize nor exhaustive. It is intended to facilitate the CEAB's discussion and prioritization process in framing the direction for the review process.

1) The Distribution Utilities' Four Recommendations

The Distribution Utilities have included four recommendations in their IRP, paraphrased as follows (See Companies IRP, pages 45 – 47):

i. Maximize the use of Demand-side management
ii. Explore other power procurement structures such as longer term power contracts
iii. Evaluate the structure and costs of Connecticut's RPS
iv. Consider ways to mitigate consumers' exposure to the price and availability of natural gas.

Each of these recommendations is in the form of additional investigation and development. CEAB's approval will need to consider whether to approve and/or modify these recommendations.

2) DSM Strategy and Implementation

Maximum DSM implementation is an explicit focus of Section 51 and is a primary recommendation of the Distribution Utilities. DSM is, in fact, the only resources that the Distribution Utilities are recommending for procurement in their IRP. An improved plan for this activity could be a focus of this review process.

3) Environmental Regulations Assessment

The Distribution Utilities modeling provides a resource to assess RGGI issues and related greenhouse gas emission questions. Action areas could include addition assess of resources in this area.

We determined that the IRP does not address the implication of ozone nonattainment and increasingly stringent requirement that will affect the older oil-fired steam units, I particular. Further work to define the risk factors for this capacity could explore to better assess the risk of loss of existing generation.

4) Transmission Planning Integration

The Distribution Utilities' IRP has not been integrated with the transmission planning process. The Distribution Utilities recommendations on DSM will, if successful, have a material affect on load growth. The DSM planning may be influenced by the level of potential avoided T&D and the Transmission Plans may benefit from a better assessment of future DSM.

5) Renewable Portfolio Standards

The Distribution Utilities' IRP uses recent market results to question the ability of the renewable market in Connecticut to meet RPS targets. This area may warrant further assessment. It is also a recommendation in the Distribution Utilities' IRP.

6) Long Term Contracting

The Distribution Utilities' IRP recommends exploring longer term contracting options to mitigate market price and volatility exposure. This appears to be central to the procurement planning process and may warrant further assessment.

B. Consultation Issues with ISO-New England

Section 51 calls for CEAB consultation with ISO New England on the Distribution Utilities' IRP. The following are a list of issues that, if CEAB wishes to pursue, would be particularly beneficial to obtain input from ISO New England.

1) Forward Capacity Market Auction

The first FCM auction is schedule for early February. The results from that auction may have some direct affect on units that will be operating in Connecticut. In addition, an assessment of the clearing price, the fate of renewable projects and demand response project will provide some insight into the market for and the potential of these resources.

2) Congestion Assessment

The Distribution Utilities' IRP includes a finding that congestion is being effectively mitigated in Connecticut through added transmission and generation. Given the requirements to address Federally Mandated Congestion Charges, this may be an area where consultation with ISO New England could provide some added information.

Appendix A

Full Text of Section 51 of Public Act No. 07-242

An Act Concerning Electricity and Energy Efficiency

Sec. 51.

(a) The electric distribution companies, in consultation with the Connecticut Energy Advisory Board, established pursuant to section 16a-3 of the general statutes, as amended by this act, shall review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.

(b) On or before January 1, 2008, and annually thereafter, the Distribution Utilities shall 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.

(c) 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 basis with non demand-side resources. The procurement plan shall specify (1) the total amount of energy and capacity resources needed to meet the requirements of all customers, (2) the extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs, (3) needs for generating capacity and transmission and distribution improvements, (4) how the development of such resources will reduce and stabilize the costs of electricity to consumers, and (5) the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources.

(d) The procurement plan shall consider: (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.

(e) The board, in consultation with the regional independent system operator, shall review and approve or review, modify and approve the proposed procurement plan as submitted not later than one hundred twenty days after receipt. For calendar years 2009 and thereafter, the board shall conduct such review not later than sixty days after receipt. For the purpose of reviewing the plan, the Commissioners of Transportation and Agriculture and the chairperson of the Public Utilities Control Authority, or their respective designees, shall not participate as members of the board. The electric distribution companies shall provide any additional information requested by the board that is relevant to the consideration of the procurement plan. In the course of conducting such review, the board shall conduct a public hearing, may retain the services of a third-party entity with experience in the area of energy procurement and may consult with the regional independent system operator. The board shall submit the reviewed procurement plan, together with a statement of any unresolved issues, to the Department of Public Utility Control. The department shall consider the procurement plan in an uncontested proceeding and shall conduct a hearing and provide an opportunity for interested parties to submit comments regarding the procurement plan. Not later than one hundred twenty days after submission of the procurement plan, the department shall approve, or modify and approve, the procurement plan. For calendar years 2009 and thereafter, the department shall approve, or modify and approve, said procurement plan not later than sixty days after submission.

(f) On or before September 30, 2009, and every two years thereafter, the Department of Public Utility Control shall report to the joint standing committees of the General Assembly having cognizance of matters relating to energy and the environment regarding goals established and progress toward implementation of the procurement plan established pursuant to this section, as well as any recommendations for the process.

(g) All electric distribution companies' costs associated with the development of the resource assessment and the development of the procurement plan shall be recoverable through the systems benefits charge.

Appendix B

Summary Scorecard

Plan Compliance with the Requirements of PA 07-242

Section 51(b): January 1, 2008 Plan Contents

Section 51, Part (b): On or before January 1, 2008, the Distribution Utilities shall submit to the Connecticut Energy Advisory Board an assessment of:	
Requirement	**Degree of Compliance**
1) The energy and capacity requirements of customers for the next 3, 5, and 10 years.	**FULL**
2) The manner of how best to eliminate growth in electric demand.	**PARTIAL**
3) How best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods.	**PARTIAL**
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.	**LOW**
5) Energy security and economic risks associated with potential energy resources.	**PARTIAL**
6) The estimated lifetime cost and availability of potential energy resources.	**PARTIAL**

Appendix B

(page 2 of 3)

Summary Scorecard

Plan Compliance with the Requirements of PA 07-242

Section 51(c): January 1, 2008 Plan Contents

Section 51, Part (c): 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 basis with non demand-side resources. The procurement plan shall specify:

Requirement	Degree of Compliance
1) The total amount of energy and capacity resources needed to meet the requirements of all customers.	**FULL**
2) The extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs.	**FULL**
3) Needs for generating capacity and transmission and distribution improvements.	**PARTIAL**
4) How the development of such resources will reduce and stabilize the costs of electricity to consumers.	**PARTIAL**
5) The manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources.	**LOW**

Appendix B

(page 3 of 3)

Summary Scorecard

Plan Compliance with the Requirements of PA 07-242

Section 51(d): January 1, 2008 Plan Contents

Section 51, Part (d): The procurement plan shall consider	
Requirement	**Degree of Compliance**
1) Approaches to maximizing the impact of demand-side measures.	**FULL**
2) The extent to which generation needs can be met by renewable and combined heat and power facilities.	**PARTIAL**
3) The optimization of the use of generation sites and generation portfolio existing within the state.	**LOW**
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.	**PARTIAL**
5) Reliability, peak load and energy forecasts, system contingencies and existing resource availabilities.	**PARTIAL**
6) Import limitations and the appropriate reliance on such imports.	**FULL**
7) The impact of the procurement plan on the costs of electric customers.	**PARTIAL**

APPENDIX D

CEAB March Letter to Energy and Technology

—Status Report Attachment to March Letter
—Process Report Attachment to March Letter

2008 Comprehensive Plan for the
Procurement of Energy Resources

Prepared by:
The Connecticut Energy Advisory Board

CEAB
Connecticut Energy Advisory Board

Approved August 1, 2008

CEAB
Connecticut Energy Advisory Board
WWW.CTENERGY.ORG

May 7, 2008

The Honorable John W. Fonfara
The Honorable Steve Fontana
Energy and Technology Committee
Legislative Office Building, Room 3900
Hartford, CT 06106

Dear Senator Fonfara and Representative Fontana:

The Connecticut Energy Advisory Board ("CEAB") is providing a status report on Section 51 of Public Act 07-242, An Act Concerning Electricity and Energy Efficiency ("the Act"). The Act sets forth the requirements for an annual Integrated Resource Plan ("Plan") to be prepared by the electric distribution companies ("Companies"), and subsequently reviewed and approved by the CEAB and the Department of Public Utility Control ("DPUC"). More specifically, the CEAB is conveying information on activity to date as well as our intended path to approving a Plan that satisfies the statutory requirements and merits consideration by the DPUC.

As described in the attached status report, the CEAB received the Distribution Utilities' Plan on January 1, 2008; performed a preliminary assessment for statutory compliance; issued the Plan for public comment; and, conducted a public hearing on February 11, 2008. Overall, the CEAB received substantial, and in many cases detailed, written comments from a broad spectrum of interested persons and organizations. The status report includes a high level review of comment on key issues, from strong support for demand-side management to real concern over certain Plan assumptions. Participants generally conclude that the Plan does not satisfactorily and substantially conform to the statutory criteria. The CEAB agrees that a number of important issues have not been adequately addressed.

Although the Distribution Utilities prepared substantial analysis within the confines of an aggressive timetable, the Plan requires additional data, considerable refinement on core issues and greater specificity on how to accomplish goals. To accomplish the constructive, comprehensive Plan requirements, we have begun to execute a course of action to substantially modify the Plan as permitted by statute. Through this process, the CEAB will ensure that the 2008 Plan complies with the statutory framework, satisfactorily addresses central resource planning issues and has sufficient specificity to lead to action. In short, through a streamlined stakeholder process, the CEAB will gather relevant data, such as renewable resource availability and generating unit retirements, conduct further analysis, and then modify the Plan. Once the CEAB has approved a modified Plan it will be forwarded to the DPUC for consideration. The attached Procurement Plan Process for 2008 and 2009 provides additional details.

The CEAB believes strongly that this foundational work on the initial 2008 Plan will result in a planning process and template that will expedite future plans. We have outlined an ambitious timeline to accomplish this goal and recognize the need for the full support of a number of partners to assemble and evaluate the additional information necessary to develop the comprehensive plan we believe the Act contemplates. We are particularly pleased that the Distribution Utilities have offered to provide further information and modeling and that other participants have expressed a similar willingness to help move the Plan forward.

The CEAB appreciates the opportunity to provide an update on our work and would be pleased to provide any additional information that you would find helpful.

Sincerely,

John A. Mengacci
Chairman, CEAB
Under Secretary, OPM

2008 Integrated Resource Plan

CEAB Review Status Report

I. Introduction

The Connecticut Light & Power Company and the United Illuminating Company (together, "the Distribution Utilities") submitted *An Integrated Resource Plan for Connecticut* ("the Plan") to the Connecticut Energy Advisory Board ("CEAB") on January 1, 2008 pursuant to Section 51 of Public Act No. 07-242, An Act Concerning Electricity and Energy Efficiency ("Section 51"). The Distribution Utilities prepared the Plan together with their consultant, The Brattle Group, and presented the Plan to the CEAB on January 4, 2008.

Section 51 sets forth constructive and comprehensive requirements for the Plan.[87] Additionally, it established aggressive time frames for the Plan's initial preparation by the Distribution Utilities and subsequent review by the CEAB. Section 51 requires the CEAB, in consultation with the Independent System Operator – New England (ISO New England), to review and approve or to review, modify and approve the Distribution Utilities' Plan. Once approved, the CEAB must submit it, together with a statement of any unresolved issues, to the Department of Public Utility Control ("DPUC") by April 30, 2008.

This document provides a status report on the CEAB's process on the Plan to date and a broad summary of public input on the Plan thus far, together with the CEAB's preliminary observations. For purposes of this summary, the comments are characterized broadly in order to provide a general view and do not reflect all substantive points on any one issue or by any particular commentator.

II. CEAB Review Process to Date

Preliminary Assessment of Statutory Compliance. The CEAB requested its technical consultant, La Capra Associates, to review the Plan and perform a preliminary assessment of the

[87] At page 48-49 of the Plan, the Distribution Utilities made clear that there are limitations to their Plan's analysis. As submitted to the CEAB, the Plan: Contains only limited analysis related to transmission; is not a siting analysis for new generation capacity; is not a procurement risk management study; and, is not a regional renewable energy market study.

Additionally, at page 2 of the Plan, the Distribution Utilities set forth other limitations to their analysis, many of which they suggest can be addressed in other venues or in subsequent years' Plans. More specifically, the Distribution Utilities state that the study: was not intended to provide a cost/benefit analysis of transmission options; did not compare the economics of transmission vs. generation vs. demand-side options; and, does not constitute a transmission reliability assessment.

extent to which the Plan provides the information requirements set forth in Section 51. The purpose of the preliminary assessment was to provide the CEAB a starting point for its further consideration of the Plan. The review included a day-long technical discussion between representatives of the CEAB, La Capra and the Distribution Utilities. When the preliminary assessment was completed on January 28, 2008, it was provided to the CEAB and then discussed at its regularly scheduled meeting on February 1, 2008. The CEAB also made it available to interested persons.

The Distribution Utilities submitted a joint letter to the CEAB on February 8, 2008 in which they offered assistance to inform and enhance the CEAB's review of the Plan. Specifically, the Distribution Utilities offered to answer the CEAB's questions regarding the Plan's assumptions, analytical methodologies, results and conclusions and to make adjustments to the Plan's modeling. The CEAB appreciates the Distribution Utilities offer. We believe close consultation and collaboration between CEAB and the Distribution Utilities is essential to successfully advancing the planning process. The CEAB and the Distribution Utilities will build on the work that the Distribution Utilities have done to date to develop needed modifications to the 2008 Plan that the CEAB will approve for consideration by the DPUC.

Public Input. On January 11, 2008, the CEAB issued a request for public comment on the Distribution Utilities' Plan and asked for submission by February 7, 2008. Specifically, the CEAB requested comment on the way in which the Plan meets the statutory criteria, and/or the specific ways in which the Plan should be modified to better conform to the statutory requirements. Twenty entities submitted written comments.[88] Some comments focused on single elements of the Plan, such as demand-side management ("DSM") and others provided comprehensive evaluations of the Plan. In addition, more than forty individuals sent electronic mail to the CEAB to convey their views of the Plan; most supported the Plan's recommendations concerning demand side management ("DSM") measures. Overall, the CEAB received substantial and in many cases detailed written comments from a broad spectrum of interested persons and organizations.

On February 11, 2008, the CEAB held a public hearing on the Plan in Hartford Connecticut, consistent with Section 51. More than a dozen persons spoke at the Public Hearing. Nearly all speakers had also submitted written comments.[89] In addition, The Brattle Group, the Distribution Utilities' consultant, offered comments and indicated it is interested in engaging the CEAB in

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[88] AARP; Attorney General; American Lung Association; Connecticut Clean Energy Fund; CMEEC; Clean Water Action; David Jackson; Elizabeth Beiter Oldfield; Energy Conservation Management Board; Environment Northeast; FirstLight; Robert Fromer; Lee Hebert; League of Women Voters of Connecticut; Milford Environmental Concerns Coalition; New England Power Generators Association; Northeast Energy Efficiency Partnerships; Noble Environmental Power; NRG; Constellation/Retail Energy Supplies Association; UTC.

[89] Direct Energy spoke at the public hearing but did not submit written comment; Direct is, however, a member of RESA, which submitted written comments.

continued dialogue on the Plan.[90] The public hearing was transcribed so that members of the CEAB whose schedules prevented attendance were able to review the comments provided verbally.

III. Public Comment Summary

The CEAB sets forth below the Plan's four Recommendations with a broad description of public comments on each followed by CEAB's initial observations. In addition, because public comment highlighted several core elements of the Plan to be of common concern, we describe and offer brief observations on those. They include: overall statutory compliance; transmission analysis; assumptions concerning retirement of in-state generators; availability and advancement in technology; and, return to cost of service.

A. COMPANIES' RECOMMENDATION No. 1 Maximize the use of demand side management within practical, operational and economic limits, to reduce peak load and energy consumption

The first Recommendation in the Distribution Utilities' Plan is to maximize the use of demand- side management ("DSM") within practical, operation and economic limits to reduce peak load and energy consumption received particularly broad support.[91] The Energy Conservation and Management Board ("ECMB") stated that it and its consultants worked closely with the Distribution Utilities on the DSM portion of the Plan. The ECMB concluded that the Plan established ambitious, achievable energy and peak demand savings targets for DSM programs through 2018 as part of overall effort to achieve all cost-effective energy efficiency and demand reduction. According to the ECMB, the only "economic limit" that should be applied for "maximizing the use of DSM" is demonstration of conservation and load management program cost-effectiveness. The current "economic limit" constraining the such programs, program funding levels, must be addressed by increasing funding for the programs in 2008 and future years.

Many commentators encouraged immediate implementation and funding of DSM irrespective of whether other central elements of the Plan are ready to move forward at this time. The vast majority of individuals (speaking as citizens rather than as representatives of an organization) strongly supported this element of the Plan. One commentator observed that increasing DSM is the only aspect of the Plan that involved immediate action: all others called for exploration, evaluation or consideration.[92]

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90 See, Transcript dated February 11, 2008 at 79.

91 *See*, American Lung Association cover letter; CMEEC at 3; Clean Water Action at 2-3; ECMB at 1 -2; Environment Northeast at 1, 7-8; NEEP at 1-3. In addition, the vast majority of the individuals who sent e-mails to the CEAB focused exclusively on, and in strong support of, DSM.

92 *See*, Environment Northeast at 3.

Other commentators expressed concern that the Plan's DSM goals are overly aggressive, lack cost-effectiveness analysis, cost-comparisons to other resources and a feasibility assessment.[93] Several commentators stated that the Plan overstates the ability of DSM to maintain reliability within practical and economic limits.[94] Additionally, one commentator observed that the Plan did not address potential funding mechanisms to implement DSM, including those that would complement current ratepayer funded programs to minimize ratepayer costs, such as building codes or appliance standards or combined heat and power.[95]

> **CEAB Observation**: Section 51(c) directs that resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible. In this regard, the Distribution Utilities' DSM recommendation is consistent with the statutory directive. And, the Plan contains a meaningful assessment of the DSM potential needed to eliminate growth in energy in demand.[96] More work, however, needs to be done on how best to accomplish the goal and to ensure the customer cost impact of demand-side resources are reviewed on an equitable basis with non-demand side resources. With regard to the suggestion that the DSM move forward immediately irrespective of other unresolved issues in the Plan, we believe the level of cost-effective DSM should be identified in the context of the overall Plan.

B. COMPANIES' RECOMMENDATION No. 2 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.

Several commentators expressed concern with the distribution companies entering long-term contracts on a cost of service basis and some suggested that approach would increase costs to customers by placing investment and other risks on them.[97] Several commentators suggest further inquiry issues associated with long-term power contracts. CMEEC recommended considering negotiating contracts that could be available to all utilities in state rather than a system in which utilities compete for long term cost of service contracts.[98] In connection with renewable energy resource development, several commentators stated that

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[93] *See*, Firstlight at 5; New England Power Generators Association at 11; NRG at 7-10.

[94] *See*, Firstlight at 6; New England Power Generators Association at 11.

[95] *See*, AARP at 3, 12.

[96] The Plan's DSM section is one of the more developed Plan elements and the Distribution Utilities' work with the ECMB may have facilitated this end; working with other entities on less developed Plan elements may achieve similar results more broadly.

[97] *See*, Constellation/RESA at 4-6; New England Power Generators Association at 12-13.

[98] *See*, CMEEC at 4.

long-term power purchase contracts for renewable energy resources would be beneficial and offer the potential to lower prices of renewable portfolio standard compliance.[99]

> **CEAB Observation**: The potential options set forth in the Plan concerning alternative procurement methods and a hypothetical cost of service regime should be viewed against the Distribution Utilities' express statement that the Plan is not a procurement risk management study. The Plan makes clear that it does not formally address physical or financial portfolio risk management or hedging considerations and that its recommendations to alleviate some procurement constraints are based primarily on potential benefits implied.[100] Given these limitations and the Plan's lack of specificity relative to specific plans or actions for resource procurement, the CEAB believes this area requires further development.[101]

C. COMPANIES' RECOMMENDATION No. 3. Evaluate the structure and cost of Connecticut's renewable portfolio standard in the context of a regional re-examination of the goals and costs of similar policies in New England.

Several commentators took exception to the Plan's lack of analysis of renewable resource availability or suggested the Plan's assumptions, and the resulting recommendation concerning the renewable portfolio standard, is problematic.[102] No commentators suggested the Plan's renewable resource analysis was comprehensive. However, one commentator supported the recommendation to review the state's renewable policies in the regional context.[103] Another suggested the proper question is how to achieve current renewable portfolio standard requirements, rather than how to change the requirements.[104] Several commentators observed that the Plan included no assessment of in-state renewable potential or advancements in renewable technologies.[105]

The Connecticut Clean Energy Fund ("CCEF"), through analysis performed by Sustainable Energy Advantage, LLC, states that the Plan's analysis on renewable resources omits several important categories of eligible existing and expected renewable energy supply, which when

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99 *See*, CCEF at 15; Clean Water Action at 5;Environment Northeast at 8-9.

100 *See*, Plan at pages 48-49.

101 Pursuant to Section 104 of Public Act 07-242, the DPUC is currently examining supply procurement options. See, Docket No. 07-06-58, *DPUC Report to the Connecticut General Assembly on Standard Service Procurement* and Docket No. 06-01-08RE01, *DPUC Development and Review of Standard Service and Supplier of Last Resort Service – Plan Approval – Bilateral Contracts Outside of Auction*.

102 *See*, AARP at 18-19; CCEF at, Environment Northeast at 8-9; Noble at 2; NRG at 17; UTC at 2.

103 *See*, CMEEC at 4-5.

104 *See*, Environment Northeast at 8.

105 *See*, AARP at 19; UTC at 2-3; NRG 17.

accounted for, suggests the Plan's renewable assumptions are not likely to occur.[106] According to that analysis, for Connecticut Class I renewables, there is likely to be a very modest, if any, renewable energy credit shortage, resulting in limited alternative compliance payments over the next several years. The CCEF also sets forth specific recommendations to improve Connecticut's posture relative to Class I renewable portfolio standard compliance, such as allowing banking of renewable energy credits as other New England states allow.

> **CEAB Observation**: The Plan's recommendation relative to renewable resources and RPS compliance would benefit from additional information and market analysis such as that provided by the CCEF in the same way that the Plan's DSM analysis benefited from the constructive input of the ECMB. As noted above, the Distribution Utilities' stated that the Plan's recommendation to re-examine the state's RPS was not presented in connection with a thorough examination of the region's renewable energy market and that additional analysis should be pursued.[107] Moreover, as a general matter, the suggestion that the question of how the state can meet the current Class I renewable portfolio standard requirements be fully explored prior to considering how to modify it makes sense.[108] Further work in this area would also enable the Plan to better meet Section 51's requirement to assess the impact of environmental standards and how different resources could help achieve them, as well as the extent to which the state's generation needs can be met by renewable (and combined heat and power) facilities.

D. COMPANIES' RECOMMENDATION No. 4 Consider potential ways to mitigate exposure of Connecticut consumers to the price and availability of natural gas.

AARP, through analysis prepared by Synapse Energy Economics, Inc., stated that the Plan did not provide a plan to mitigate the risk of natural gas and that had the Plan complied with the seven statutory requirements the Plan would mitigate the exposure of natural gas price and availability risks.[109] Another commentator suggested that the electric prices in both restructured and non-restructured markets have increased as prices are tied to the price of natural gas and solutions should be in the form of permitting and siting improvements, not changes to market structure. [110] The Attorney General said the state should break the link between natural gas prices and electricity prices and recommends a generator refund

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[106] *See*, CCEF at 4.

[107] *See*, Plan at 49.

[108] Pursuant to Section 71 of Public Act 07-242, the DPUC is examining issues associated with long term contracts for renewable energy credits. See, Docket No. 07-06-61, *DPUC Examination of Electric Distribution Company Contracts for Renewable Energy Credits*.

[109] *See*, AARP at 19-20.

[110] *See*, New England Power Generators Association at 13.

mechanism.[111] Several commentators noted the connection between increased renewable resources and natural gas price mitigation.[112]

CEAB Observation: The means to mitigate various risks associated with reliance on natural gas are interconnected with several core aspects of the Section 51. For example, the Distribution Utilities' Plan considered new nuclear and coal facilities and alternative ownership arrangements for generating units. In our view, Section 51 contemplates further development of comprehensive ways to mitigate natural gas risks beyond those included in the Plan. The Distribution Utilities' willingness to provide further analysis will be helpful to advancing this aspect of the Plan.

E. OVERALL STATUTORY COMPLIANCE

Most commentators that assessed the Plan's overall compliance with statutory requirements concluded that the Plan does not conform. [113] In fact, no commentator that offered an assessment of the IRP's overall compliance with the statute opined that the Plan met the statutory requirements. However, on the issue of the Plan's compliance with the DSM segment of the statute, there was strong support for the Plan.[114]

CEAB Observation: In general, we do not believe the Plan satisfactorily conforms to the statutory criteria. While the Distribution Utilities prepared substantial analysis on an aggressive schedule, the Plan requires incorporation of further data (for example, on retirement assumptions, renewable resource availability, combined heat and power penetration and an energy security assessment associated with potential energy resources as set forth in Section 51(b)(5)), considerable refinement on some core issues and greater specificity on how to accomplish goals.

We are confident that the regulatory framework need not preclude or inhibit preparation of a comprehensive integrated resource plan that accounts for various plausible scenarios, including scenarios concerning resources or assets that the Distribution Utilities do not own or otherwise control. As one example, that the Distribution Utilities do not own generating assets in Connecticut does not prevent alternative planning analysis that incorporates reasonable retirement assumptions. We believe further work on the Plan will benefit from continued contributions from the Distribution Utilities on the full scope of issues and from input from other participants.

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[111] *See*, Attorney General at 4.

[112] *see*, AARP at 19; Noble at 4.

[113] *See*, AARP at 2; Firstlight at 4; New England Power Generators Association at 3; NRG at 3-4.

[114] *See*, ECMB at 2-3; Environment Northeast at 7-8; e-mailed correspondence

F. TRANSMISSION ANALYSIS

Several commentators considered the Plan's lack of any analysis concerning transmission resources to be problematic.[115] In general, these commentators observed that the Plan assumed the proposed New England East West Solution ("NEEWS") project goes forward, yet offered no cost or comparative analysis of NEEWS and alternative resource options.[116] No commentator suggested that the Plan's approach to transmission was comprehensive or otherwise in conformance with the statute.

> **CEAB Observation**: As noted above, the Distribution Utilities emphasized the Plan's transmission resource approach was purposeful: it was not intended to provide a cost/benefit analysis of transmission options; it did not compare the economics of transmission vs. generation vs. demand-side options; and, it does not constitute a transmission reliability assessment. [117]
>
> The Plan must incorporate transmission planning in order to achieve an integrated view of resources consistent with Section 51.[118] For example, the Plan's recommendation on DSM, assuming it is fully funded and implemented, would materially affect load growth. DSM planning may be influenced by the level of potential avoided transmission and distribution plant and, conversely, transmission plans may benefit from an accurate assessment of planned DSM. The requirement for an assessment of demand-side resources on equal footing with non demand-side resources should include transmission and distribution resources. The CEAB anticipated the Plan it received from the Distribution Utilities would integrate transmission planning; further work to develop effective and useful comprehensive analysis of all resource options will require transmission-related information. The Distribution Utilities' offer to provide additional information to assist the CEAB's review will be constructive in this regard.

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115 *See*, Clean Water Action at 1; Firstlight at 6-7; New England Power Generators Association at 7; NRG at 13-15.

116 *See*, Clean Water Action at 1; Firstlight at 7; NRG at 13.

117 *See*, Plan at page 2.

118 CMEEC has previously suggested to the CEAB that proposed transmission projects are properly considered in the context of the state's integrated resource planning effort. *See*, Comments submitted to the CEAB by CMEEC on August 3, 2007.

ASSUMPTION CONCERNING IN-STATE GENERATOR RETIREMENTS

Several commentators took strong exception to the Plan's assumption that there will be no generator retirement in Connecticut given the vintage of Connecticut's generating units, expected environmental regulations, and the conclusion of reliability must run agreements in 2010.[119] NRG, for example, said the Plan's retirement assumption is implausible and that the Plan must take into account the potential of older generating units to require environmental or other upgrades to avoid retirement, and evaluate whether refurbishment of the units would be a viable resource solution to achieve environmental standards and minimize ratepayer costs.[120] No commentators suggested that the IRP's retirement assumptions were reasonable.

CEAB Observation: The Plan's absence of assessments under possible generator retirement scenarios is a real limitation. The large number of aging power plants in Connecticut has been an issue raised by ISO New England in its regional system planning process. Similarly, the Connecticut Siting Council assessments of Connecticut's loads and resources have reported the magnitude of aging capacity in this state. In consultation with generator owners, the Plan will benefit from better information on the risk of loss of existing in-state generation and associated issues. The Distribution Utilities' willingness to perform additional modeling runs will enable this work to be accomplished most efficiently.

G. AVAILABILITY AND ADVANCEMENTS IN TECHNOLOGY

Several commentators noted that the Plan did not recognize technology availability and advancements and pointed to technologies such as combined heat and power that can reduce dependency on natural gas and provide cooling in peak summer periods. [121] One commentator took exception to the fact that the Plan did not recognize evolving coal technology that could mitigate climate change.[122] No commentator suggested the Plan adequately considered technology availability and advancements.

CEAB Observation: Section 51(a) contemplates that the Plan will review a broad range of energy resources, such as combined heat and power and other emerging energy technologies to meet projected customer requirements. The Plan needs further work in this area.

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119 *See*, Firstlight at 10; NRG at 5-7; New England Power Generators Association at 6-7.

120 *See*, NRG at 5-7.

121 *See*, AARP at 3, 19; Clean Water Action at 5; NRG at 17, UTC at 2.

122 *See*, NRG at 17-18.

H. RETURN TO COST OF SERVICE

Several commentators supported the notion of some form of return to cost of service regulation or other fundamental market changes, asserting that retail competition has failed.[123] Several commentators expressed concern with the Plan's cost of service recommendations, suggesting, for example, that they are beyond the scope of the statute, provide no value to an impartial evaluation of energy resources, or are based on unrealistic assumptions that result in flawed analysis.[124]

> **CEAB Observation**: Overall, because the statute contemplates the Plan will be implemented, the CEAB believes the Plan it approves should generally fit within the state's current statutory framework to enable implementation. In any event, in this case, the Plan's hypothetical Cost of Service regime observation was offered without comment or a plan on how assets would be acquired at Cost of Service.

123 *See*, AARP cover letter; Attorney General at 3 and 5.

124 *See*, New England Power Generators Association at 9; RESA/Constellation at 2.

CONNECTICUT PROCUREMENT PLAN

PROCESS PROPOSAL FOR 2008 AND 2009 PLANS

I. Introduction

The Connecticut Light & Power Company and the United Illuminating Company (together, "the Distribution Utilities") submitted *An Integrated Resource Plan for Connecticut* ("the Plan") to the Connecticut Energy Advisory Board ("CEAB") on January 1, 2008 pursuant to Section 51 of Public Act No. 07-242, An Act Concerning Electricity and Energy Efficiency ("Section 51"). The Distribution Utilities prepared the Plan together with their consultant, The Brattle Group and presented the Plan to the CEAB on January 4, 2008.

In January 2008, the CEAB solicited public comment on the Plan and retained its own consultants to conduct a preliminary review of the Plan for compliance with the requirements set forth in Section 51.[125] The CEAB also received a substantial body of written comments on February 7, 2008 and, at a public hearing on February 11, 2008, heard additional comment on the Plan.[126]

Based on this review of the Plan, it is clear that the Plan is not fully developed as contemplated in Section 51 and a number of important issues have not been adequately addressed. In its current form, the Plan cannot be approved by the CEAB and, further, the CEAB concludes that substantial modification is necessary before such approval can be issued.[127] Based on the comments received and the CEAB's own review, the CEAB concludes that there is a substantial opportunity to address many of the deficiencies in the Plan with information that is available from market participants or other stakeholders in the process. The CEAB's consideration of the Plan to date and the sentiments expressed through public comment underscore the importance of this planning process for Connecticut, and the need for a sound Procurement Plan as contemplated in Section 51.

Section 51 established a planning process beginning with this 2008 Plan and annually thereafter. The statute recognized that the first cycle of this process would take longer, and therefore allows 120 days for the CEAB review and 120 days for the DPUC review. In subsequent years, Section 51 calls for sequential 60 day reviews by the CEAB and the DPUC. In light of the deficiencies in the Plan received, it is now apparent that this first review cycle will require more time to develop a substantially conforming 2008 Procurement Plan. This work in 2008 will also establish the foundation for a successful and more efficient planning process in future years.

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[125] *Initial Review of the Integrated Resource Plan for Connecticut for Compliance with the Requirements in Section 51 of Public Act No. 07-242*, prepared by La Capra Associates for the Connecticut Energy Advisory Board, January 28, 2008.

[126] *See*, 2008 Integrated Resource Plan, CEAB Status Report, adopted by the CEAB March 7, 2008.

[127] Under Section 51, the CEAB is required to review the 2008 Plan and either approve the Plan or modify and approve the Plan for submission to the DPUC within 120 days.

II. 2008 Procurement Planning Process Objectives

In light of the conclusion that the 2008 Plan needs substantial improvements and the broad agreement about the importance of this planning effort to the State, the CEAB is executing a scope of work to modify the Plan. The CEAB is adjusting the 2008 Procurement Planning process to meet the following important objectives:

1. Develop a 2008 Procurement Plan that contains key recommendations for resource procurement actions that need to move forward expeditiously in 2008.
2. Address the key issues identified in the review process that require attention in 2008, including energy efficiency and demand management, transmission requirements, aging Connecticut generation, and compliance with environmental regulations.
3. Engage the key stakeholders[128] in the process to collaborate in the execution of this work and to provide important input.
4. Provide the DPUC with a well considered and comprehensive 2008 Procurement Plan on a schedule that affords the DPUC opportunity to conduct a 120 day review.
5. In the course of developing the 2008 Plan, create a process and planning template to guide and expedite future planning in order to facilitate substantially improved plans in future years.

To accomplish these objectives, the CEAB is adopting a work plan designed to complete a modified Procurement Plan for submission to the DPUC on August 1, 2008.

[128] The key stakeholders include, but are not necessarily limited to, ISO New England, the owners of generation assets in Connecticut, the Energy Conservation Management Board, the Connecticut Clean Energy Fund, the Department of Environmental Protection, and Connecticut Municipal Electric Energy Cooperative.

III. Scope of the 2008 Procurement Plan Process

The 2008 Procurement Plan Process scope of work includes the following components:

1. **Information Gathering**: The process will be used to obtain additional information in several key areas where such information is available or can be readily assembled. The public comment process has made clear that additional information in areas such as renewable energy projects, existing generation assets, environmental requirements, transmission needs, and forward capacity market results is necessary. Attachment 1 identifies a preliminary list of topics to consider.
2. **Analysis**: The utilities modeling of the Connecticut system can be used to address additional issues, particularly in the areas of emissions compliance testing and generation retirement scenarios.
3. **Procurement Planning**: The information, analysis, and public input will be assessed to form an Action Plan for resource procurement that will be recommended to the DPUC for consideration. In addition, the 2008 process will identify overall process improvement in the procurement plan development which will continue with subsequent annual planning cycles.
4. **Scope of Future Study**: In this 2008 process, areas requiring additional research or analysis will undoubtedly be identified that cannot be completed in this planning cycle. These areas will be included in an action plan for the 2009 Planning Process.

IV. Schedule for the Process

As noted in Section II, August 1, 2008 is the planned date for submission of the modified Plan to the DPUC. This date will allow time to conduct targeted additional analysis, gather other readily available information, and develop a procurement plan recommendation on a schedule that preserves the opportunity for the DPUC to conduct a 120 day review in 2008. This schedule also allows the Distribution Utilities to file a 2009 Procurement Plan on January 1, 2009, as originally contemplated in Section 51.

Attachment 2 provides a Gant Chart depicting the CEAB's anticipated timeline for this 2008 Procurement Plan process and the associated DPUC and Company activities through completion of the 2009 Procurement Plan Review. Specific elements of the DPUC and Company actions are discussed further in later sections of this report.

V. Structure of the Collaboration and Stakeholder Process

The Plan submitted to the DPUC on August 1, will be modified and approved by the CEAB. However, the CEAB and the Distribution Utilities both have responsibilities under Section 51 for the 2008 Plan and for planning in future years. Therefore, the CEAB will be seeking to develop a modified plan in primary collaboration with the Distribution Utilities and their consultant, The Brattle Group.

In addition to the collaboration with the Distribution Utilities, it is clear that there are many other key stakeholders in this process who are able to: a) provide valuable input to this effort; and b) have a direct role in the implementation of the Plan. Therefore, the CEAB is undertaking a process to engage these stakeholders in the process as well. Participation of these stakeholders can facilitate information gathering and the development of analysis and recommendations.

The emphasis on key stakeholders here is not intended to exclude any interested parties from participating in this process. However, the August 1, 2008 Plan will be subject to a review at the DPUC, providing a forum for all stakeholders and interested parties to provide comment and further input to the Plan. Again, the objective of this process is to have the CEAB and the Distribution Utilities engage constructively with key stakeholders to assure that the August 1, 2008 Plan reflects the best available information, and reasonably considers the implications for those that would be directly involved in its implementation. We expect this will involve a number of working sessions and progress reports delivered at CEAB meetings throughout the process.

There will also be at least three (3) stakeholder workshops, as follows:

1. **Planning Inputs and Analysis Workshop -** this forum will be structured to discuss information gathering and analysis efforts for the planning process. This will be structured by topic (e.g., renewable supplies, environmental requirements, generation assets) to identify the information available and action plans to collect information in a useful format for planning purposes. This will be scheduled for completion by mid-March.

2. **Planning Inputs and Analysis Workshop II** – this will be a follow-up to the first forum, with the objective of reporting on information assembled and discussion of that input and its potential use in the Plan. This will be scheduled for completion by mid-May.

3. **Procurement Planning Workshop** – this will be a discussion on options for needed actions to implement resource procurement identified for inclusion in the Plan. This will be scheduled for completion by mid-June.

In addition to these workshops, we anticipate stakeholders will develop inputs for use in the planning process and that informal dialogue will be ongoing. As the process develops, the number and structure of these workshops may be modified to meet the objectives for the August 1, 2008 Plan.

VI. The DPUC Review Process and DPUC Proceedings

This planning process is required to provide a more fully developed Procurement Plan that conforms to the statute and merits the CEAB's approval for consideration by the DPUC. The August 1, 2008 timeframe will afford the DPUC an adequate time to conduct a 120 day uncontested proceeding to consider the Plan and comments that it receives, and issue its final decision on the Plan by December 1, 2008.

The 2008 Planning Process will incidentally enable consideration of the results of relevant and pending DPUC proceedings to inform the Plan, as appropriate, including:

1. **Docket No. 07-01-61: DPUC Examination Of Electric Distribution Company Contracts For Renewable Energy Certificates**: This proceeding is underway and is scheduled for a final decision by April 30, 2008.
2. **Docket No. 07-06-58; Docket 06-01-08PH01: DPUC Report To Connecticut General Assembly On Standard Service Procurement**: This proceeding is ongoing. While no date has been established for the issuance of a report, comments have been filed and the hearing has been closed.
3. **Docket No. 08-01-01 - DPUC Review of Peaking Generation Projects**: This proceeding is underway. Seven entities submitted qualification packages by February 1, 2008. Peaking generation proposals are due by March 1, 2008. A DPUC final decision on these proposals is due by July 1, 2008.

VII. The ECMB Achievable Potential Study

The ECMB is beginning a project to prepare an achievable potential study for energy efficiency and demand management. The study is currently scheduled to begin in March once the consultants are retained. The energy efficiency phase of this work is slated for a final report on October 3, 2008. The demand response phase of this work is slated for a final report on November 28, 2008.

The schedule for this work extends beyond the August 1, 2008 deadline for the modified Pan. The 2008 planning process will monitor ECMB's progress. However, due to the proposed project schedule the results of this work will not be considered in the 2008 Plan.

VIII. The 2009 Procurement Plan

This modified 2008 Planning Process is designed to establish a strong foundation for the 2009 planning cycle. Section 51 establishes an annual planning cycle beginning with the Distribution Utilities' filing on January 1st of each year.

The August 1, 2008 Plan will include an action plan for work beyond the scope of this 2008 effort, but achievable for the 2009 Plan. It is reasonable to expect the Distribution Utilities to proceed with that work in parallel with the DPUC review of the August 1, 2008 Plan.

Before filing the January 1, 2009 Plan, the Distribution Utilities will be able to consider:

1. The action items recommended in the August 1, 2008 Plan;
2. The DPUC's perspective, recommendations and final decision in its review of the August 1, 2008 Plan; and,
3. The ECMB achievable potential study results.

The January 1, 2009 Plan will be well informed by this 2008 process, which should provide a sound, comprehensive basis to start the 2009 process and establish the blueprint for annual updates thereafter. This 2008 process is expected to be a developmental process that should not need to be replicated in 2009 and beyond. The analytical and collaborative foundation set in this 2008 process should provide the effective and timely process originally contemplated in Section 51.

Attachment 1

Potential Focus Areas for Added Information

Renewables and CHP

- Develop a revised view of Renewable Supply
- Meld Companies Assessment with CCEF/Grace Info
- Capture stakeholder information on CHP

Existing Generation Issues

- Develop a revised assessment of retirement/go forward issues
- Define assumptions or scenarios with Generation Owners

Environmental Emissions Performance Issues

- Characterize the key emissions compliance challenges over the next 10 years

Transmission

- NEEWS – review of needs assessment assumptions vs current
- SWCT 2012-2018 Needs Assessment
  - Study Group results targeted for March 2008 completion
- Eastern CT 2012-2018 Needs Assessment
  - Study Group results targeted for March 2008 completion

APPENDIX E

Status Report: Conclusion of Stakeholder Input Process

2008 Comprehensive Plan for the Procurement of Energy Resources

Prepared by:
The Connecticut Energy Advisory Board

CEAB
Connecticut Energy Advisory Board

Approved August 1, 2008

La Capra Associates

Procurement Plan:
Status Report -
Conclusion of Stakeholder Input Process

Prepared by: John Athas
Dan Peaco
Heather Hunt

Prepared for: Connecticut Energy Advisory Board

La Capra Associates

Procurement Plan Status Report – Today's Discussion

I. **Overview of Utility Plan and CEAB Response**

II. **Report on Stakeholder Workshops**
   - **Process and Issues**

III. **CEAB and Utility Collaboration on Additional Analysis**

IV. **Remaining Activities and Timing**

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I. *Overview of Filed Utility Plan and CEAB Response*

- Legislatively Prescribed Procurement Planning Process
- January 2008 Plan filed Jointly by CL&P and UI
- CEAB Initial Review – February, 2008
- Public Comment/Hearing on Utilities' Plan
- CEAB Process for Modifying Utilities' Plan
  - Stakeholder Input Workshops
  - Collaborative Analysis CEAB consultants and utilities

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CEAB Process for 2008 Plan

- **Objectives**
  1. A 2008 Plan with recommendations for procurement actions
  2. Address Key Issues Identified in the review process
  3. CEAB-Utilities collaboration with key stakeholder input
  4. Provide the DPUC a well-considered 2008 Plan for 120 day review
  5. Develop the Planning Process to expedite 2009 and future planning cycles

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Stakeholder Input Process – Focus on Key Areas

- Demand Management
  - Focus on funding mechanism for aggressive program approaches
- Renewable Energy
  - Examine CCEF outlook for meeting RPS requirements
- Environmental Compliance
  - Address ground level ozone emissions regulations
- Connecticut Generation
  - Examine ability to rely on continued operation of older steam-based generation throughout the next 10+ years
- Transmission
  - Integrate transmission options and studies into analysis

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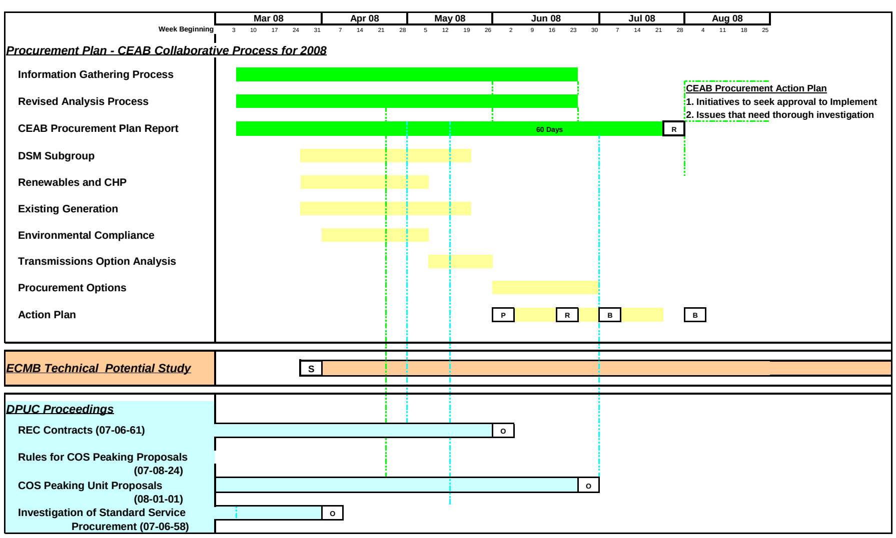
Stakeholder Input and Collaborative Analytical Process



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Procurement Plan Status Report – Today's Discussion

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Collaboration Process in 2008 Modified Plan

- **CEAB and Utilities Collaboration**
  - Goal: Address Key Issues Jointly to the extent possible
  - Ultimately, August 1, 2008 Plan will be a CEAB Plan
- **Key Stakeholder Input**
  - Several stakeholders offered to assist in comments
  - Overview of CEAB process presented to Stakeholders March 13th
  - Many have key information and necessary input
  - Workshops held with targeted stakeholders that have important information to capture for consideration in the Plan

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Demand Management – Recommendation to Move to DSM Focus

Information and Direction

- **Reviewed DSM analysis basis for scope, cost and practical potential** of the expansion of Energy Efficiency and Price Responsive Demand
  - Cost effectiveness process
  - Capability to ramp up programs
  - Funding Sources for DSM expansion
- **ECMB asked CEAB to formally support its request to the DPUC** to immediately bring energy efficiency funding to the levels established as economic in the utilities projects and identified
- ECMB expects **high consumer demand levels** for programs is an indicator of the capability to aggressively scale up programs.
- **DSM Focus is a legitimate resource** case pending outcome of DSM potential study for energy efficiency and demand response
- **DSM Focus levels of savings should be a fundamental planning assumption** for evaluation of generation and transmission needs and emissions implications

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Demand Management – Recommendation to Move to DSM Focus

Qualifiers

- The DPUC has not approved the a long range funding plan
- Revised assessments of programs will occur annually in ECMB budget approval process
- A more detailed look at the potential will be available in the Fall of 2008
- Levels of programs both energy efficiency and demand response is unprecedented

Stakeholders

- Utilities, ECMB, Environment Northeast, AARP, First Light Power

Workshops

- Workshops held April 11 and May 2

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Renewable Energy

Information and Direction

- Renewable project development that includes **long term contracts should result in REC prices closer to a cost basis** than to ACP
- **Renewables should be modeled in scenarios with associated transmission projects**
- Each scenario will incorporate state by state results of **supply curve analysis**
- **REC pricing will be phased in to be based on primarily long term contract prices** for RECs substantially below ACP
- Result: in **3 of the 4 scenarios RPS requirements should be met**

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Renewable Energy

Qualifiers

- Long Term REC contracting is not prevailing policy in region
- Projected renewable capacity used in the subsequent analysis will be based on resource potential, not specific projects under development
- The Plan should discuss dynamics of long term contracting, project development and REC pricing

Stakeholders

- Utilities, CCEF, Environment Northeast, AARP

Workshops

- Workshops held April 2, 17 and May 5
- Other calls with CCEF consultants

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Environmental Compliance

Information and Direction

- **Initiated dialogue between DEP, utilities and Connecticut Generation owners**
- **Established scenario assumptions** for individual Electric Generation Unit (EGU) for each scenario
- Establishing planning levels for Statewide compliance of individual pollutants, particularly NOX and CO2
- Apply **multiple scenarios/cases for individual EGU emission rate levels** for NOx, Sulfur, CO2 and HG to modeling effort of utilities
- Apply multiple scenarios/cases for statewide targets/caps of individual pollutants
- **Metrics to be produced to demonstrate plan impacts on High Electric Demand Days (HEDD)** emissions to enable future working group efforts be captured in procurement planning

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Environmental Compliance

Qualifiers

- Supplemental analysis will build-in DEP air quality regulation changes that are contemplated but not yet adopted
- Generator response to evolving regulations could vary from analytical results that the collaborative with utilities will produce

Stakeholders

- Utilities, CCEF, Environment Northeast, AARP

Workshops

- Workshops held April 14 and May 5
- Numerous discussions with DEP staff

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Connecticut Generation

Information and Direction

- **Initiated dialogue between DEP, utilities and Connecticut Generation owners on continued operation costs**
- **Attempted to secure support of generators to provide:**
  1. A primer on the way a generating company looks at continued operation of older generation.
  2. Cost estimates for these relevant categories by generating unit technology.
  3. Individual owners' sponsored best available public information to be used with specific units in economic analysis.
  4. Support in applying the correct 'potential' retrofit projects, i.e., emissions reduction technologies, for the each unit.
- **NRG provided technical expertise in identifying likely environmental compliance retrofit projects**
- Generation companies via NEPGA maintain the **appropriateness of FERC level revenue requirement costs as the proper GFC for determining continued operation**

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Connecticut Generation

Qualifiers

- **No consensus** on how to estimate economic obsolescence
- CEAB analysis will assume utility GFC and environmental compliance project costs in determining likely retirement cases
- Generator response to evolving regulations could vary from analytical results the collaborative with utilities will produce.

Stakeholders

- Utilities, DEP, Environment Northeast, AARP, NRG, PSEG, Competitive Power Ventures, NEPGA, First Light Power

Workshops

- Workshops held April 2, 17 and May 5
- Numerous discussions with NRG, First Light and NEPGA

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Transmission Considerations

Information and Direction

- Meetings with ISO and stakeholders (plus PAC meetings) established views on:
  - Needs Assessment & Options Analysis Report
  - 2010 FCM Delisting Process Reliability Assessment
  - Additional Connecticut Areas of Concern (from Nov 07 PAC) ISO-NE
  - LFRM & Daily Second Contingency Dispatch Requirements
  - ISO studies on Transmission requirements to support renewable generation build out
- Plan to run indicative analysis comparing in state generation v. substantial transmission investment

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Transmission Considerations

Qualifiers

- ISO-NE analysis on transmission to support renewables not yet complete
- Analysis must capture some transmission projects in Maine
- Connecticut should not be a capacity zone with NEEWS
- Phase II of the current CT Transmission project and the CT procurement dramatically reduce requirements for operating reserves

Stakeholders

- Utilities, NRG, PSEG, Competitive Power Ventures, NEPGA, First Light Power, ISO-NE

Workshops

- Workshop held May 14
- Additional meeting to be scheduled with Northeast Utilities

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Procurement Plan Status Report – Today's Discussion

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III Collaborative Analytical Effort with the Utilities

- **Many questions need to be addressed for complete IRP and Procurement analysis**
- **With utilities, we are prioritizing the analysis to be finalized in next few weeks**
- **Future analytical agenda to be established**

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THEMES TO REPORT ON IN CEAB REPORT

1. **DSM Focus**
    1. Economics
    2. Potential
    3. Risks
2. **Renewable Energy**
    1. Economics Potential
    2. Current Project Potential
    3. Renewable Resource developable potential vs. RPS
    4. Need for and benefits of long term REC contracting
    5. Results of Supply curve build out approach
3. **Outlook for existing Connecticut Generation**
    1. Economics of Continued Operation in FCM Market
    2. Impact of tightening emissions on Continued Operations
    3. Retirement potential
        * LSR impact ,LFRM impact, Emissions Profile Impact, Transmission build requirements

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THEMES TO REPORT ON IN CEAB REPORT (cont'd)

4. **Comparison of Connecticut to Outside Connecticut generation builds**
    - LMP suppression
    - Transmission Build requirements
    - Capacity Zone Risk
5. **Indicative analysis of Non-Transmission Alternatives to NEEWS**
6. **The Value of Hedging through**
    1. Standard Service long-term purchases
    2. Contracting for Renewables Energy, Capacity and RECs
    3. In State ICAP
    4. New OPCAP
    5. Energy Block Purchasing Long-term
    6. COS Generation
        1. Existing Capacity
        2. New Capacity

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Analysis Prioritization Process

- **Establish a new analytical baseline**
  - **Current Trends Scenario**
  - **Renewable Energy Build out that meets RPS**
  - **DSM Focus**
  - **Emission rate limits set at lower / next step DEP levels**
  - **Provide additional metrics for HEDD demand day and summer NOx measurements**
- **Review Metrics**
  - **Establish a few limited alternative cases**
    - Transmission changes
    - Nuclear injection
    - .,…

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Procurement Plan Status Report – Today's Discussion

I. Overview of Filed Utility Plan and CEAB Response

II. Report on Stakeholder Workshops

- *Process and Issues*

III. CEAB and Utility Collaboration on Additional Analysis

IV. Remaining Activities and Timing

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Remaining Milestones – approximate dates

- **June 26th -** ***Preview of results to subcommittee***
  - ***Scenario Metric Analysis***
  - ***Resource Considerations and Analyses***
  - ***Procurement Options***
  - ***Costs, Benefits and Risks***
  - ***Recommendations***
  - ***Proposed Report outline***
- **June 30th-** ***Preview for July 11th CEAB Meeting***
  - ***Revised*** **PowerPoint Presentation on Results and recommendations**
- **July 3rd material distribution for June CEAB Meeting**
  - ***Present PowerPoint on recommendations and results***
- **July 11th CEAB Meeting**
  - ***Present Results***
  - ***Vote On Recommendations***
- **July 21st Circulate Draft Report for Comment**
- **July 25th Send Final Report to the Board in their Monthly Package**
- **August 1st CEAB Meeting**
  - ***Vote on Plan***

Supporting Material – Not to be Presented unless needed within the Discussion

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I. *Overview of Filed Utility Plan and CEAB Response*

- Legislation and the Prescribed Procurement Planning Process
- The January 2008 Plan filed Jointly by CL&P and United Illuminating
- CEAB Initial Review – February, 2008
- Public Comments on the Utilities' Procurement Plan
- Revised CEAB Process for Modifying the Utilities' Plan
    - Stakeholder Input Workshops
    - Collaborative Analysis CEAB consultants and the utilities

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Procurement Planning Process Statutory Timeline

- **Utilities jointly develop a Connecticut Procurement Plan**
- **Utilities present the plan for CEAB review on January 1, 2008**
    - **Utilities and their consultant Brattle Group make a presentation to the CEAB on January 4, 2008**
- **CEAB has 120 days for 2008 cycle to review and analyze the Utilities' plan.**
    - **Future years the CEAB will have 60 days**
- **CEAB approves or modifies and approves the plan then submits the plan to the DPUC by May 1, 2008**
- **DPUC conducts a review of the filed plan, 120 days**
    - **Future years the DPUC will have 60 days**

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The January 2008 Plan filed Jointly by CL&P and UI

Findings

1. Regional resource adequacy needs are satisfied for the next several years.
2. Connecticut's local resource adequacy needs are satisfied for the foreseeable future.
3. Market prices will continue to be high and volatile.
4. Natural gas dependence will persist.
5. External, uncontrollable factors are the primary drivers of customer costs
6. Renewable Portfolio Standards are unlikely to be fully met with renewable generation.
7. Nuclear and DSM mitigate CO2emissions more effectively than other resource solutions.
8. Increased DSM could reduce customer Costs, CO2emissions, and gas usage.
9. Non-gas base load generation would reduce dependence on natural gas.
10. "Market Regime" vs. "Cost-of-Service" affects rate stability, and may have future customer cost implications.

Recommendations

1. Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.
2. 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.
3. 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.
4. Consider potential ways to mitigate the exposure of Connecticut consumers to the price and availability of natural gas (though it will not be possible to eliminate gas dependence).

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The January 2008 Plan filed Jointly by CL&P and UI

- **Study Components**
  1. Quantify the need for additional resources across a range of scenarios.
  2. Identify potential resource solutions (supply & demand-side) to meet needs.
  3. Evaluate the performance of resource solutions.
  4. Recommend resource strategies.

  Regional Scope & Time Horizon
  - ISO-New England electric market simulation
  - Modeled years 2011, 2013, 2018 and 2030
- ***Methodology***
  - Four Scenarios
  - Five future generation addition cases
    - ***Conventional, DSM Focus, Coal and Nuclear***
- ***Metrics***
  - Customer Cost, Market Price, Gas Dependence, Emissions….

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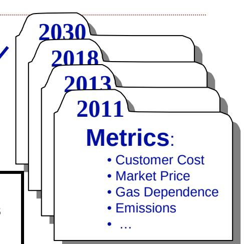
Procurement Plan Scenario Summary

Scenario Name	Fuel Prices	Load	Cost / Siting	CO_2 Price
“Current Trends”	Moderate	Moderate	Nominal (high)	Moderate (high)
“Strict Climate”	Slightly High	Slightly Low	Nominal (high)	High
“High Fuel/Growth”	Very High	High	Higher	Somewhat Higher
“Low Stress”	Low	Very High	Moderate	Moderate (high)

Study Architecture



4 Scenarios

4 Resource Solutions

	Current Trends	Strict Climate	High Fuel/ Growth	Low Stress
Conventional Gas	Metrics	Metrics	Metrics	Metrics
DSM-Focus	Metrics	Metrics	Metrics	Metrics
Nuclear	Metrics	Metrics	Metrics	Metrics
Coal	Metrics	Metrics	Metrics	Metrics

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Identify Candidate Resource Solutions

Resource Solution	Planned DSM *	Candidate Resources	Additional Gas
"Conventional Gas"	Aggressive	**Gas-fired CCs and CTs** Economic mix of technologies	As needed to fill rest of gap
"DSM-Focus"	Aggressive	**Additional DSM**** by 2011: +160 MW, 370 GWh by 2013: +320 MW, 1000 GWh by 2018: +603 MW, 2600 GWh	As needed to fill rest of gap
"Nuclear"	Aggressive	**1 Nuclear Unit in 2018** (1200 MW)	As needed to fill rest of gap
"Coal"	Aggressive	**1 Coal Unit in 2018** (1200 MW)	As needed to fill rest of gap

***** DSM effectiveness (on reducing peak load MW & energy GWh) depends on scenario.
****** Values shown are for Current Trends scenario.

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CEAB Initial Review – Summary Scorecard

Plan Compliance with the Requirements of PA 07-242 Section 51(b): January 1, 2008 Plan Contents

Section 51, Part (b): On or before January 1, 2008, the companies shall submit to the Connecticut Energy Advisory Board an assessment of:

Requirement	Degree of Compliance
1) the energy and capacity requirements of customers for the next 3, 5 and 10 years	FULL
2) the manner of how best to eliminate growth in electric demand	PARTIAL
3) how best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods	PARTIAL
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	LOW
5) energy security and economic risks associated with potential energy resources	PARTIAL
6) the estimated lifetime cost and availability of potential energy resources	PARTIAL

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CEAB Initial Review – Summary Scorecard

Plan Compliance with the Requirements of PA 07-242 Section 51(b): January 1, 2008 Plan Contents

Section 51, Part (c): 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 basis with non demand-side resources. The procurement plan shall specify:

Requirement	Degree of Compliance
1) the total amount of energy and capacity resources needed to meet the requirements of all customers,	FULL
2) the extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs,	FULL
3) needs for generating capacity and transmission and distribution improvements,	PARTIAL
4) how the development of such resources will reduce and stabilize the costs of electricity to consumers, and	PARTIAL
5) the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources.	LOW

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CEAB Initial Review – Summary Scorecard

Plan Compliance with the Requirements of PA 07-242 Section 51(b): January 1, 2008 Plan Contents

Section 51, Part (d): The procurement plan shall consider

Requirement	Degree of Compliance
1) Approaches to maximizing the impact of demand-side measures;	FULL
2) the extent to which generation needs can be met by renewable and combined heat and power facilities;	PARTIAL
3) the optimization of the use of generation sites and generation portfolio existing within the state;	LOW
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;	PARTIAL
5) reliability, peak load and energy forecasts, system contingencies and existing resource availabilities;	PARTIAL
6) import limitations and the appropriate reliance on such imports; and	FULL
7) the impact of the procurement plan on the costs of electric customers.	PARTIAL

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CEAB Initial Review – February 1, 2008 Board Discussion

- **Concern expressed about the lack of consideration given to the following:**
  - **Existing Connecticut generation unit retirements**
  - **Environmental compliance needs**
  - **Transmission Project and alternatives**
- **There was consensus of the board that the document is highly inadequate and does not meet the mandates of the legislation.**
- **There was consensus that a final decision on a course of action should be delayed until public comment was in and the February 11th public hearing complete to see if they provided any insights relevant to making a decision on a course of action.**

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Synopsis of Public Comment

- **Written Comments**
  - Twenty sets of written comments from organizations
  - Over forty emails from individuals
- **Comments at Public Hearing**
  - Over a dozen speakers from commenting organizations
  - Brattle Group, the Companies' consultant
  - Transcripts prepared

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Recommendation 1: Maximize DSM

- **Summary of Comments**
  - ECMB and many others strongly support
  - Most individual emails addressed this point
  - Several comments expressing concerns on feasibility, cost, and reliability
- **Observations:**
  - Recommendation is consistent with Sect 51(c) emphasis
  - The Plan uses best available information to assess this goal
  - Further work needed on implementation and integration

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Recommendation 2: Explore Long Term Contracts

- **Summary of Comments**
  - Several cautionary comments on L-T contracts
  - Several recommendations for further inquiry
  - Comments on the value for Renewable projects
- **Observations:**
  - The Plan is not offered as a Procurement Plan
  - This area warrants attention; clearly requires further work

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Recommendation 3: Evaluate RPS Structure

- **Summary of Comments**
  - Several comments differed with the Plan's renewables analysis
  - Several noted the lack of a CT potential assessment
  - CCEF analysis points to several omissions
- **Observations:**
  - The Plan would benefit from added information
  - More investigation of compliance with current RPS is useful
  - This area warrants attention; clearly requires further work

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Recommendation 4: NG Exposure Mitigation

- **Summary of Comments**
  - Some note that DSM and renewables would meet this need
  - AG proposes a refund mechanism
  - Some note that permitting and siting improvements are key
- **Observations:**
  - The issue is complex and interconnected with other issues
  - This area warrants attention; clearly requires further work

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Other Key Issues Addressed in the Status Report

- **Overall Statutory Compliance**
- **Transmission Analysis**
- **Assumptions Concerning Generation Retirements**
- **Availability and Advancements in Technology**
- **Return to Cost of Service**

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Process Proposal for 2008 and 2009 Plans

- **Objectives**
  1. A 2008 Plan containing recommendations for procurement actions needed in 2008
  2. Address the Key Issues ID'ed in the review process
  3. CEAB-Utilities collaboration with key stakeholder input
  4. Provide the DPUC a well-considered Plan for 120 day review in 2008
  5. Develop the Planning Process to expedite 2009 and future cycles of the process

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Process Proposal – Collaboration Process

- **CEAB and Utilities Collaboration**
  - Goal to address Key Issues Jointly, to the extent possible
  - Ultimately, August 1, 2008 Plan will be a CEAB Plan
- **Key Stakeholder Input**
  - Several stakeholders have offered to assist through comments
  - Many of these have key information and input needed
  - Workshops targeted to stakeholders that have important information will be conducted to assure this input is captured for consideration in the Plan

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Procurement Plan Status Report – Today's Discussion

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II. Report on Stakeholder Workshops

- **Process and Issues**

III. CEAB and Utility Collaboration on Additional Analysis

IV. Remaining Activities and Timing

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Stakeholder Input Process - Scope

Information Gathering: focus on key areas:

- **Demand Management** – review Utilities recommendation to dramatically increase Energy Efficiency and Price Responsive Demand funding
- **Renewable Energy** – reconcile the utility perspective with that of the CCEF regarding the outlook for meeting RPS requirements.
- **Environmental Compliance** – integrate into the analysis the impacts of the continued reliance on older high emissions generating capacity
- **Connecticut Generation** – work with utilities and the Connecticut generation owners to incorporate a more realistic viewpoint of the ability to rely on the continued operation of older steam-based generation throughout the next 10 plus years.
- **Transmission** – develop additional analysis showing the impact transmission projects will have on economics, installed capacity, operable capacity, operating reserve, and statewide emissions.
- **Procurement Options** – analyze the most beneficial 'procurement' actions to meet the multiple objectives of minimizing ratepayer costs, emissions compliance and reliability.

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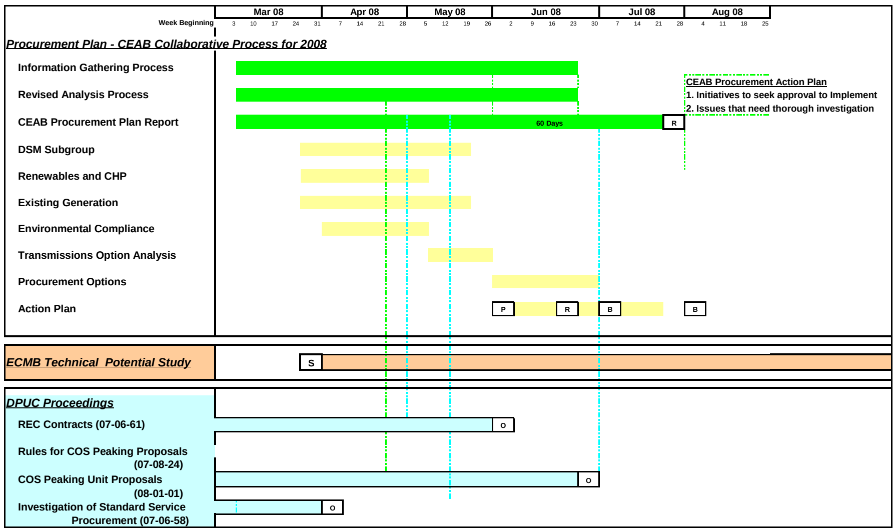
Stakeholder Input and Collaborative Analytical Process



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Demand Management

1. **Issues**
   - **The utilities analysis of the DSM was a comprehensive analysis working collaboratively with the Energy Conservation Management Board (ECMB) showed large additional potential of the DSM Focus 'resource' level**
   - **Updated both energy efficiency and demand response program effects**
   - **Adjustments were made to account for vintage of DSM economic potential study which is being updated this year and should be available by the Fall 2008**
   - **Concern expressed on scaling programs versus economic analysis**
   - **Concerns on the deliverability**
   - **Concerns on additional funding source requirements**
2. **Stakeholders**
   - **Utilities, ECMB, Environment Northeast, AARP, First Light Power**
3. **Workshops**
   - **Workshops held April 11 and May 2**

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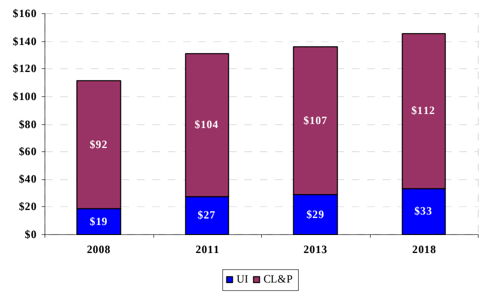
Utilities' Analysis - DSM Funding Level Assumptions show aggressive growth

- **Table D.8: Reference Level DSM Annual Budgets (Nominal $ Million)**

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	$17	$17	$19	$21	$23	$24	$25	$25	$26	$27	$28	$29
UI DR	$1	$2	$4	$4	$4	$4	$5	$5	$5	$5	$5	$5
CL&P EE	$68	$68	$71	$78	$81	$82	$83	$85	$86	$87	$88	$89
CL&P DR	$25	$24	$23	$23	$23	$23	$23	$23	$23	$23	$23	$23
Total (UI + CL&P)	$111	$112	$118	$128	$131	$134	$136	$138	$140	$142	$144	$146

- **Figure D.5: Reference Level DSM Annual Budgets (Nominal $ Million)**



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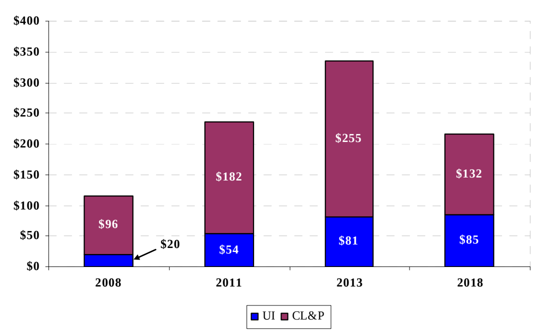
Utilities' Analysis - The Higher DSM FOCUS Funding Levels and Impacts are Unprecedented

- **Table D.9: DSM-Focus Level DSM Annual Budgets (Nominal $ Million)**

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI Total	$18	$20	$26	$38	$54	$70	$81	$81	$82	$83	$84	$85
CL&P Total	$94	$96	$109	$140	$182	$226	$255	$270	$256	$206	$153	$132
Total (UI + CL&P)	$112	$116	$135	$177	$236	$296	$336	$352	$338	$289	$236	$216

- **Figure D.6: DSM-Focus Level DSM Annual Budgets (Nominal $ Million**



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Demand Management – Recommendation to move to DSM Focus

Information and Direction

- Reviewed DSM analysis basis for scope, cost and practical potential of the expansion of Energy Efficiency and Price Responsive Demand
  - Cost effectiveness process
  - Capability to ramp up programs
  - Funding Sources for DSM expansions
- ECMB has request CEAB to formally support its proposal before the DPUC to immediately bring funding levels for energy efficiency to the levels established as economic in the utilities projects and identified
- ECMB expects high consumer demand levels for their programs is an indicator of the capability to aggressively scale up programs.
- DSM Focus is a legitimate resource case pending the outcome of the DSM potential study for both energy efficiency and demand response
- DSM Focus levels of savings should be a fundamental planning assumption for evaluation of generation and transmission needs and emissions implications

Qualifiers

- The DPUC has not approved the a long range funding plan
- Revised assessments of programs will occur annually for the ECMB budget approval process.
- Levels of programs both energy efficiency and demand response is unprecedented

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Renewable Energy – REC Shortfall

1. **Issues**
   - **The utilities analysis of the renewable energy project potential that lead to their concern on the likely renewable energy development shortfall as compared with the RPS requirements.**
     - Analysis based observations on current renewable project queue
     - Supported the current price level for Renewable Energy Credits (RECs) which is close to Alternative Compliance Payment (ACP) of $55/mWh
     - Overall annual customer costs may rise to $200 million by 2011, $300+ million in 2018 ($2008)
     - Some RECs at/near price cap level
     - Significant portion in ACP –large revenue stream
     - This outlook deserves additional study at the regional level to evaluate current policy
     - Transmission costs and concerns could dampen project development
   - **CCEF presented information on an strong development pipeline for renewables**
2. **Stakeholders**
   - **Utilities, CCEF, Environment Northeast, AARP**
3. **Workshops**
   - **Workshops held April 2, 17 and May 5**
   - **Other calls with CCEF consultants**

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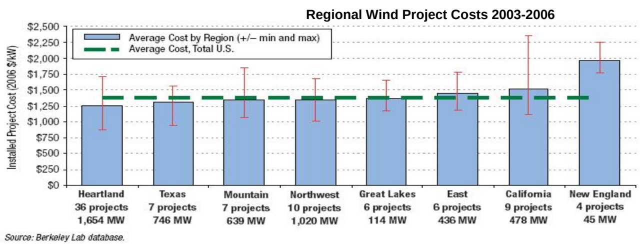
Utilities Analysis - Renewable Portfolio Standards are Unlikely to be Fully Met with Renewable Generation

- **Connecticut Renewable Portfolio Standard (RPS):**
  - **Escalating requirements similar to other New England states**
  - **Can use New England renewable energy credits (RECs)**
  - **Alternative payments (for REC shortfall) of $55/MWh, <u>not</u> adjusted for inflation as other New England States**
- **Renewable Costs**
  - **Connecticut renewables limited and/or expensive compared to New England renewables**
  - **New England targets may not be met fully with renewables, due to costs and constraints**



Source: Berkeley Lab database.

New England:

$2000/kW

45 MW Developed

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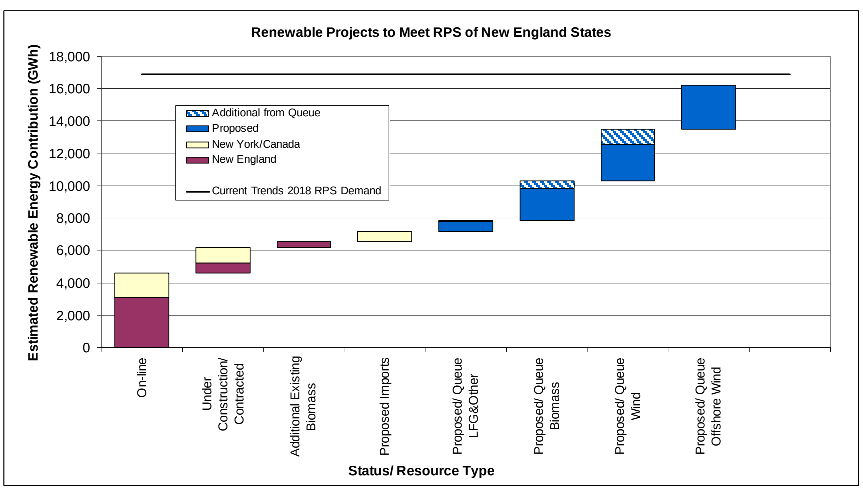
Renewable Energy Generation Projects under Development



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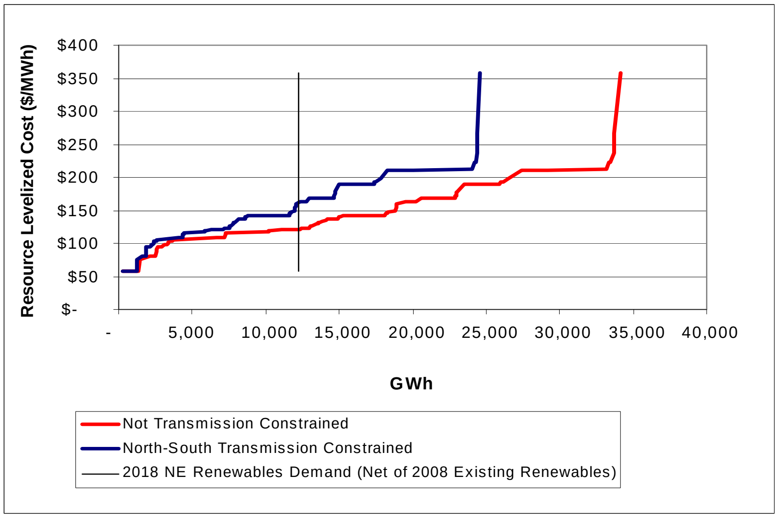
Regional Renewable Energy Resource Potential – 2018



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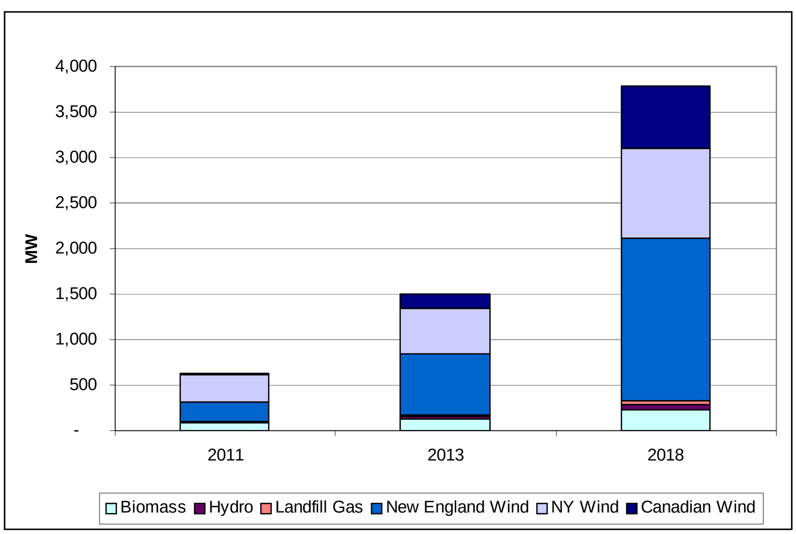
Preliminary Renewable Energy Resources to meet RPS



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Renewable Energy

Information and Direction

- Renewable energy generation project development that includes long term contracts should result in REC prices closer to a cost basis rather than ACP
- The renewables should be modeled within the scenarios with the associated transmission projects.
- Each scenario will incorporate the state by state results of the supply curve analysis.
- REC pricing will be phased in to be based on primarily long term contract prices for RECs substantially below Alternative Compliance Payments
- The result is that in 3 of the 4 scenarios RPS requirements should be met

Qualifiers

- Long Term REC contracting is not the prevailing policy in the region
- Projected renewable capacity used in the subsequent analysis will be based on resource potential rather than specific projects under development
- The Plan should discuss the dynamics of long term contracting and project development and REC pricing

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Environmental Compliance

1. **Issues**
   - The utilities analysis did not account for evolving regulations for reducing allowed generation unit emission rates
     - Status quo on regulations assumed
     - NOx, SO2 and CO2 allowance costs were included in modeling
   - DEP regulations trying to balance cost effective NOx reductions which may be accomplished with alternative resources supplementing emission rate reductions
   - Evolving emission control technology requirements could impact the continued operation of existing CT generation
2. **Stakeholders**
   - Utilities, DEP, Environment Northeast, AARP, First Light Power, NRG
3. **Workshops**
   - Workshops held April 14 and May 5
   - Numerous discussions with DEP staff

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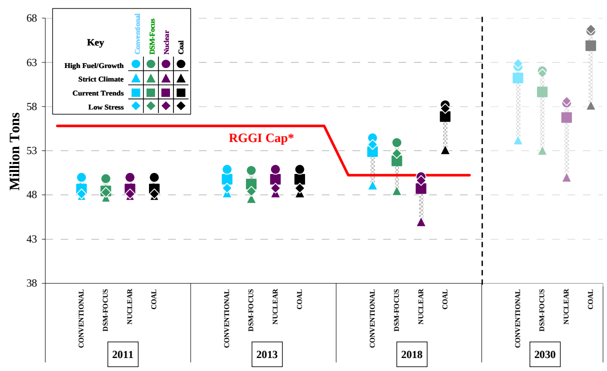
Utilities' Analysis Focused on CO2 - Nuclear and DSM Mitigate CO_2 Emissions More Effectively than Other Resource Solutions

CO_2 Emissions in ISO-NE

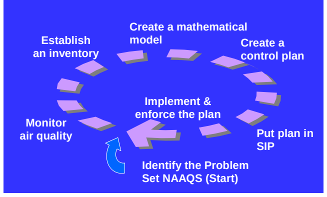


*Emissions and RGGI cap shown here reflect the 6 member states of ISO-NE only. A surplus or deficiency does not indicate whole RGGI-region status.

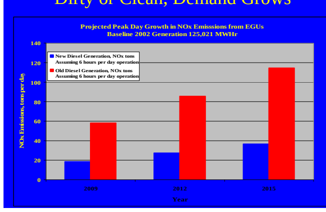
- CO_2 emissions are expected to increase as load grows.
- Nuclear displaces significant fossil CO_2.
- Coal raises emissions substantially above New England's share of the RGGI cap.
- Increased DSM (that includes energy efficiency) also reduces CO_2 emissions.

Extensive Utilities', CEAB discussion with DEP and Generators

Air Quality Management Plan



Dirty or Clean, Demand Grows



OTC HEDD MOU Commitments

State	NOx (tons per day)	% Reduction from HEDD Units
CT	11.7	25
DE	7.3	20
MD	23.5	32
NJ	19.8	28
NY	50.8	37
PA	21.8	32
Total	134.9	

CT CO_2 Caps – Proposed Rule

- 2009-2014 10,695,036 tons CO2
- 2015 10,427,660 tons CO2
- 2016 10,160,284 tons CO2
- 2017 9,892,908 tons CO2
- 2018 9,625,532 tons CO2

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Enhancing the Scenario Modeling of Future Regulations

	Boiler EGU NOx Rates (lb/mmbtu)	Statewide NOx Budget	Boiler EGU SOx Rates (ppm)	CT CO_2 Cap
Current Trends	**.12 by 2011** **.08 by 2018**	**2691***	**3000 by 2011** **1500 by 2018**	**RGGI**
High Fuel	**.15 by 2013** **.12 by 2018**	**4466***	**3000 by 2011** **1500 by 2018**	**Accelerated RGGI**
Climate Constrained	**.08 by 2013**	**<2691***	**3000 by 2011** **1500 by 2013**	**Accelerated RGGI**
Low Stress	**.12 by 2013** **.08 by 2018**	**2691***	**3000 by 2011** **1500 by 2018**	**RGGI**

*The 2691 ton budget includes 3 industrial boilers and energy generating units greater than 15 MW. The budget for EGUs greater than 25 MW is 2559 tons.

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Environmental Compliance

Information and Direction

- Initiated dialogue between DEP, utilities and Connecticut Generation owners
- Established scenario assumptions for individual Electric Generation Unit (EGU) for each scenario
- Establishing planning levels for Statewide compliance of individual pollutants, particularly NOX and CO2
- Apply multiple scenarios/cases for individual EGU emission rate levels for NOx, Sulfur, CO2 and HG to modeling effort of utilities
- Apply multiple scenarios/cases for statewide targets/caps of individual pollutants.
- Metrics to be produced to demonstrate plan impacts on High Electric Demand Days (HEDD) emissions to enable future working group efforts be captured in procurement planning.

Qualifiers

- Supplemental analysis will build-in DEP air quality regulation changes that are contemplated but not yet adopted
- Generator response to the evolving regulations could vary from the analytical results that the collaborative with utilities will produce.

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Connecticut Generation

1. **Issues**
   - **The utilities analysis of generation Going Forward Cost showed that CT units would continue to operate**
   - **Generation companies maintain the analysis needed to include more costs and risks associated with continued operation, and thus more likely economic obsolescence**
   - **Generation was not assumed to need to invest in upgrades to meet tightening emissions regulations**
   - **Repowering considerations need to be evaluated**
2. **Stakeholders**
   - **Utilities, DEP, Environment Northeast, AARP, NRG, PSEG, Competitive Power Ventures, NEPGA, First Light Power**
3. **Workshops**
   - **Workshops held April 2, 17 and May 5**
   - **Numerous discussions with NRG, First Light and NEPGA**

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NEPGA MEMBERS INPUT TO CONNECTICUT IRP ON REQUIRED MINIMUM REVENUE FOR CONTINUED UNIT OPERATION

NEPGA MEMBERS INPUT TO CONNECTICUT IRP ON
REQUIRED MINIMUM REVENUE FOR CONTINUED UNIT OPERATION

					2010-2011	2011-2012	2012-2013
				CONE	$7.50	$6.00	$4.92
					Auction I	**Auction II**	**Auction III**
					$4.50	$3.60	$2.95
Asset Name	**Units Type**	**MW**	**Cost of Service $/kW-month**		Floor Price as % of Cost of Service	Floor Price as % of Cost of Service	Floor Price as % of Cost of Service
Bridgeport Energy	combined cycle	442	9.52		47%	38%	31%
Milford 1 & 2	combined cycle	489	12.36		36%	29%	24%
NRG Devon 11-14	combustion turbines	119	13.79		33%	26%	21%
NRG Middletown 2-4, 10	fossil steam, CT (10)	770	5.37		84%	67%	55%
NRG Montville 5,6,10 & 11	fossil steam, CT (10, 11)	494	4.84		93%	74%	61%
NRG Norwalk Harbor 1 & 2	fossil steam	330	9.51		47%	38%	31%
PPL Wallingford 2-5	combustion turbines	169	10.85		41%	33%	27%
PSEG Bridgeport Harbor 2	fossil steam	130	8.98		50%	40%	33%
PSEG New Haven Harbor	fossil steam	448	6.97		65%	52%	42%
	Total MW	3,391					
		Average Rate	$9.13		49%	39%	32%

Notes:

Cost of service taken from latest RMR filings and listed in ISO-NE COO Report dated May 9, 2008

Clearing prices for Auction II and III and CONE for Auction III are projections

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Connecticut Generation

Information and Direction

- Initiated dialogue between DEP, utilities and Connecticut Generation owners on continued operation costs
- Attempted secure support of the generation companies to provide:
  1. Some sort of a primer on the way a generating company looks at continued operation of older generation from cost and risk perspectives.
  2. Generic or average cost estimates for these categories by generating unit technology and fuel relevant to Connecticut existing units.
  3. Individual owners' sponsored best available public information to be used with specific units in economic analysis
  4. Support in applying the correct 'potential' retrofit projects, i.e., emissions reduction technologies, for the each unit. The scenarios anticipate the tightening regulations on allowable emissions rates.
- NRG provided technical expertise in identifying likely environmental compliance retrofit projects
- Generation companies via NEPGA maintain the appropriateness of FERC level revenue requirement costs as the proper GFC for determining continued operation

Qualifiers

- Essentially no resolution consensus on how to estimate economic obsolescence
- CEAB analysis will assume utility GFC and environmental compliance project costs in determining the likely retirement cases.
- Generator response to the evolving regulations could vary from the analytical results that the collaborative with utilities will produce.

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Transmission Considerations / ISO-NE Issues

1. **Issues**
   - **The utilities analysis did not evaluate transmission as an option or include costs of transmission variations in the metrics**
   - **NEEWS Project alternatives should be addressed such as generation and DSM, particularly in light of DSM Focus .**
   - **Questions existed on CT Capacity zone/LSR requirements and the needs for quick start operating capacity**
   - **Implications of FCA results on CT Procurement planning regarding transmission implications**
2. **Stakeholders**
   - **Utilities, NRG, PSEG, Competitive Power Ventures, NEPGA, First Light Power, ISO-NE**
3. **Workshops**
   - **May 14th at ISO-NE and follow-up meeting requested by Northeast Utilities**

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Transmission Considerations

Information and Direction

- Based upon our ISO-NE stakeholder meeting and PAC meetings we have established viewpoints on
  - Needs Assessment & Options Analysis Report
  - 2010 FCM Delisting Process Reliability Assessment
  - Additional Connectiuct Areas of Concern (from Nov 07 PAC) ISO-NE
  - LFRM & Daily Second Contingency Dispatch Requirements
  - Their studies on Transmission requirements to support the renewable generation build out
- We will likely run indicative analysis comparing in state generation to proceeding with substantial transmission investment

Qualifiers

- Transmission to support renewables analysis by ISO-NE is not yet complete
- Analysis needs to capture some of the transmission projects under development in Maine
- Connecticut should not be a capacity zone with NEEWS
- Phase II of the current CT Transmission project and the CT procurement dramatically reduce requirements for operating reserves

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APPENDIX F

Connecticut Procurement Activities and Regulations

2008 Comprehensive Plan for the
Procurement of Energy Resources

Prepared by:
The Connecticut Energy Advisory Board

Approved August 1, 2008

PROCUREMENT ACTIVITIES AND REGULATIONS

The State of Connecticut has a number of policies and programs that support financing and expanding energy resources.

This section provides a summary of existing authority to support procuring electricity resources. It briefly describes existing mechanisms found at the wholesale or ISO New England level to support these resources. The objectives of this summary is to provide background to an all-resource analysis of where procurement efforts should be targeted, and to illustrate available authority. It also notes the impact of the various programs in providing capacity to Connecticut.

ISO New England Mechanisms

ISO New England mechanisms that support developing or maintaining energy resources have evolved over time, but the focus has always been on maintaining acceptable reliability levels. Other goals, such as reducing prices, attaining environmental goals, or promoting fuel diversity, have not been the motivating factors for implementing policies or programs.[129] ISO New England has procured "gap" resources to address reliability issues (in particular congested areas, notably southwest Connecticut), and continues to make reliability must run (RMR) payments to certain generators. In addition, ISO New England sponsors a number of load response programs to motivate and support demand reductions as a resource to address peak loads.

ISO New England recently shifted from these procurements and payments to a focus or reliance on market mechanisms to secure capacity resources. In particular, ISO New England recently conducted the first auction to procure capacity resources for the 2010–2011 power year through the Forward Capacity

[129] Attachment K to the Open Access Transmission Tariff (OATT), which was effective on December 7, 2007, and filed in response to FERC Order 890, allows stakeholders to petition ISO to conduct needs assessments of transmission facilities that may reduce production costs or integrate new resources. As such, favorable assessments may provide indirect support to development of energy resources, notably renewable resources that require transmission investment to access the wholesale markets.

Market (FCM). Demand[130] and supply resources are eligible to receive monthly payments in exchange for agreeing three years in advance to provide energy during certain peak hours. Resources are currently receiving payments at predetermined levels during a transition period that ends with the start of the first capacity delivery year in June 2010. Supply resources are also eligible to participate in other shorter-term capacity markets(such as the Locational Forward Reserve Market-LFRM).

Conservation & Load Management

Conservation and Load Management (C&LM) refers to any actions that reduce electricity demand and that occur behind the meter at a customer's premises.

In Connecticut, C&LM has consisted of energy efficiency measures and demand response. Since 1998, these measures and programs have mostly been delivered through non-municipal utility-administered programs[131] funded by a ratepayer surcharge to the Connecticut Energy Efficiency Fund (CEEF). Utilities file plans, with the advice and assistance of the Energy Conservation Management Board, for approval by the Department of Public Utility Control (DPUC).[132]

Revenues collected directly from ratepayers and from participants in these programs are funneled back into the fund to support further investments. Public Act 07-242 allocated a portion of future funds from the quarterly Regional Greenhouse Gas Initiative (RGGI) auctions (beginning in September 2008) to the CEEF. Certain C&LM measures are exempt from sales taxes, reinforcing utility-administered programs.

Public Act (PA) 07-242 further supported C&LM activities: first, meet resource needs with cost-effective C&LM rather than generation resources; second, establish the Electric Efficiency Partnership program, whereby applicants can seek funding approval from the DPUC to support measures that reduce peak electric demand. The program is capped at $60 million per year.

Renewable Portfolio Standard (RPS) Class III includes C&LM measures and thus can generate and sell renewable energy certificates (RECs) to support

[130] Demand response programs will be terminated starting with the first day of the 2010-2011 power year.

[131] Programs delivered by municipal utilities were started in 2006, as required by Public Act 05-1.

[132] On June 19, 2008 (Docket No. 07-10-03), the DPUC approved a $136 million budget for calendar year 2008. This budget is to be funded with current CEEF funds, borrowing from future system-benefit charge collections, and use of non-bypassable federally mandated congestion charges (NBFMCC). Funding for demand-response measures will eventually be eliminated as the FCM transition period comes to an end in June 2010.

investments. PA 05-1 required C&LM measures be eligible to participate in the DPUC RFP processes to procure near-term congestion-reducing measures. This legislative, however, has largely supported generating resources.

Finally, two non-financial mechanisms lend support to C&LM activities. First, PA 05-1 required utilities to implement time-of-use rate plans. Time-of-use rates result in higher rates during peak periods which provides for implementation of load management and other demand-side measures. Second, a number of legislatively-mandated appliance efficiency standards and building codes require installation or use of energy-efficiency measures.

Renewable Generation

Renewable generation refers to larger generating units or to smaller units located behind a customer's meter.

The Connecticut Clean Energy Fund (CCEF) is comprised of revenues collected from ratepayers to help deploy renewable energy (such as solar and on-site renewable generators)[133]. Renewable generation is supported through the RPS by Class I and Class II standards. A portion of the RGGI funds from sales of carbon allowances is to be allocated to CCEF to support Class I renewable generation. Load-serving entities who do not acquire the target amount of certificates, must make alternative compliance payments are directed to CCEF to be invested in Class I resources.

PA 07-242 contained a provision allowing electric distribution companies to procure contracts for RECs for up to 15 years. On June 30, 2008, the DPUC issued a Draft Decision regarding the appropriateness of utilities signing such contracts. In this Draft Decision, the DPUC allowed REC contracts for Class I resources only, but limited rate recovery to new resources. The REC contracts can only be for less than 50 percent of the total RECs produced by a project. Energy and capacity cannot be procured as part of these contracts. Long-term contracts for renewable capacity, known as Project 100, consists of 10-year contracts for at least 150 megawatts of in-state Class I capacity.

Distributed Generation

Distributed generation consists of non-renewable generating resources located on-site, behind the customer's meter. Generally, two forms of distributed generation have been supported or procured: combined heat and power, and emergency generation.

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133 Certain small renewables are exempt from sales and property tax.

Combined heat and power (CHP) with minimum operating efficiencies of 50% are considered RPS Class III resources and, as with renewable generation, are eligible for long-term contracting for their RECs. CHP was specifically mentioned in PA 07-242 as a procurement priority, largely because of its potential for high fuel efficiencies. In addition to the RPS designation, CHP is also exempt from electric standby rates and certain gas transportation charges

Conventional (Non-Renewable) Generation

Conventional (non-renewable) generation has been procured exclusively to address high costs related to congestion or meet reliability criteria. PA 05-1 allowed the DPUC to issue an RFP for long-term contracts for capacity to reduce congestion costs from 2006 to 2010. Though a wide range of resources were eligible to participate in this procurement, the DPUC awarded most of the megawatts to conventional (non-renewable) generation. More recently and as required by PA 07-242, the DPUC issued an order that procures 678 of summer peaking capacity from a number of facilities. It is anticipated that this amount of peaking capacity will reduce the currently high costs paid to generators via the locational forward reserve market.

The DPUC issued a Final Decision in April, 2008 regarding the use of bilateral contracts for energy or energy and capacity, between generators and electric distribution companies to serve standard service load. These contracts will likely be executed with conventional generation resources. The DPUC stated that it would be open to allowing longer-term (ten to fifteen years and beyond) contracts and using the power from these contracts to supply standard service (which was previously prohibited). Costs would thus be passed through the generation service charge (GSC) portion of customers' bills. Using long-term bilateral contracts would depart from current procurement of standard service, which involves overlapping three-year full requirements contracts for all customers (except the large commercial and industrial standard service customers that are served with non-overlapping three-month contracts).

Amount of Capacity and Energy Procured or Supported

Exhibit 1 (below) quantifies the programs or policies discussed above using the megawatts procured through an RFP process or supported through some grant or application for funding. The exhibit contains the latest available data and describes only the major programs. Though only megawatts are shown, some of these programs primarily support energy production. Included, then, is the RPS which supports energy production by renewable and other "clean-energy" generators. Another example is conservation programs that are geared toward energy savings rather than peak load savings.

The data show that a significant amount of capacity has been and is supported by legislatively mandated programs. There is some double counting in the table since some measures, such as demand response, can receive support from both the ISO New England programs and the four Connecticut measures described in this section. The Connecticut efforts totals about 2,600 megawatts plus the financial support provided by the RPS programs (which supports energy rather than capacity). Even assuming that funding for short-term C&LM measures will be eliminated (many of which will still participate in ISO New England demand-response and capacity markets), Connecticut supports over 2,400 megawatts of capacity or over 27% of the actual (with the C&LM impacts) peak load for the state.

Exhibit 1 – Capacity and Energy Procured/Funded or Eligible to be Funded in 2007/2008

Program or Policy	***Megawatts***
ISO Programs	
SWCT ISO New England RFP (expired May 2008)	260
RMR Agreements (as of Dec 2007)	2,445
DR Programs	742
LFRM (Summer 2007)	1,575
FCM Transition Period	All other existing megawatts
Renewable	
Project 150	150
RPS	Energy
C&LM	
Existing Programs[134]	700 + Energy
DPUC RFP for Capacity	5
Distributed Generation	
Emergency Generation and Combined Heat and Power	300
Conventional Generation	
DPUC RFP for Peaking Generation	681
DPUC RFP for Capacity	782
Bilateral Contracts to Supply Standard Service	Energy

[134] Funding for enrollment of new customers providing short-term 05-01 measures to be eliminated in 2008 utility budgets.

APPENDIX G

CEAB Review of Demand-Side Management Opportunities

2008 Comprehensive Plan for the
Procurement of Energy Resources

Prepared by:
The Connecticut Energy Advisory Board

Approved August 1, 2008

CEAB REVIEW OF DEMAND-SIDE MANAGEMENT IN THE IRP

Introduction

On January 1, 2008 United Illuminating and Connecticut Light & Power jointly filed an Integrated Resource Plan for Connecticut to the CEAB for its review consistent with Section 51 of Public Act 07-242. This plan was prepared under the direction of and on the utilities' behalf by The Brattle Group. This appendix reviews the Demand-Side Management (DSM) issues within the Procurement Plan. This review includes: an overview of how DSM potential was evaluated in the 2008 IRP; a summary of input from interested parties concerning DSM; and related CEAB observations and conclusions.

DSM in the 2008 IRP

The IRP included comprehensive documentation of DSM-related assumptions and results. Details of that analysis are set forth in Appendix D of the IRP.

The IRP was developed utilizing a scenario planning approach, where different resource options in the future were analyzed with four distinct plausible future sets of conditions. These included, for example: fuel prices; the electric peak load and energy requirements; the cost of and potential concerns regarding the siting of new generation; and, potential prices for CO_2 allowances. The four scenarios were: Current Trends; Strict Climate; High Fuel/High Growth; and Low Stress. Each scenario is described more fully in the IRP beginning in Section IIB, page 5 and within Appendix B. The analysis included modeling the years 2011, 2013, 2018 and 2030, in order to provide the 3, 5, and 10 year information required by Section 51.

Each of the four scenarios tested the impacts of more DSM by incorporating the DSM Focus Case discussed below.

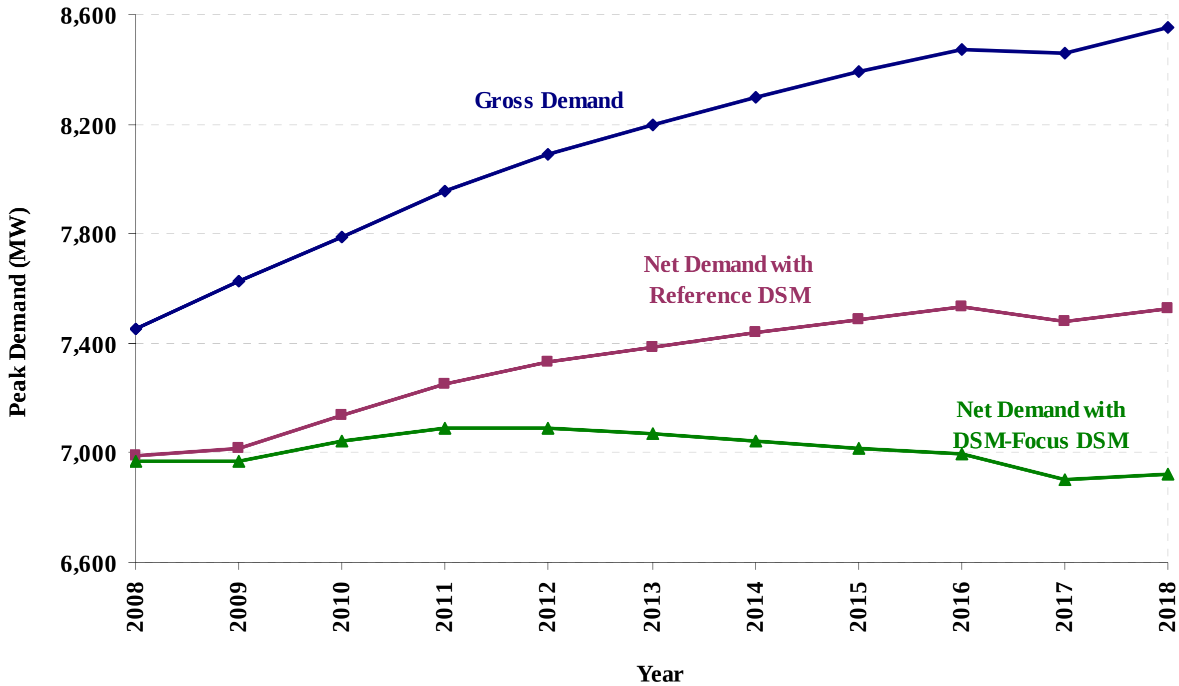
Analysis

The IRP analysis needed to capture the implications and impacts of the DSM potential from two perspectives. First, the IRP needed to include the impacts on peak demand and energy requirements from the DSM measures implemented prior to 2007 and the future outlook for existing and planned DSM, given the expected funding sources. This is captured in what the IRP refers to as "Reference Case DSM".[135] Second, Section 51 provides that DSM be considered the preferred resource such that needs be met first through all available DMS that is cost effective, feasible and reliable. The IRP developed the "DSM Focus Case" to evaluate the merits of a major increase of DSM program funding and measure implementation. The DSM Focus Case in particular and the IRP analysis in general is based on a potential studies performed in 2004. An updated study is being performed currently and results are expected in the fall, 2008. In the absence of an up-to-date assessment of DSM potential, the IRP does a credible job taking into consideration known and expected changes, such as new appliance efficiency standards.

These outlooks were developed for each of the four scenarios. The degree in which these cases have and will impact the peak demand in Connecticut was illustrated in the IRP as shown below for the Current Trends Scenario.

[135] See IRP, page 18.

Figure 2.4: CT Peak Demand (megawatts) Forecast under Different DSM Scenarios[136]



Source: IRP Report January 1, 2008

The IRP describes in detail within Appendix D the documents used as reference material to determine the estimated costs and savings of the Reference and DSM Focus cases. Tables D.3 through D.9 and Figures D.1 through D.6 provide the Peak Demand (megawatts) Savings, the Energy Savings (gigawatt hours) and the costs of these two cases annually through 2018. It is also broken out by utility.

The Reference Case impacts energy requirements by saving 2,821 gigawatt hours in 2018, reduces demand by approximately 12% and sees funding requirements rise from $111 million in 2007 to $146 million in 2018.

The DSM Focus Case impacts energy requirements by saving almost twice the Reference case at 5,387 gigawatt hours in 2018, reduces demand by approximately 19% and sees funding requirements rise to $216 million in 2018. The DSM Focus case was created with a very aggressive ramp up where funding crests at $352 million in 2014. This represents a $200 Million increase from the Reference Case or a tripling of DSM activity and funding from today's levels.

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136 Source: 2007–2016 CT Peak Demand (megawatts) data from ISONE spreadsheet titled "isone_2007_forecast_data.xls." 2007–2018 CT Peak Demand (megawatts) data based on The Brattle Group extrapolation of hourly ISONE data. DSM data for the Reference and DSM-Focus cases provided by the Distribution Utilities.

The scenario analysis used to develop cost, environmental and other metrics developed four resource solutions for future capacity additions, Conventional Gas, Nuclear, Coal, and DSM Focus. The first three incorporated the Reference Case DSM costs and impacts. In the DSM Focus resource solution case any capacity needed in New England were modeled using conventional gas generating capacity.

Findings and Recommendations

The IRP developed many outputs referred to as metrics to compare the relative benefits and costs of the different resource solutions.[137] The IRP offered two findings (*7* and *8*) and one recommendation (*Recommendation 1*) that pertained to DSM directly. (These recommendations appear in the text box below.) They demonstrate the environmental and least cost nature of the DSM Focus Case, as modeled in this analysis. The report also points out that there is a potential increase in average costs per kilowatt hour in the DSM Focus resource solution when compared with the conventional gas option across the scenarios. This would likely translate into higher rates being charged but lower bills for those customers who have participated in the programs. The IRP caveats that the numerical results and thus the conclusions regarding DSM Focus since there were many assumptions made regarding costs and impacts.

IRP Report Findings and Recommendation Pertaining to DSM

7. Nuclear and DSM Mitigate CO_2 Emissions More Effectively than Other Resource Solutions

CO_2 emissions will increase under a Conventional Gas resource solution (though the additional DSM incorporated in all Resource Solutions helps to mitigate this somewhat.) Additional DSM will further limit CO_2 growth, but not cause a reduction. As expected, the addition of nuclear generation would cut a significant amount of CO_2 emissions, while additional coal capacity would increase it. Opportunities for coal with carbon sequestration are limited by a lack of the appropriate geology in Connecticut and New England.

8. Demand Side Management Could Reduce Customer Costs, CO_2 Emissions, and Gas Usage

If achievable as characterized in our analyses, DSM (both demand response and energy efficiency programs) are effective in mitigating future peak and energy growth. The analyses assume a substantial amount of “Reference Case” DSM in all Resource Solutions (for example, much more than assumed by the ISO in its load projections), and still more DSM in the DSM-Focus solution. This additional DSM, if it is similarly effective, would also be valuable. (This analysis has not attempted to optimize the type or quantity of DSM programs, but simply evaluated two different levels of specified DSM programs.)

The results show that DSM can reduce overall customer costs. Under some circumstances, DSM can increase average unit costs (cents per kilowatt hour). When consumption volumes are changing, a change in unit costs may not accurately reflect customer impacts. How costs are recovered from particular customers or classes can affect whether their rates and/or costs go up or down. This is a question of cost allocation, a ratemaking issue not addressed here.

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[137] The results are discussed and shown in the IRP, Section III. Detailed output information and documentation is provided in Appendix H. The IRP findings and conclusions as contained in Appendix B of this Procurement Plan.

Recommendation 1: Maximize the use of demand side management (DSM), within practical operational and economic limits, to reduce peak load and energy consumption.

The potential for increased DSM to reduce customer costs, gas usage, and environmental emissions demonstrated in this analysis suggests that DSM should be pursued more aggressively. State regulatory authorities should examine, and where possible, explore methods to implement additional, cost-effective DSM. This would facilitate utility DSM programs to exceed current levels and expand upon the success of existing DSM programs. While the need for capacity is several years off in Connecticut, DSM programs are more cost-effective if they are pursued consistently over time, so it is reasonable to begin the ramp-up to more aggressive DSM programs in the near term.

The DSM resource investments assumed in this report far exceed the (already aggressive) levels pursued by the Distribution Utilities to date. The pace and magnitude of this expansion warrants careful monitoring of resource availability, costs, and operational effectiveness as the programs develop over time.

Public Comment and Stakeholder Input

The CEAB received input in on DSM through receipt of Written Comments; a public hearing; and, stakeholder workshops.

Public Comments

Public comments suggested strong support for the IRP plan's recommendation to further expand the DSM programs. Favorable comments were received from the ECMB, environmental groups, and citizens. On the other hand, generators noted concern about the reliability of demand response and the ability to accomplish such an aggressive energy efficiency program. The generators' did not oppose DMS or its economics but expressed concern about risks associated with resources that may offer less reliability than other options. These observations are summarized in greater detail at:
http://www.ctenergy.org/Procurment_Plan_Review.html

These comments, and the CEAB's preliminary assessment on the IRP informed the CEAB's decision to review DSM in a Stockholder process conducted in collaboration with the Distribution Utilities.

SUMMARY OF PUBLIC COMMENT ON THE DISTRIBUTION UTILITIES' RECOMMENDATION No. 1[138]

Maximize the use of demand side management within practical, operational and economic limits, to reduce peak load and energy consumption.

The first Recommendation in the Distribution Utilities' Plan is to maximize the use of demand side management ("DSM") within practical, operation and economic limits to reduce peak load and energy consumption received particularly broad support.[5] The Energy Conservation and Management Board ("ECMB") stated that it and its consultants worked closely with the Distribution Utilities on the DSM portion of the Plan. The ECMB concluded that the Plan established ambitious, achievable energy and peak demand savings targets for DSM programs through 2018 as part of overall effort to achieve all cost-effective energy efficiency and demand reduction. According to the ECMB, the only "economic limit" that should be applied for "maximizing the use of DSM" is demonstration of conservation and load management program cost-effectiveness. The current "economic limit" constraining the such programs, program funding levels, must be addressed by increasing funding for the programs in 2008 and future years.

Many commentators encouraged immediate implementation and funding of DSM irrespective of whether other central elements of the Plan are ready to move forward at this time. The vast majority of individuals (speaking as citizens rather than as representatives of an organization) strongly supported this element of the Plan. One commentator observed that increasing DSM is the only aspect of the Plan that involved immediate action: all others called for exploration, evaluation or consideration.[6] Other commentators expressed concern that the Plan's DSM goals are overly aggressive, lack cost-effectiveness analysis, cost-comparisons to other resources and a feasibility assessment.[7] Several commentators stated that the Plan overstates the ability of DSM to maintain reliability within practical and economic limits.[8] Additionally, one commentator observed that the Plan did not address potential funding mechanisms to implement DSM, including those that would complement current ratepayer funded programs to minimize ratepayer costs, such as building codes or appliance standards or combined heat and power.[9]

5 See, American Lung Association cover letter; CMEEC at 3; Clean Water Action at 2-3; ECMB at 1 -2; Environment Northeast at 1, 7-8; NEEP at 1-3. In addition, the vast majority of the individuals who sent e-mails to the CEAB focused exclusively on, and in strong support of, DSM.

6 See, Environment Northeast at 3.

7 See, Firstlight 5; New England Power Generators Association at 11; NRG at 7-10.

8 See, Firstlight at 6; New England Power Generators Association at 11.

9 See, AARP at 3, 12.

CEAB Initial Critique

The CEAB's preliminary assessment of DSM in the IRP was very favorable.[139] The Distribution Utilities' DSM recommendation is consistent with Section 51(c)'s direction that resource needs shall first be met through all available

[138] See the "2008 Integrated Resource Plan CEAB Review Status Report" for consideration by the CEAB at the March 7, 2008 Meeting. The same report is in Appendix D.

[139] The box in this section has extracted them from the report provided in Appendix C of this Procurement Report.

energy efficiency and demand reduction resources that are cost-effective, reliable and feasible. Further, the Plan contains a meaningful assessment of the DSM potential needed to eliminate growth in energy in demand. However, more work needs to be done on how best to accomplish the goal and to ensure the customer cost impact of demand-side resources are reviewed on an equitable basis with non-demand side resources. With regard to the suggestion that the DSM move forward immediately irrespective of other unresolved issues in the Plan, the CEAB suggests the level of cost-effective DSM should be identified in the context of the overall Plan.

Excerpts from the CEAB Preliminary Assessment on the DSM Provisions in the Integrated Resource Plan for Connecticut dated January 28, 2008[140]

Section II B:
The Manner Of How Best To Eliminate Growth In Electric Demand

The Distribution Utilities' assessment shows scenarios that accomplish the elimination of load growth. The Distribution Utilities have extended the existing available information on the maximum potential for DSM to illustrate the characteristics of the program that would be needed to accomplish the elimination of load growth. The Distribution Utilities' IRP presentation of this aggressive DSM scenario is helpful new information needed to consider such an aggressive DSM initiative.

The cost effectiveness of and demand reduction actions, whether they be programs offered by the utilities or building code changes does not appear within this report. The report (pages D-1 to D-2) refers to the cost-effectiveness for the DSM Focus plan only as "the estimate assumes that all measures that pass the Total Resource Cost (TRC) test are implemented…".

As is clearly stated in the Distribution Utilities' IRP, this assessment is not an implementation plan and it has not necessarily developed an optimal (or the "best") approach to accomplish this objective. This assessment does point to additional studies that should be conducted to allow future planning cycles to more fully address this requirement (Companies' IRP, Appendix D, pages D-20 to D-21).

Section II C:
How Best To Level Electric Demand In The State By Reducing Peak Demand And Shifting Demand To Off-Peak Periods

The compliance on this is similar to the prior requirement on Electric Demand for very similar reasons. The Distribution Utilities' IRP offers an aggressive scenario and information to consider in expanding this resource, however, the information base is not yet sufficient to have a full assessment of the best approach to eliminating growth in Peak Demand.

Section III C:
Specify The Extent To Which Demand-Side Measures, Including Efficiency, Conservation, Demand Response And Load Management Can Cost-Effectively Meet These Needs

The Distribution Utilities' review and adaptation of the existing studies in this area identified the need to conduct a comprehensive update to this study. The Distribution Utilities note that ECMB is planning such a study in 2008.

Time did not allow the Distribution Utilities to conduct a new and comprehensive study for January 1, 2008. In lieu of that, the 2004 work was adapted to provide the best readily available estimate. In context, this assessment complies with the requirement.

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140 See Appendix C for the entire text of this assessment.

Section IV A:
Approaches To Maximizing The Impact Of Demand-Side Measures

Program portfolios are comprehensive, and together with the Distribution Utilities Supplemental Filing referred to in (i) above represent a reasonable consideration of approaches to maximize the impact of DSM measures as required by the Public Act.

Stakeholder Input Workshops

The CEAB and the Distribution Utilities collaboratively sponsored two Stakeholder Workshops on DSM. During these workshops, the CEAB received input from the ECMB consultants and the Distribution Utilities' C&LM staff that helped review DSM analysis in terms of scope, cost and practical potential of the expansion of Energy Efficiency and Price Responsive Demand. The three principle areas discussed at the Stakeholder workshops included:

Cost effectiveness process. What were the economic tests used to determine whether any of the programs were cost effective? The ECMB and the DPUC use the Total Resource Cost (TRC) test, which is an industry standard. This test is favored by the CEAB as well. However the way the test was incorporated by association. The basic programs in the Reference DSM Case were extrapolations of currently approved and TRC tested programs. The DSM Focus cases were predicated on programs with basically the same costs assumptions as the current programs.

Capability to ramp up programs. There was both concern and confidence expressed during the workshop discussions about ramp up capability. The DSM Focus programs were assumed to have proven delivery mechanism similar to current programs. It was suggested that the high degree of customer demand for program participation given the cost of electricity today and the strong financial incentives with in the programs is reason to believe that customer participation will be strong and targets attainable. ECMB expects that high consumer demand levels for the programs are indicators of the capability to aggressively scale up programs.

There was concern about the ability to obtain the DPUC's approval of funding since the current funding mechanisms were all incorporated into the Reference DSM Case. Table 1 below, provided by the ECMB during the stakeholder process, shows that the DSM Focus case, if implemented according to the assumptions in the IRP analysis, would require the DPUC to collect as much as $218 million more from ratepayers in a given year. This assumes no changes in program designs to reduce costs or finding alternative funding mechanism.

Funding Sources for DSM expansion. Table 1 also shows that funding for DSM programs is expected to come from three known sources in addition to the $3 per megawatt hours collected to fund the CEEF. The Forward Capacity Market (FCM) run by ISO New England allows for payments to be made to qualifying energy efficiency and demand response programs. There are revenues expected to fund energy efficiency as CLASS III renewables. And, there is the potential for as much as $35 million that could be earmarked to fund DSM from the sale of CO_2 allowances under the RGGI program. Even with those funding sources, the shortfall in the DSM Focus Case is still about $180 million in some years.

During the Stakeholder process, ECMB asked CEAB to formally support its request to the DPUC to immediately bring energy efficiency funding to the levels established as economic in the utilities projects and identified. CEAB agreed in general about the benefits of increasing DSM, but was not far enough along in its analysis at that time to offer support for specific funding requests.[141]

Table 1 Illustration of Potential DSM Funding[142]

DSM Focus Solution: 2008 IRP ECMB, 5/1/08

Annual Budget ($ million) - CL&P and UI

CL&P and UI		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
EE	Total EE	92.3	125.4	176.4	240.1	287.1	311.6	312.4	269.4	206.3	175.6	176.3
DR	Load Response	27.9	27.6	27.6	27.7	27.7	27.7	27.8	27.8	27.9	27.9	28.0
	Res. DLC	2.9	6.4	9.6	12.0	13.2	12.2	12.2	12.3	12.4	12.5	12.5
	Total DR	30.8	33.9	37.2	39.6	40.8	39.9	39.9	40.1	40.2	40.4	40.4
Total Budget		123.1	159.4	213.7	279.7	328.0	351.5	352.3	309.5	246.5	215.9	216.8
Revenues & Funding Sources												
Funding Sources	C&LM (3 mils) EE	81.4	92.0	92.2	92.4	92.6	92.8	93.0	93.2	93.4	93.6	93.8
	FCM EE	1.8	2.1	4.4	7.2	8.9	10.7	12.4	14.2	15.9	17.7	19.5
	Class III EE	2.3	4.5	6.0	6.0	6.0	5.9	5.9	5.9	5.9	5.8	5.8
	FCM DR*	27.9	27.6	27.6	27.7	27.7	27.7	27.8	27.8	27.9	27.9	28.0
Total Estimated Revenues		113.3	126.2	130.2	133.2	135.2	137.1	139.1	141.1	143.1	145.1	147.0
Difference (Budget - Revenues)		9.9	33.2	83.5	146.5	192.7	214.4	213.2	168.5	103.4	70.9	69.7

* FCM DR partially funded by FMCCs in 2007-2009

2nd Total (check-Brattle)	123.1	159.4	213.7	279.7	328.0	351.5	352.3	309.5	246.5	215.9	216.8

Estimated Potential RGGI Revenues - C&LM Programs in CL&P and UI Service Territories ($ million) ECMB, 5/1/08

	Market Price $ Per Short Ton	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Estimated	$2.00		14	14	14	14	14	14	14	14	14	14
Range	$5.00		35	35	35	35	35	35	35	35	35	35

Assumptions:
Allowances 10,695,036 (short tons)
% to C&LM 66%
Total allowances sold in each year assumed to equal allowances for that compliance year (i.e., any portion of allowances delayed is offset by pre-selling of allowances from future compliance years)
Decline in allowances beginning in 2015 (2.5% per year) assumed to be offset by increase in market price for allowances

A final DSM-related issue that arose during the stakeholder process was a discussion of procurement planning in terms of energy requirements. Concern was expressed that the CEAB analysis was defining need in the context of capacity and not energy. The ECMB letter to the CEAB (Attachment 2) sets forth its view of Section 51 in this respect.

141 Attachment 1 of this appendix is the letter ECMB sent requesting CEAB support. Attachment 4 is the CEAB letter to the DPUC.

142 Source: ECMB.

Concurrent DPUC Proceeding on the DSM Budgets

During the CEAB review of the IRP and Stakeholder Workshops, the DPUC was in the midst of Docket No. 07-10-03, DPUC Review of CL&P and UI's Conservation and Load Management Plan for the Year 2008. The CEAB did not participate in that matter, nor did it conduct a detailed examination of the record.

ECMB Concerns

The ECMB requested as part of the DPUC proceeding for more funding for programs based partially on the results of the Distribution Utilities' IRP (see Attachment 5). The ECMB submitted another letter (Attachment 3) to the DPUC concerning the DSM funding approved by the DPUC in its Draft Decision in Docket 07-10-03. In short, the ECMB's principal concern was that funding was below levels needed to meet the large demand for participation by commercial and residential customers and would not enable the ramp up of programs to begin to achieve the expansion of objectives in the DSM Focus case.

DPUC Decision Docket No. 07-10-03

The DPUC issued a Final Decision concerning the 2008 CEEF budget on June 18, 2008. In short, the Department approved funding to support current program requirements and noted that it would review the IRP and associated legislative requirements upon receipt of the Plan from the CEAB. The Final Decision further cautioned that increased DSM spending should not be assumed prior to approval and that overall spending levels should be primarily driven by the need for resources to meet future electric demand and energy requirements.

In addition, the DPUC indicated its belief that it was necessary to adjust the incentive structure of all programs so as to continue this evolution and to meet the growing demand for the programs. Accordingly, the Department initiated a proceeding to examine:

- Increasing effort on peak demand savings.
- Eliminating funding for non-electric savings in all programs except Low Income.
- Reduce funding for non-electric Low Income program.
- Providing joint programs by combining gas, oil and electric funds to lower administrative costs.
- Reducing incentive levels where appropriate.
- Adding new emphasis on market transformation by changing building codes or appliance efficiency standards.

- Adding more emphasis on loan programs and performance-based contracting.

At the time of this writing, that review is ongoing.

Observations

The CEAB review processes described above lead to several observations regarding DSM.

1. DSM Focus implementation would be beneficial in the long term

DSM Focus has passed two levels of cost-effectiveness testing. The TRC testing of the DSM programs shows long term benefits. The IRP shows a reduction in annual total costs as a result of implementing DSM Focus. The IRP analysis shows that average costs per KWh can increase especially in the early years of implementation, creating the need to balance short term and long term objectives.

2. DSM Focus has not as yet been optimized.

Discussions with the ECMB and the C&LM staffs of the utilities acknowledged that there was little time to conduct means by which to incorporate alternative DSM funding mechanisms, such as private lending institution involvement or variations in program incentives.

3. There is uncertainty around the potential costs and impacts of the DSM Focus case.

The Distribution Utilities' provided caution within their Recommendation on DSM. They acknowledge results are specific to the inputs provided. The principal change in the DSM assumptions could arise out of the new DSM potential study being conducted on behalf of ECMB that will be concluded in the fall of 2008.

4. There is some legitimacy to the concern that the IRP has not tried to specifically address planning for energy needs with DSM.

There were no specific metrics other than LMP related to energy costs in the IRP analysis. There did not appear to be programs in DSM Focus aimed specifically at meeting energy needs.

CEAB Conclusions

1. There is value in adopting DSM Focus objectives today

If the DPUC adopts the long term objectives of DSM Focus, there are important ramifications to resource acquisition activities in the near term. The evaluation of bilateral contracts, long term REC contracts and even transmission upgrades needs could be effected if there is a delay at adopting DSM Focus objectives. Bilateral contracting would involve the purchase of energy or capacity in order to manage risks and/or lower expected costs to Connecticut ratepayers. The contracts would then need to be compared to the Distribution Company's outlook for future prices. This outlook for the future prices for energy or capacity needs to be derived form some analysis that at least probabilistically includes retirements.

2. Final DSM Acquisition Decisions May be Informed by Further DPUC Analysis.

There are varied opinions concerning whether DSM resource acquisition decisions must conform to the IRP analysis. In the CEAB's view, resource acquisition should conform to the Plan as ultimately approved by the DPUC, which will be informed by further analysis as indicated in the Final Decision in Docket No. 07-10-03.

Attachments to Appendix G

1. Request for Expedited CEAB Approval of the 2008-2009 C&LM Funding Increases Proposed in the 2008 Integrated Resource Plan (April 10, 2008)
2. Comments on the 2008 Integrated Resource Plan based on the June 26, 2008 Meeting with the CEAB Consultants (June 27, 2008)
3. ECMB Comments on the Draft Decision 2008 Conservation and Load Management Plan Docket No. 07-10-03 (June 9, 2008)
4. CEAB Recommendation on the 2008-2009 C&LM Program Funding (May 13, 2009)
5. DPUC Review of The Connecticut Light and Power Company’s and The United Illuminating Company’s Conservation and Load Management Plan for the Year 2008 [07-10-03] (February 25, 2008)

State of Connecticut
Energy Conservation Management Board (ECMB)

Request for Expedited CEAB Approval of the 2008-2009 C&LM Funding Increases Proposed in the 2008 Integrated Resource Plan

April 10, 2008

On February 7, 2008 the Energy Conservation Management Board (ECMB) submitted comments on the Integrated Resource Plan for Connecticut prepared by Connecticut Light & Power and United Illuminating (the Distribution Utilities). The Plan was prepared pursuant to Section 51 of Public Act 07-242, An Act Concerning Electricity and Energy Efficiency, which requires the electric distribution companies to submit a comprehensive resource plan to the Connecticut Energy Advisory Board (CEAB).

In its February 2008 comments, the ECMB:

1. Found that the Plan established ambitious yet achievable energy and peak demand savings targets for the demand side management (DSM) programs through 2018 as part of the overall effort to acquire all cost-effective energy efficiency and demand reduction resources, as required by PA 07-242.[143]
2. Supported the findings and recommendations in the Plan to aggressively increase cost-effective DSM programs and funding, in order to maximize the benefits for Connecticut.
3. Recommended the expeditious implementation of the first five years of the DSM-Focus solution set forth in the Resource Plan.
4. Recommended that expeditious ramp up to increased levels of DSM and Conservation and Load Management (C&LM) program activity should begin in 2008.
5. Recommended that, while the CEAB may have concerns about the completeness and level of detail of some portions of the Resource Plan, the DSM portion of the Plan, supported by the successful track record of and expanding customer demand for the cost-effective C&LM programs, is adequate to support a CEAB recommendation to proceed aggressively to implement the first five years of the DSM-Focus strategy.

The ECMB understands the CEAB will review the Plan through July 2008, and submit a report and modified Plan to the Department of Public Utilities (DPUC) on August 1, 2008. In light of this revised CEAB review schedule, the ECMB respectfully requests the CEAB approve and recommend to the DPUC the early, expeditious ramp up of DSM and the C&LM programs,

[143] Section 51(c) of PA 07-242 states: "Resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible."

supported with Procurement Plan funding. Specifically, the ECMB requests CEAB approve and recommend to the DPUC:

1. The expeditious ramp up of the C&LM programs, beginning in 2008, as part of the overall effort to acquire all cost-effective energy efficiency and demand reduction resources, as required by PA 07-242.
2. The increases in 2008 and 2009 C&LM funding levels set forth in the Plan, which are necessary to support the ramp up of the C&LM programs. The proposed increases in C&LM funding are $9.9 million in 2008 and $33.2 million in 2009, to be funded through the Procurement Plan process.[144]
3. C&LM funding flexibility to encourage and support a faster ramp up to the higher levels of C&LM program activity. The 2008 and 2009 C&LM funding increases should be viewed as floors, and additional funding should be made available if the cost-effective C&LM programs can be expanded and ramped up more quickly than represented in the Plan.

The DSM-Focus solution set forth in the Plan is reasonable and achievable, and the savings resulting from the implementation of the DSM-Focus solution will reduce total customer costs and help meet Connecticut’s energy, climate, and environmental goals. The ECMB strongly recommends the expeditious implementation of the first two years (2008 and 2009) of the ramp up of the DSM-Focus solution, beginning as soon as possible in 2008. This would also allow the ECMB and the Distribution Utilities to incorporate the DSM-Focus initiatives and level of effort into the 2009 C&LM Plan, which is to be submitted to the DPUC on October 1, 2008.

The program concepts and strategies that will be used to achieve the 2008 and 2009 DSM savings targets in the Plan are based on the sound design and proven track record of the existing C&LM programs. However, the C&LM programs are currently facing overwhelming demand from customers and are becoming over-subscribed. The C&LM programs are in a vulnerable transition period with escalating customer demand and expanding programs and strategies, while being severely limited by current budget constraints. Connecticut consumers and businesses may lose some opportunities to reduce their energy costs unless an increased financial commitment is made.

There is broad public support for Recommendation No. 1 of the Plan, to maximize the use of DSM to reduce peak load and energy consumption. In its March 7, 2008 Status Report, the CEAB noted that the vast majority of public commentators strongly supported the DSM element of the Plan, and “many commentators encouraged immediate implementation and funding of DSM irrespective of whether other central elements of the Plan are ready to move forward at this time.”[145] CEAB approval of an early, expeditious ramp up to higher levels of C&LM program activity would be responsive to public input, and the expanded programs would help customers reduce their energy costs sooner than waiting until after the full Plan is reviewed by the CEAB. Early ramp up and expansion of the C&LM programs in 2008 and 2009 would provide significant benefits, and there is no meaningful downside for Connecticut for several reasons:

1. Any modified Plan resulting from further CEAB review in 2008 is very likely to recommend increasing C&LM significantly, similar to the Distribution Utilities’ Plan,

[144] The CL&P C&LM funding increases are $9.2 million in 2008 and $26.0 million in 2009. The UI C&LM funding increases are $0.7 million in 2008 and $7.2 million in 2009.

[145] CEAB Review Status Report; March 7, 2008; page 3.

because there is a large amount of cost-effective DSM available in Connecticut,[146] and PA 07-242 requires the acquisition of all available cost-effective DSM.

2. There is much more DSM available in Connecticut than the amounts proposed in the Plan for 2008 and 2009. The DSM budget and savings amounts in the Plan for 2008 and 2009 are based on estimates of how quickly the C&LM programs could ramp up and expand to achieve additional savings – and not on the total amount of DSM available.
3. DSM is a flexible resource consisting of many small units. Early ramp up will not limit or restrict the CEAB in its review of DSM resources for future years.
4. All C&LM programs are required to be cost-effective.
5. There is significant oversight and regulatory review of the C&LM programs. The ECMB reviews and provides recommendations on C&LM program design, implementation, cost-effectiveness analysis, savings goals, and evaluation results. The DPUC reviews and approves the programs and the C&LM plans, and monitors C&LM portfolio and program performance. In fact, the DPUC would have to review and approve any proposed 2008 and 2009 early ramp up of the Resource Plan prior to its implementation.

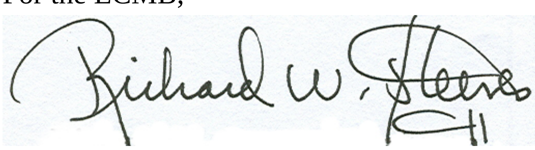
Also, it is not necessary to identify the precise amount of cost-effective energy efficiency and demand reduction resource potential available in Connecticut in order to expand the C&LM programs in the first two years.

The most important action for Connecticut is to begin the ramp up and expansion of cost-effective DSM as soon as possible in 2008, and utilize the present C&LM momentum to achieve the goals set forth in the Resource Plan. Therefore, the ECMB recommends the expeditious implementation of the 2008 partial year and 2009 full year of the DSM-Focus solution.

The ECMB respectfully requests the CEAB consider and act on the ECMB recommendations in a timely manner, at or prior to its May 2, 2008 meeting. The ECMB and Companies are available to answer any questions and provide additional information as needed.

Thank you for the opportunity to submit this request regarding the Integrated Resource Plan, and for the ongoing coordination between the CEAB and the ECMB.

For the ECMB,



Richard W. Steeves
Chairman

[146] As documented in the Final Report of the Energy Efficiency Achievable Potential Study, prepared for the ECMB, June 2004. The ECMB is conducting a potential study in 2008 to update the results of the 2004 study.

State of Connecticut
Energy Conservation Management Board (ECMB)

Comments on the 2008 Integrated Resource Plan based on the June 26, 2008 Meeting with the CEAB Consultant

June 27, 2008

On June 26, 2008 a representative of the Energy Conservation Management Board (ECMB) participated in a meeting led by John Athas, the consultant working for the Connecticut Energy Advisory Board (CEAB) on the review of the 2008 Integrated Resource Plan (IRP). As a follow up to the meeting yesterday, the ECMB provides written comments on two issues below.

1. The IRP must address both energy and capacity resource needs.

Section 51 of PA 07-242 provides for a two-step process in which the electric companies first provide an assessment of future energy resource needs. In particular, these include the energy and capacity requirements of customers for the next three, five, and ten years, and how best to eliminate growth in electric demand. These requirements establish the resource needs which are to be met through the comprehensive procurement plan. The statute then requires the development of a plan which first utilizes all available energy efficiency and demand reduction resources to meet the energy and capacity needs identified in the assessment.

However, the Integrated Resource Plan (IRP) Section II-C (p.8) concerning Quantification of Resource Needs focuses exclusively on future capacity (megawatts) requirements and the need for "additional resources" to meet these requirements. It does not present a quantification of future energy requirements as required by the statute. This is particularly important because the major cost driver for future electricity prices is the escalating fuel prices for energy. We believe this has led to some confusion as to whether the IRP requirements are satisfied if future capacity needs are met by actions that the DPUC and ISO New England have already undertaken.[147]

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[147] The following excerpts from the DPUC Decision in Docket No. 07-10-03, DPUC Review of CL&P and UI Conservation and Load Management Plan for the Year 2008, illustrate the need for including energy requirements.

"Customer demand does not satisfy the needs assessment. Last year and again in this proceeding, the Distribution Utilities and the ECMB on several occasions have stated that the increased demand for conservation has resulted in greater than budgeted expenditures in 2007 and is expected to result in overspending again in 2008. One of the primary benefits of the conservation programs is that it helps customers to reduce their electric bills. Customer demand is important, particularly for determining which programs should be offered as well as the appropriate

Clearly, the IRP requirements have not been met without a full examination of how to minimize the cost and environmental impacts of both energy and capacity resources.

Fortunately, the analysis that was carried out in the IRP provides a basis for examining the energy issues because it includes the cost impacts of energy usage in the various scenarios, including the DSM Focus scenario. What is needed is a broadening of the Quantification of Resource Needs section to include the energy resource needs, together with a recognition that these needs should first be met through cost-effective demand-side measures (consistent with the requirements of PA 07-242), and then by the most beneficial supply alternatives in terms of cost and environmental impacts.

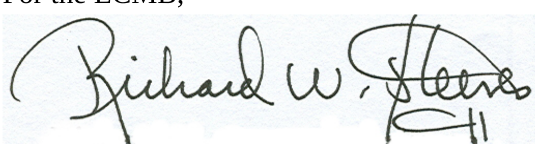
2. C&LM program spending (current in 2008 and forecasted in 2009) is exceeding the levels set forth in the DSM Focus scenario of the IRP.

The DSM Focus scenario in the IRP included C&LM program spending increases of $9.9 million in 2008 and $33.2 million in 2009. These increases are necessary to support the ramp up of the C&LM programs, to meet the requirements of PA 07-242, and to respond to very strong customer interest in the programs. The C&LM ramp up is ahead of the plan set forth in the IRP.

The current level of C&LM spending in 2008, as recently approved by the DPUC in Docket No. 07-10-03, exceeds the level set forth in the DSM Focus scenario of the IRP. In addition, the ECMB estimates that the level of C&LM spending in 2009 will also exceed the level set forth in the DSM Focus scenario. The ECMB is currently updating its forecast of 2009 C&LM expenditures and will provide its updated estimate to the CEAB on or before July 10, 2008.

Thank you for the opportunity to submit these comments regarding the Integrated Resource Plan, and for the ongoing coordination between the CEAB and the ECMB.

For the ECMB,



Richard W. Steeves
Chairman

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incentive levels. However, overall spending levels should be primarily driven by the need for resources to meet future electric demand and energy requirements. CL&P's indicates that no new capacity is needed until 2013-2014. CL&P Response to Interrogatory EL-18." (p.14)

"The IRP predicts that Connecticut will not face a resource shortfall during the 10-year forecast period, taking into account the impact of DSM initiatives, the effect of Project 150, distributed generation additions, forward capacity auctions, and expected peak capacity additions. Despite the lack of need for new resources, the IRP calls for significant increases in the C&LM budget -- rising to $236 million in 2011 and peaking at $338 million in 2014 -- maximizing the use of DSM within practical operational and economic limits, to reduce peak load and energy consumption. IRP, pp.-ES-1 to ES-5; D-19." (p. 15)

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State of Connecticut
Energy Conservation Management Board (ECMB)

Comments on the Draft Decision
2008 Conservation and Load Management Plan

Docket No. 07-10-03

June 9, 2008

The Energy Conservation Management Board (ECMB) appreciates the opportunity to review the Draft Decision in Docket No. 07-10-03 regarding the 2008 Conservation and Load Management (C&LM) Plan. The ECMB provides the following comments.

1. **The Department should approve additional funding for the 2008 C&LM and EIA programs, as proposed in the 2008 Plan[148] and supported by the ECMB, to benefit customers and respond to customer demand for the programs, and to support the ramp up to the increased level of C&LM program activity necessary to meet the requirements of PA 07-242.**

   The Draft Decision proposes to limit 2008 C&LM expenditures to levels significantly less than the current forecasts of customer participation in the programs. Draft Decision, p. 3-6. In addition, the C&LM budget level proposed in the Draft Decision would not be adequate to meet the requirements of PA 07-242.

   A. Additional C&LM funding is needed to benefit customers and respond to customer demand.

   The C&LM programs are cost-effective and reduce total costs for customers, and they provide reliable energy and capacity resources.[149] The C&LM programs help customers reduce their energy costs and mitigate the effects of rising energy prices. Apparently, high customer interest in and demand for the C&LM programs is due at least partly to many customers realizing that increasing energy efficiency is the best way to reduce their energy costs.

[148] Including the updated forecasts of 2008 participation and expenditures in the Exhibits in Docket No. 07-10-03.

[149] The net rate impacts of the C&LM programs are also low, and are mitigated by the DRIPE effects. Draft Decision, p. 9-10; CL&P response to EL-15.

The increased customer interest and demand is a good thing, which should be embraced and encouraged, and it should not be dampened or discouraged. Therefore, the Department should provide funding adequate to meet forecasted customer participation, and the Department should not dampen or limit customer participation in cost-effective C&LM programs by restricting funding in the manner proposed in the Draft Decision.

B. Additional C&LM funding is essential to support the ramp up to the increased level of C&LM program activity necessary to meet the requirements of PA 07-242.

PA 07-242 requires the acquisition of all cost-effective energy efficiency and demand reduction resources that are reliable and feasible.[150] While the Connecticut Energy Advisory Board (CEAB) has not completed its review of the first Integrated Resource Plan (IRP) submitted on January 1, 2008 (a parallel requirement of PA 07-242), it is clear that increasing the C&LM programs will be an essential element of any plan to meet the legislative requirements.[151] Any modified IRP resulting from further CEAB review in 2008 is very likely to recommend increasing C&LM significantly, similar to the Distribution Utilities' IRP and consistent with the increased funding requested in the 2008 Plan, because there is a large amount of cost-effective DSM available in Connecticut,[152] and PA 07-242 requires the acquisition of all available cost-effective, reliable, and feasible DSM.

In its communications with the Department and the CEAB, the ECMB has recommended that the C&LM programs begin the ramp up to the increased levels of effort and activity necessary to meet the requirements of PA 07-242. This ramp up is consistent with the intent and requirements of PA 07-242.

The C&LM funding limitations proposed in the Draft Decision would result in some cost-effective, reliable, and feasible energy efficiency measures not being installed, which is counter to the requirements of PA 07-242. The Department should approve 2008 C&LM funding adequate to implement all cost-effective, reliable, and feasible energy efficiency and demand reduction measures that can be acquired during 2008.

[150] Section 51(c) of PA 07-242 states: "Resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible."

[151] In its March 7, 2008 Status Report, the CEAB noted that the vast majority of public commentators strongly supported the DSM element of the Plan, and "many commentators encouraged immediate implementation and funding of DSM irrespective of whether other central elements of the Plan are ready to move forward at this time." CEAB Review Status Report; March 7, 2008; page 3.

[152] As documented in the Final Report of the Energy Efficiency Achievable Potential Study, prepared for the ECMB, June 2004. The ECMB is conducting a potential study in 2008 to update the results of the 2004 study.

C. The CEAB supports the early ramp up of the C&LM programs, beginning in 2008.

In its May 13, 2008 letter to the Department, the CEAB "recommends that the DPUC approve the ramp up of the C&LM programs, particularly energy efficiency programs, beginning as soon as possible in 2008, as part of the overall effort to acquire all cost-effective energy efficiency and demand reduction resources, as required by PA 07-242." CEAB letter, May 13, 2008.

2. The Distribution Utilities, as the C&LM program administrators, should be directed to continue the ramp up of the C&LM programs, while continuing to review incentive levels and other expenditures, and make adjustments as appropriate to ensure the effectiveness and cost-efficiency of the programs, with input from and review by the ECMB.

In developing the 2008 Plan and the first years of the DSM section of the IRP, the Distribution Utilities have generally acted in a manner consistent with the recommendations of the ECMB and consistent with the requirements of PA 07-242. The ECMB has not acted with an "apparent lack of regard for the C&LM budgets approved by the Department." Draft Decision, p. 5. Rather, the ECMB has recommended, and the Distribution Utilities have implemented, a plan to begin the ramp up of the C&LM programs to the level necessary to meet the requirements of PA 07-242, which is also described in the early years of the DSM section of the IRP. The ECMB believes these actions and plans for increased C&LM efforts and funding are appropriate in light of PA 07-242, and the ECMB has communicated to the Department its recommendations regarding such a ramp up as well as support for encouraging and responding to increased customer demand.

In parallel, the Distribution Utilities, in their role as program administrators, and with ECMB input and review, have analyzed incentive levels and other expenditures, and have made adjustments as appropriate to ensure the effectiveness and cost-efficiency of the programs. The ECMB and the Distribution Utilities proposed revisions to incentive levels and the suspension of a pilot program three times in 2007, and some of the reductions in incentive levels were implemented in a timely manner in late 2007 rather than waiting until January 2008. The ECMB and the Distribution Utilities, as part of monitoring 2008 programs and early steps in planning for 2009, are currently reviewing incentive levels and other program expenditures. Additional revisions, including reductions in some incentive levels, are likely during 2008.

The Department should continue these good practices by directing the Distribution Utilities to continue the ramp up of the C&LM programs, while continuing to review incentive levels and other expenditures, and make adjustments as appropriate to ensure the effectiveness and cost-efficiency of the programs, with input from and review by the ECMB.

3. The significant budget limitations in the Draft Decision would lead to customer dissatisfaction, poisoning of the market and vendor/partner relationships, and a loss or reversal of momentum.

The C&LM programs are in a vulnerable period with escalating customer demand and expanding programs and strategies, while being severely limited by budget constraints. Connecticut consumers and businesses may lose some opportunities to reduce their energy costs unless an increased financial commitment to the C&LM programs is made. Without increased C&LM funding, some programs will have to be suspended or curtailed in 2008, and other programs may have to implement waiting lists. Customers who are trying to do the right thing for themselves and for Connecticut will become discouraged and dissatisfied, and opportunities for energy and demand savings will be foregone.

In addition, the market for vendors, contractors, and partners in the C&LM programs will be disrupted, leading to a loss of vendors/partners and a loss of interest in doing business in Connecticut – similar to what happened after the C&LM program suspensions in 2003.

Any such dampening of customer interest and poisoning of the vendor/partner market would take years to overcome, as it did after the C&LM program suspensions in 2003. Not only would the C&LM programs and Connecticut policy makers lose good will, they would lose the strong momentum that has resulted from the ramp up to date, and likely reverse that momentum.

4. If the Department limits C&LM funding in the manner proposed in the Draft Decision, the Department should take several actions in parallel.

If the Department limits C&LM funding as proposed in the Draft Decision, the following actions should also be taken (which would need to be implemented through the Final Decision):

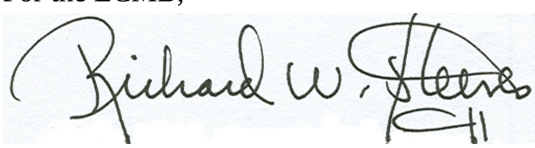
- The Department's Marketing Campaign (funded at $5 million) should be suspended or significantly curtailed. It does not make sense to conduct outreach and marketing to customers when the C&LM programs cannot respond fully to current customer demand, much less to the increased demand that would result from the Marketing Campaign.
- A portion of the funding for the Department's Marketing Campaign should be allocated to address and respond to complaints and questions from dissatisfied customers and vendors.
- Other educational and outreach expenditures should be reduced or eliminated. The ECMB views direct energy and demand savings for customers to be a higher priority for funding than general education and outreach. For example, funding for the Institute for Sustainable Energy (ISE) should be reduced (not increased), funding for other education efforts should be reduced or eliminated, and the eeSmarts evaluation should be deferred.
- Additional vendors should not be added to the Small Business program.
- Integration of the electric and gas programs may have to be delayed or deferred, as the gas programs rely on the electric programs for a substantial portion of program delivery and integration.
- The Department should consider reallocating a portion of Electric Efficiency Partners (EEP) funding to support peak demand reducing measures that would otherwise be funded through the C&LM programs. The measures should be delivered through the C&LM programs but funded with EEP monies.

5. Any increase in C&LM funding for the Institute for Sustainable Energy (ISE) and/or any significant change in ISE tasks should be reviewed by the ECMB as part of the Roadmap process.

The Department and ECMB have developed and implemented a Roadmap process for the consideration and review of proposals for C&LM funding. Any proposal to increase C&LM funding for ISE and/or modify ISE tasks should be reviewed consistent with the Roadmap process. As part of the 2008 planning process the ECMB considered the tasks and funding for the ISE and provided the recommendations set forth in the 2008 Plan (including an increase in total C&LM funding for ISE). However, the ECMB did not review the proposal described in the Draft Decision because such proposal was not submitted to the ECMB for review.

Thank you for the opportunity to submit these comments regarding the Draft Decision, and for the Department's support of the C&LM programs.

For the ECMB,



Richard W. Steeves
Chairman

CEAB
Connecticut Energy Advisory Board
WWW.CTENERGY.ORG

May 13, 2008

Donald Downes
Chairman
Department of Public Utility Control
10 Franklin Square
New Britain, CT 06051

Re: CEAB Recommendation on the 2008-2009 C&LM Program Funding

In response to the Energy Conservation Management Board's (ECMB's) letter, and request for consideration by The Connecticut Energy Advisory Board (CEAB) of the 2008-2009 Conservation and Load Management (CL&M) funding increases, the CEAB offers the following response. The CEAB is committed to working with the utilities to develop the first integrated resource plan (IRP" or "Plan") for the State of Connecticut. Under the current schedule, the CEAB anticipates the submission of a modified plan to the Department of Public Utilities (DPUC) on August 1, 2008. The CEAB continues to unanimously support the development of a fully integrated resource plan. This integrated approach, which will result in a subsequent procurement plan, is supported by the relationships between the utilities' energy procurement, requirements for efficiency and conservation programs, and compliance with environmental and renewable standards.

Based on CEAB's initial review of the DSM portions of the Plan and the DSM Focus Solution, the CEAB generally recommends that the DPUC approve the ramp up of the C&LM programs, particularly energy efficiency programs, beginning as soon as possible in 2008, as part of the overall effort to acquire all cost-effective energy efficiency and demand reduction resources, as required by PA 07-242. Such approval is consistent with the very strong customer interest and success of these programs.

The CEAB is not recommending any specific increases in C&LM funding for distributed generation or emergency generation at this time. Nor is CEAB recommending funding of all years of the DSM Focus case at this time. The CEAB will continue its review of the Plan and the DSM Focus Solution to evaluate these resources equitably with non-demand side resources. The findings and results of CEAB's review will be included in its report and modified IRP which will be submitted to the DPUC on August 1, 2008.

The CEAB appreciates the DPUC's consideration of its action. If you should have any questions, do not hesitate to contact me at

Sincerely,

John Mengacci, Chair
Connecticut Energy Advisory Board

CONNECTICUT ENERGY EFFICIENCY FUND

www.CTSavesEnergy.org

February 25, 2008

Louise E. Rickard
Acting Executive Secretary
Department of Public Utility Control
10 Franklin Square
New Britain, CT 06051

Re: DPUC Review of The Connecticut Light and Power Company's and The United Illuminating Company's Conservation and Load Management Plan for the Year 2008 [07-10-03]

Dear Ms. Rickard:

On behalf of the Energy Conservation Management Board (ECMB), I would like to request that a mechanism be developed to meet the funding gap which will occur in 2008 with respect to the Conservation and Load Management (C&LM) program. In 2007, the C&LM program experienced a substantial increase (nearly 40% over budget) in the demand for efficiency services from its customers due to a combination of factors, including the high price of electricity and other fuels and the marketing efforts of the programs. The continued increase in demand for energy efficiency programs and services is a very positive development for consumers and the State. Beginning in the third quarter of 2008, efficiency program funding should be augmented by the commencement of procurement plans authorized by Public Act 07-242, which provide for the acquisition of all efficiency and demand resources that are cost-effective, reliable and feasible. It is therefore critical that the momentum of the C&LM program continue during 2008 and that disruptions in program funding, customer service and to the program delivery infrastructure such as those experienced during 2003 be avoided.

The increased C&LM program demand experienced in 2007 required total expenditures of $98.2 million which was $27.0 million over the combined Connecticut Light & Power and United Illuminating Company (the Distribution Utilities) budget. The Department allowed recovery of $12.0 million through non-by-passable FMCC charges, leaving a balance of $15.0 million which must be charged to the 2008 budget or otherwise recovered in the future. See the attached chart for details of the adverse impacts this creates for the 2008 C&LM program budget. Furthermore, since current customer demand for C&LM programs is on a similar pace to that of last year and the Department is about to embark on a statewide energy efficiency and outreach marketing campaign, it is highly likely that actual C&LM program funding requirements will be substantially higher than the amount originally contemplated in the October 2007 filing in this docket.

In order to avoid a crisis later this year and meet the ongoing high customer demand for C&LM programs, the ECMB wishes to work with the DPUC and the Distribution Utilities to develop a plan to address the budget deficit and ensure uninterrupted program delivery to customers and to provide for additional funding to meet expected customer demand. There are at least three alternatives.

1. Utilize non-bypassable FMCC funding as was done last year for some or all of the overage.
2. Defer collection of the 2007 budget deficit and any 2008 budget deficit until at least 2009.
3. Initiate additional funding as part of the Procurement Plan in the latter part of 2008.

The ECMB would be pleased to work with the Department to ensure that the C&LM programs can continue without interruption and respectfully requests that the Department address this request in this docket.

Respectfully submitted,
ENERGY CONSERVATION MANAGEMENT BOARD

Richard W. Steeves, Chairman

2008 C&LM Budgets and Funding

	CL&P	UI	Total
2008 C&LM Budget	67,878,734	18,058,931	85,937,665
2007 Carry over	10,951,610	4,038,052	14,989,662
Funds Required	78,830,344	22,096,983	100,927,327
Funds Available			
C&LM Charge	65,378,734	16,585,931	81,964,665
FCM	1,500,000	500,000	2,000,000
Class III	1,000,000	1,000,000	2,000,000
Total Available	67,878,734	18,085,931	85,964,665
Balance Needed	10,951,610	4,011,052	14,962,662

APPENDIX H

CEAB Review for Attaining Renewable Energy Targets

2008 Comprehensive Plan for the Procurement of Energy Resources

Prepared by:

The Connecticut Energy Advisory Board

Approved August 1, 2008

CEAB REVIEW OF ATTAINING RENEWABLE ENERGY TARGETS

Introduction

Within the Integrated Resource Plan (IRP), the Distribution Utilities examined the current state of Connecticut and regional energy generation development and suggested that a re-examination of the structure of the Renewable Portfolio Standard (RPS) is warranted.[153] The IRP suggested that it was "beyond the scope of this study to estimate the future renewable energy development."[154]

The IRP scenarios and resource solution cases were modeled assuming "no significant contribution of Class I resources to meet Connecticut RPS from resources physically located in Connecticut beyond the Project 100 capacity, {assuming} the full 150 megawatts of development"[155]. The three main renewables observations that were drawn from the IRP include the following:

- There was likely a significant shortfall between the total New England RPS requirements and the Renewable Energy Credits (RECs) available from qualifying renewable energy generation projects. As a result, REC prices for total energy demand were equal to the alternate compliance payment (ACP) of $55 per megawatt hour.
- The cost of RECs at $55 per megawatt hour created annual costs to the consumers of around $200 million in 2011, growing to over $350 million by 2018 in some scenarios.
- The Distribution Utilities felt that the costs incurred did not generate renewable development because ACP was used for compliance.

Several stakeholders including Connecticut Clean Energy Fund (CCEF) felt that the Distribution Utilities had not conducted a thorough analysis of the potential renewable supply to meet the Connecticut RPS. As part of the CEAB review process, a renewable Stakeholder Input Workshop was convened to further explore the issue of renewable electric power supply. The group was facilitated

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153 IRP Finding #6 and in Recommendation 3.

154 IRP, page E-5, paragraph 3.

155 IRP, Appendix E, Section IV, page E-7.

CEAB representatives and included representatives from CCEF and its consultants, Environment Northeast, Connecticut DEP, and the Distribution Utilities. The stakeholder discussions brought forth information on the Connecticut and New England renewable supply potential and RPS demand and the cost of compliance for Connecticut load serving entities LSEs.

This Appendix presents the information brought forth during the stakeholder engagement process and CEAB recommendations based upon the stakeholder discussions. The Appendix will be divided into four sections.

- Renewable Energy Demand: Shown in this section is an estimate of renewable electric power required to satisfy both Connecticut and New England RPS requirements. Because the Connecticut and other New England State RPS requirements can be satisfied by renewable electric power delivered to New England, Connecticut competes with other New England States for renewable supply. For this reason it is important to look at the total New England RPS demand.
- Renewable Energy Potential: This section includes several estimates of the potential renewable electric power supply to meet the Connecticut and New England RPS demand. The estimates are based upon resources only eligible to meet the Connecticut RPS, planned resources and theoretical potential.
- 2018 RPS Compliance: This section presents a renewable build-out and REC price estimate which would satisfy the 2018 RPS requirements. La Capra Associates' proprietary, spreadsheet-based renewable energy market model is used to estimate the REC price and renewable resource build-out.
- Policy Recommendations: This section lays out several policy recommendations resulting from the analysis of the first three sections.

The analysis in this Appendix uses the study year 2018. One result of the collaborative CEAB review process is an additional modeling run sponsored by the Distribution Utilities. The additional modeling run incorporated the key findings of the stakeholder process including the results of the renewables analysis discussed in this Appendix. Because the run uses the 2018 Current Trends DSM Focus Case assumptions, the same assumptions were also used in this analysis.

Renewable Energy Demand

In order to assess Connecticut's ability to meet its RPS requirements with renewable resources, it is necessary to estimate the renewable electric power required to satisfy the New England and Connecticut RPS. This information is used in conjunction with the estimate of potential New England renewable supply in the following section.

None of the New England states' RPS require the renewable power to be generated in state, rather each RPS only requires that the electric power be delivered to New England. For example, the Connecticut RPS could be satisfied by renewable electric power generated in Vermont.

Connecticut Renewable Portfolio Standard

The Connecticut RPS requires that a percentage of electricity sold to retail customers come from renewable sources. It is the responsibility of the load serving entities (LSEs) to meet these requirements. The renewable electric energy does not have to be generated in Connecticut, but it must be delivered to ISO New England. LSEs can satisfy Connecticut's RPS requirements by purchasing Renewable Energy Certificates (RECs) alone or bundled with the energy associated with eligible renewable energy. If there is insufficient supply or the cost of RECs are too high, LSEs can make Alternative Compliance Payments (ACP) to the state instead. The ACP in Connecticut is $55 per megawatt hour.

The Connecticut RPS has three separate classes of renewable resources, each with their own requirements:

- Class I: Wind, Solar Thermal, Photovoltaic, Wave, Tidal, Ocean Thermal, Landfill Gas, Low-emission Sustainable Biomass, Fuel Cells and certain Small (less than 5 megawatts) Hydroelectric.
- Class II: Other Biomass, Small Hydroelectric, Municipal Solid Waste (MSW).
- Class III: Energy Efficiency Measures (instituted after January 1, 2006), Combined Heat and Power (CHP) and Waste Heat Recovery Systems.

The Connecticut RPS requirements for each class of resources are shown in Table 1. The RPS requires twenty percent of retail sales to be from Class I resources by 2020.

Table 1: Connecticut RPS Requirements

Year	*Class I*	*Class II*	*Class III*
2007	3.5%	3.0%	1.0%
2008	5.0%	3.0%	2.0%
2009	6.0%	3.0%	3.0%
2010	7.0%	3.0%	4.0%
2011	8.0%	3.0%	4.0%
2012	9.0%	3.0%	4.0%
2013	10.0%	3.0%	4.0%
2014	11.0%	3.0%	4.0%
2015	12.5%	3.0%	4.0%
2016	14.0%	3.0%	4.0%
2017	15.5%	3.0%	4.0%
2018	17.0%	3.0%	4.0%
2019	19.5%	3.0%	4.0%
2020	20.0%	3.0%	4.0%

While the Connecticut RPS is similar to the other New England RPS requirements, there are some key differences:

- The Connecticut RPS allows facilities of any age to qualify, while the other New England states' RPS only allow facilities online after a certain date. This distinction is particularly important for existing biomass facilities which may qualify by retrofitting with emissions controls.
- Connecticut is the only state to allow energy from fuel cells using natural gas, waste heat recovery and pressure reduction.

The differences in Connecticut's RPS requirements single out a group of renewable resources in New England that only qualify for the Connecticut RPS.

New England Renewable Energy Demand

In addition to Connecticut, four other New England states have established mandatory RPS requirements and one state (Vermont) has established a voluntary goal. The eligibility requirements for each state's RPS are slightly different, but the requirements are similar enough that it is expected that each state's renewable energy credit (REC) market will converge as one regional New

England market for the study years of 2011, 2013 and 2018.[156] Because Connecticut will be a player in this regional market, it is important to assess the region wide demand.

The New England-wide renewable energy demand is driven by current state RPS targets. To assess the New England-wide demand, it was necessary to make assumptions about individual state targets. The state targets and assumptions are described below.

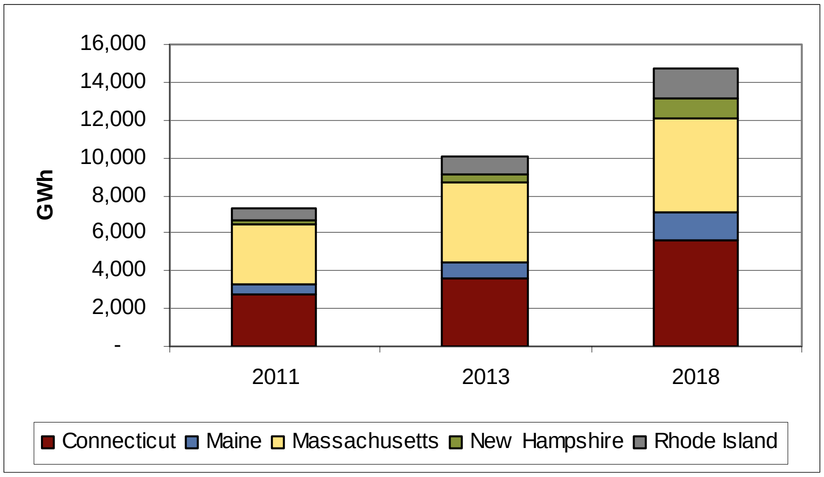
- Connecticut: Connecticut's RPS consists of Class I, Class II, and Class III resources. Only Class I targets are included, since Class II resources are generally from existing facilities and do not increase over time and Class III resources are energy efficiency measures, combined-heat and power (CHP) and other smaller-scale resources.
- Maine: Maine recently revised its RPS target to achieve 10 percent of its energy from "new" renewable generation by 2017, backed with the retirement of RECs.
- Massachusetts: Massachusetts RPS targets, by law, are to increase 1% per year after 2014. However, the continuation of the 1 percent per year increase must be reviewed by MA DOER before 2014 and can potentially be revised. For a more conservative approach, it was assumed that the target does not increase above 9 percent after 2014.[157]
- New Hampshire: New Hampshire's RPS targets consist of Class I to Class IV resources. Only Class I targets are included, since these are "new" renewable resources and other classes are for existing generation or solar. The Class I requirement increases 1 percent per year during the study period.
- Rhode Island: The Rhode Island RPS target is to achieve 16 percent renewables by 2020. Because 2 percent of the target may be met by existing renewables, it was assumed that RI will only require 14 percent new renewables by 2020.
- Vermont: Vermont recently passed an RPS goal of 25 percent renewables by 2025. However, since it is a non-mandatory goal and does not currently require the retirement of RECs to meet those goals, the state's targets are not included in the demand for RECs.

[156] We have chosen not to discuss 2030 in the renewables analysis. There is some uncertainty around future renewable programs in the region and 2030 is too far in the future to include in our analysis.

[157] Since we have completed out analysis new the Massachusetts Green Communities Act (SB 2768) has made the 1% per year increase automatic.

To determine the New England renewable demand, the legislative RPS targets were applied to state-level energy demand forecasts. Figure 1 shows the resulting New England annual renewable energy demand by state. Based on our estimates, the regional demand for renewable energy will more than double from around 7,000 gigawatt hours in 2011 to almost 15,000 gigawatt hours in 2018. If the new Massachusetts legislation (SB 2768) is incorporated into the analysis, the New England renewable demand increases by over 2,000 gigawatt hours.

Figure 1: New England Renewable Energy Demand



Renewable Energy Potential

While the Distribution Utilities' IRP states that there will not be enough renewable supply to meet the Connecticut and larger New England RPS demand, there is no estimate of New England renewable potential in the Plan. There are several methods to estimate the renewable resources that may be available to meet the Connecticut RPS. Available resources are those that could be online delivering renewable electric power to New England by 2018.

- Connecticut Only Qualifying Resources: Certain resources qualify under the Connecticut RPS, but do not qualify for other New England states' RPS. For example, Connecticut is the only state to allow existing biomass facilities to retrofit with emissions equipment to qualify as a Class 1 renewable resource.[158] Connecticut's Project 150 resources are under long term contracts through the CCEF and therefore will only qualify for the Connecticut RPS.
- Planned Projects: Developers planning renewable energy projects often apply to become qualified renewable resources for state RPS and/or apply for transmission interconnection, which are reported in the ISO New England transmission queue.
- Renewable Resource Potential: La Capra Associates has developed an estimate of renewable resource potential for New England from various sources. An estimate of developable resources in future years is based on resource potential in the region, but these resources are not necessarily tied to specific planned projects. Resources include onshore and offshore wind, biomass, landfill gas and hydroelectric.

Connecticut Only Qualifying Resources

While the qualification requirements for Connecticut Class 1 renewable resources are similar to all of the other New England states' RPS, there are certain resources that can only qualify for the Connecticut RPS:

- Project 150: Connecticut's restructuring legislation requires the State's electric distribution companies to enter into a minimum 10-year contract for not less than 150 megawatts of Class I renewable electric power by

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158 The Massachusetts Green Communities Act (SB 2768) passed in June 2008 states that Massachusetts may consider existing biomass retrofits as Class I renewable resource.

October 1, 2008. This requirement has lead to the Project 150 program, whose goal is to procure 150 megawatts of Connecticut sited renewable electric power. CCEF has conducted 2 rounds of requests for proposals for Project 150, resulting in 109.2 megawatts of Class I renewables approved by DPUC. Project 150 resources will be used to satisfy the Connecticut RPS.

- Existing Biomass: Connecticut allows existing (online before 1998) biomass facilities to retrofit with emissions controls to qualify as Class I facilities. Currently four existing biomass facilities, totaling 135 megawatts, have retrofitted with the appropriate emissions controls and are generating Class I RECs. A fifth facility, the McNeil plant in Vermont, has an approved Class 1 decision from the Connecticut DPUC. Four other facilities, totaling 67 megawatts are conducting feasibility studies on emissions retrofits. Two facilities have submitted applications, but they have not yet been approved by the DPUC. Two of the facilities already generating RECs (Livermore Falls and Stratton Energy) are burning construction and demolition waste (C&D). Public Act 07-05 extends the eligibility of C&D as a sustainable biomass fuel until the Plainfield Renewable Energy facility comes online. At that time facilities burning C&D debris will have to switch to an approved sustainable biomass fuel or lose their Class I status.[159]
- Historic Connecticut-Only Eligible Supply: Connecticut Class 1 includes biomass and landfill gas and some wind generation online before 1998. These resources do not qualify for RECs in other New England states. Sustainable Energy Advantage completed work for the CCEF and has provided an estimate of Historic Connecticut-Only Eligible Supply.
- Imports only Eligible in Connecticut: Imports from New York and Canada are eligible for Connecticut RECs as long as the renewable electric power is delivered to New England. Sustainable Energy Advantage provided an estimate of Connecticut-Only imports for the year 2012.

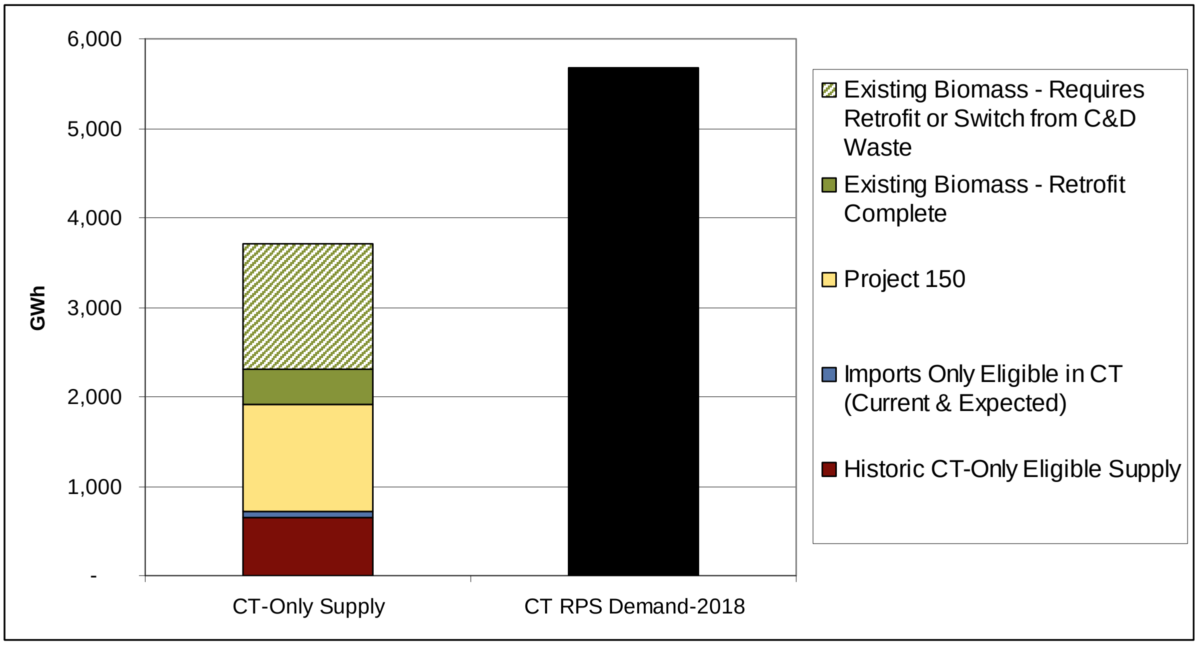
Figure 2 shows the Connecticut-Only qualified resources based on information from Sustainable Energy Advantage versus the projected 2018 Connecticut RPS demand from the IRP Current Trends DSM Focus case.[160] The biomass retrofits are divided into two categories: those facilities with completed retrofits not burning C&D waste and those facilities either requiring retrofits or a switch from C&D waste to an eligible sustainable biomass fuel. Even including the biomass facilities requiring some action to attain eligibility there is not enough

159 Sustainable Energy Advantage provided La Capra Associates information about biomass retrofits as part of SEA's work for the Connecticut Clean Energy Fund.

160 Note that the data that Sustainable Energy Advantage provided was for 2012. Because most of the Connecticut-Only resources are historic resources, Connecticut-Only resources are not likely to increase for 2018.

Connecticut-Only qualified renewable supply to meet the 2018 RPS demand. The remainder will have to come from resources outside Connecticut.

Figure 2: Connecticut 2018 RPS Demand vs. Connecticut-Only Renewable Supply



Source: Sustainable Energy Advantage and La Capra Associates

The discussion of Connecticut-only qualified resources shows that there will not be enough Connecticut-only qualified resources to satisfy the Connecticut RPS in 2018. This means that Connecticut must obtain RECs from the larger New England renewable market to meet its RPS requirements.

Planned Projects

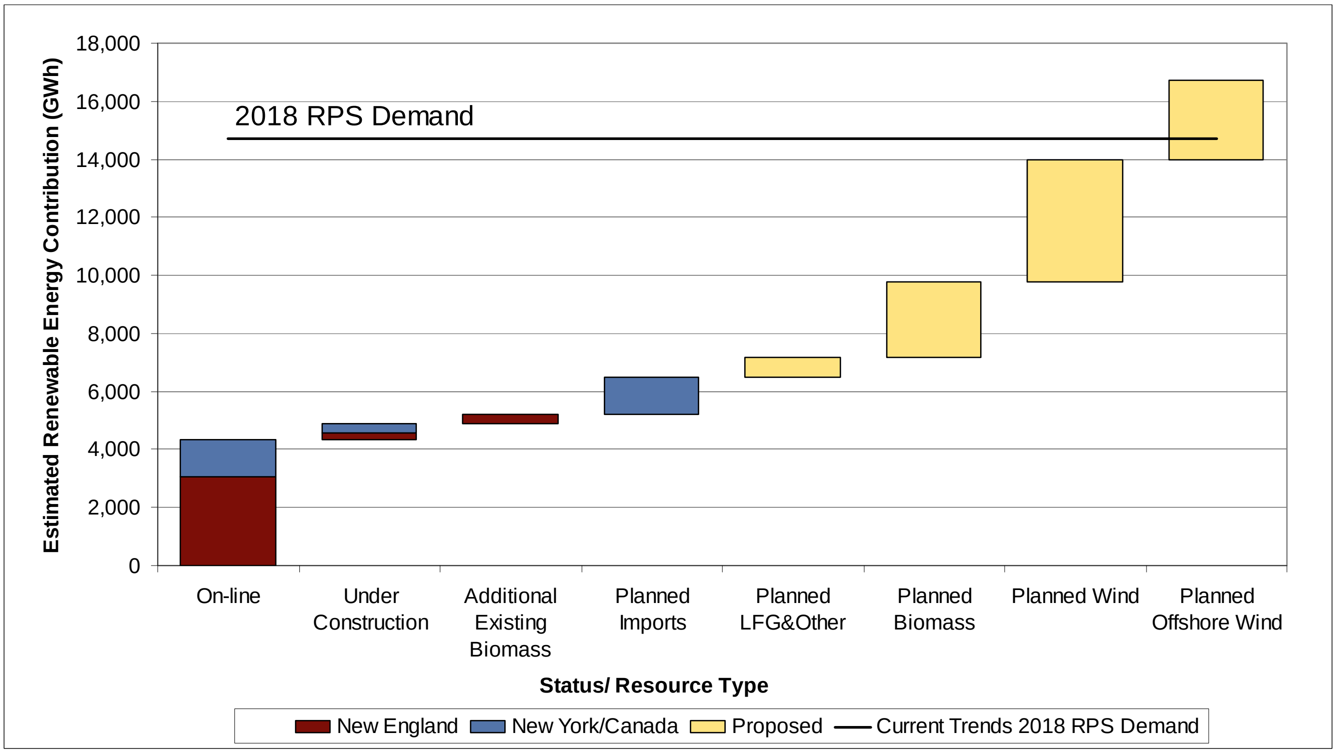
One method to examine the potential for future New England renewable resources is to look at actual projects which are currently under development. We have compiled a list of projects under development from various sources including the ISO New England transmission Queue and projects which have applied for preliminary RPS qualification determination from the New England states. Projects must apply to the ISO New England transmission Queue before they can connect to the grid, so the Queue is a good source of projects under development. While only a fraction of these projects will be built, this list is an indication of where development efforts lie. We have included some projects that have not applied to the state RPS and are not in the Queue, and it is likely that there are some projects under development missing from the project list. Also the projects in the under development list are more representative of projects likely to be on-line in the near-term (next 3 to 5 years), than in 2018.

Figure 3 shows the currently online, under construction and planned renewable projects versus the 2018 New England RPS demand. The projects are divided into the following categories:

- On-line: Online projects are ones which are already online and generating RECs.
- Under Construction: Projects under construction are in the construction phase and should be online in the near future.
- Additional Existing Biomass: There are several existing biomass facilities, which are currently conducting feasibility studies to retrofit with emissions controls. These facilities have not applied for Connecticut Class I qualification.
- Planned: Planned projects are projects currently under development, but not yet under construction. The source of information on these projects was mainly the ISO New England transmission Queue and the state RPS qualification applications, but there were several projects which we had knowledge of which had not applied to the Queue of the state RPS.

If all of projects shown in Figure 3 come online, there will be enough resources to meet the 2018 RPS requirement. While it is unlikely that all of the currently proposed projects will come online, more projects are likely to be proposed in the future. Figure 3 shows that there is the potential to meet New England RPS demand in 2018.

Figure 3: New England Planned Projects vs. New England 2018 RPS Demand*



* The Massachusetts Green Communities Act signed into law on July 2, 2008 would make the 1% per year increase in MA RPS automatic and would increase the NE 2018 RPS demand to just under 17,000 gigawatt hours.

Renewable Resource Potential

Another method of assessing the New England Renewable Supply is to look at the total resource potential in the region. Projects to be built after 2013 are most likely not in the Queue or state RPS databases yet, so the renewable resource potential may be the best way to assess renewable supply in 2018.

La Capra Associates has developed an estimate of New England renewable resource potential. The resource potential assessment considers both proposed projects in the transmission queue and the potential for future additions of renewable resources with access to the New England Market. The transmission queue helps to identify the appropriate level of build-out each year and the potential of certain resources to be developed in the future. The potential for future additions to the New England Market was derived from publicly available sources including National Renewable Energy Laboratory, Idaho National Laboratory, and Environmental Protection Agency as well as from an AWS Truewind assessment of wind potential in New England. In the potential analysis, we have attempted to estimate the amount of renewable resources which could realistically be developed by 2018.

Renewable resources in the supply curve are differentiated by state, performance characteristics and project size. The resource potential includes wind imports from New York, Quebec and New Brunswick, Canada. The Canadian imports are limited to half the current tie capacity. The resources include the following:

WIND

- Onshore (large-scale)
- Offshore (large-scale)
- Imports (New York and Canada)

BIOMASS

- Co-firing at existing generation facilities
- Retrofits – Existing biomass facilities that retrofit with emissions controls
- Repower – Old or retired facilities that repower to burn biomass fuel
- New Greenfield facilities

HYDROPOWER

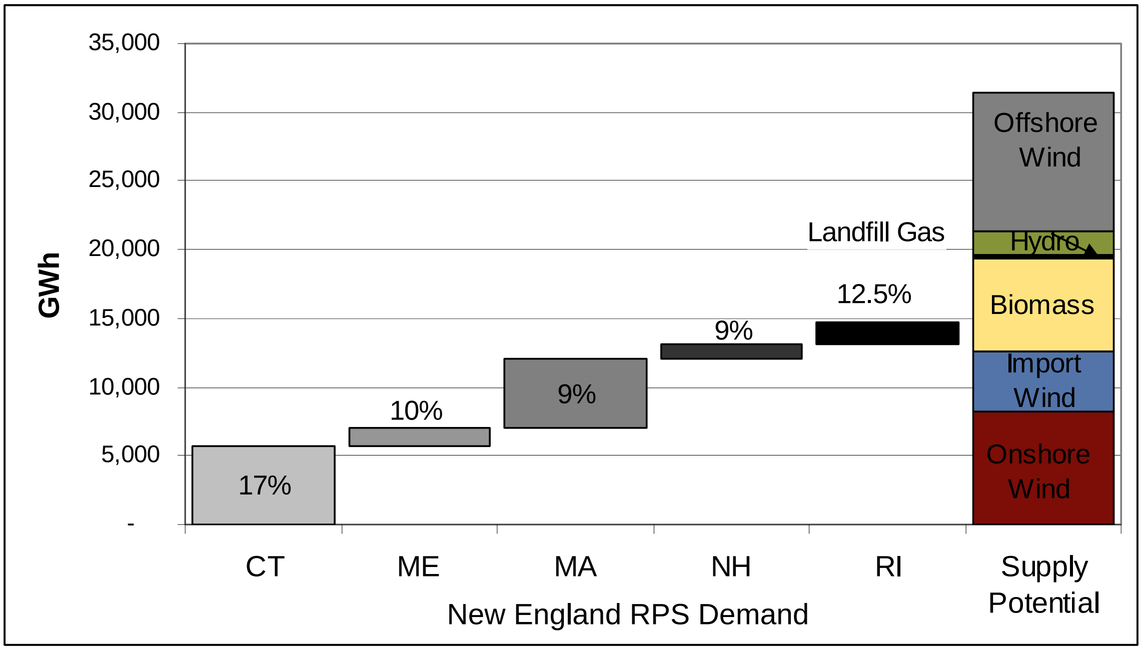
- Upgrades to increase capacity at existing facilities
- New small hydropower

LANDFILL GAS

TIDAL CURRENTS

Figure 4 shows this 2018 supply potential versus the 2018 New England RPS demand[161] as discussed in Section 0. The percentages on the state bars represent the percentage of retail sales which must come from renewable power by 2018. Together Connecticut and Massachusetts make up the majority of the renewable demand in the region. The figure shows that the estimated renewable supply potential in the region is more than double the renewable demand by 2018.

Figure 4: New England 2018 Renewable Supply Potential verses Renewable Demand



[161] Massachusetts has recently passed legislation which will increase its RPS to 20% of load by 2020. This would likely result in a Class I renewable requirement of 13%.

2018 RPS Compliance

The Distribution Utilities' IRP stated it was beyond the scope of the study to estimate future renewable energy development in New England, but did examine Connecticut's project 150 program and renewable energy projects in the ISO New England queue. Based on the ISO New England Queue and Project 150 resources the Distribution Utilities assumed that there would be insufficient supply to meet the RPS requirements. Insufficient renewable resources would result in RPS compliance by suppliers paying the $55 per megawatt hour Alternative Compliance Payment (ACP).

Given the renewable potential analysis discussed in Section 0, it is important to estimate the cost of RPS compliance with RECs rather than ACP. If the RPS is satisfied by RECs at a price lower than ACP, there could be significant savings. The renewable resource build-out required to meet the RPS requirements is also estimated. The cost of RPS compliance and renewable resource build-out are inputs to the additional model run sponsored by the Distribution Utilities and conducted by The Brattle Group. Adding renewables to the model supply mix could help reduce environmental emissions.

REC Modeling Methodology

To model future New England REC prices and renewable resource build-out, the stakeholder group reviewed an approach based on the notion that market REC prices would be set by the cost of the marginal resource. To determine the marginal renewable energy resource in each year, we developed a renewable energy supply curve and used New England renewable energy demand to "clear" the market each year.

The supply curve is comprised of our estimates of future renewable resources available in New England and their associated costs. The renewable resources are broken down into small supply chunks by cost and resource quality. For example wind resources are split into supply chunks by capacity factor, distance from transmission and project size. The costs modeled include capital costs, fixed and variable operations and maintenance costs and the costs to connect to the existing transmission system. The model does not include costs to build any backbone transmission lines in the region. The costs included in the model are based upon current developer costs and are increased with inflation to the model year. Technology improvement are assumed to reduce future costs for newer technologies (offshore wind and tidal). Current industry return on investment is also included in the cost estimate.

To develop the supply curve, resources are sorted by their required REC premium from lowest to highest. The required REC premium is the levelized cost for each resource type less the expected levelized energy, capacity and Production Tax Credit (PTC) revenues.[162] The required REC premium of the marginal resource sets the market REC price in each year.

The modeling methodology makes several key assumptions:

- Potential supply will be developed to meet demand, i.e. projects will be sited and financed if the supply potential and demand exists.
- REC prices in New England will converge even though the RPS rules for individual states are somewhat different.
- The projects will sign long term contracts for RECs.

This levelized cost approach and methodology has been used in the past to estimate long term REC prices for the New York State Energy Research and Development Authority (NYSERDA) at various times (2003–2008) for New York's RPS. The REC price estimates were very close to actual weighted average prices for contracts signed by NYSERDA with renewable energy generators.

Estimate of 2018 REC Price and Build-out

In order to calculate the incremental renewable resource supply required to meet the New England RPS in 2018, the amount of online renewable supply depicted in Figure 3 was subtracted from the New England RPS demand discussed in Section 0. Energy and capacity prices from the Distribution Utilities Current Trends DSM Focus case were used to model resource revenues. The renewable resource build-out and REC price in 2018 was estimated by determining the highest cost resource on the supply curve which was required to meet the 2018 demand. The build-out includes the market clearing resource and all resources with lower costs than the market clearing resource.

Figure 5 shows the resulting expectation for incremental renewable resource build-out. The resulting REC price was $32 per megawatt hours when assuming the PTC expires and is not renewed. This represents a $23 per megawatt hours

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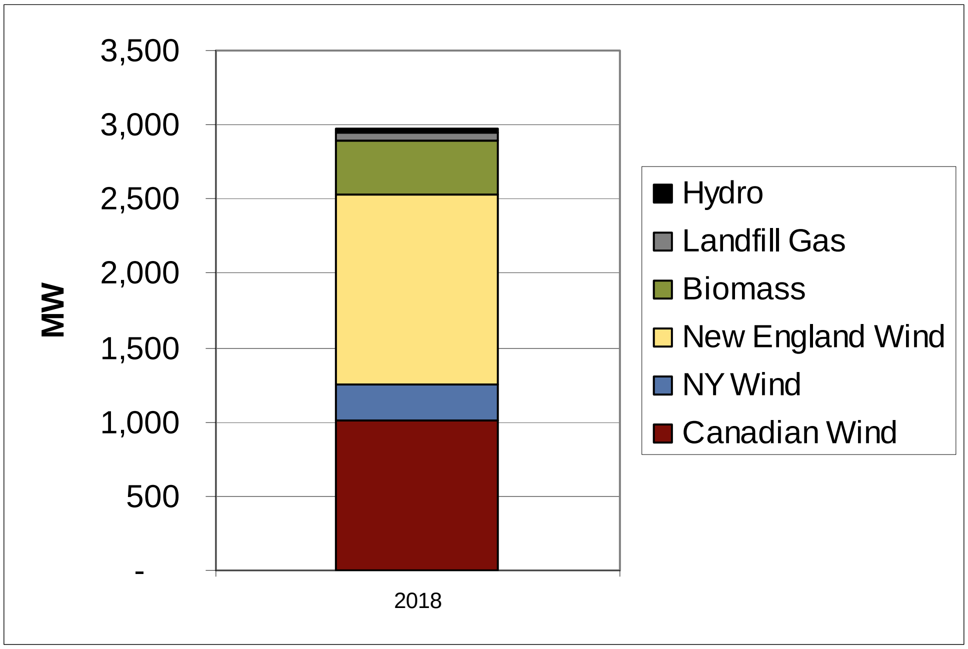
[162] The Production Tax Credit (PTC) is a two cent per kilowatt hour tax credit which applies to some of the renewable resources in the supply curve including wind, new hydroelectric and tidal. Landfill gas and new biomass receive a one cent per kilowatt hour tax credit. The PTC is currently set to expire at the end of 2008. While the PTC has expired three times since it was originally passed in 1992 and been renewed shortly after its expiration, we have modeled the resource revenues without PTC. The REC price could be even lower if the PTC or other federal government subsidy is available.

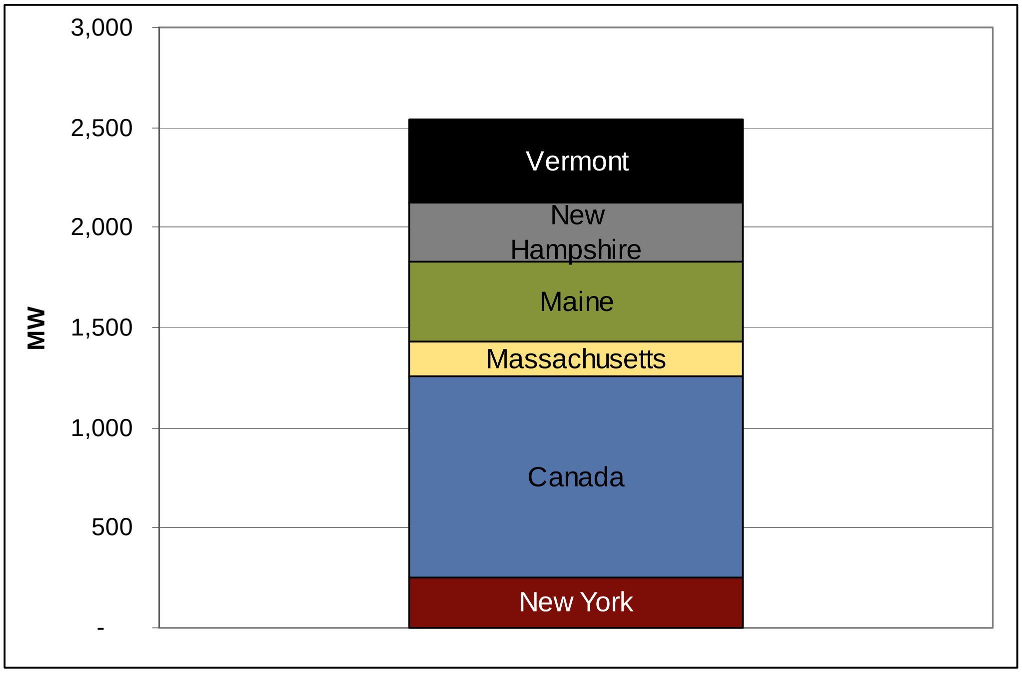
savings compared to ACP. This build-out includes over 1,700 megawatts of renewable power in New England, with almost 1,300 megawatts being wind power. In addition, wind imports from Quebec, New Brunswick and New York make up over 1,200 megawatts of the build-out.

Figure 5: 2018 Renewables Build-out



Of the almost 3,000 megawatts included in the build-out, there is 2,500 megawatts of wind power. The wind is primarily located in Northern New England or is imported into New England from Canada or New York as shown in Figure 6. The location of the wind resources may cause transmission improvements to be a necessary step in order to bring wind power from Northern New England and Canada to the load centers in Southern New England.

Figure 6: 2018 Wind Build-out by State



Observations from Analysis

Importance of Supply Demand Balance

The analysis in Section 0 shows that there is sufficient renewable potential to satisfy the New England RPS requirements through 2018. Historically, there has not been enough renewable supply in New England. This problem does not stem from inadequate renewable supply potential, but has occurred because of the challenges of siting and financing projects in the region.

New England's history of supply constraint has led to REC prices close to ACP. One key assumption of the renewable market model discussed in Section 0 is a balance between supply and demand. The analysis estimates that the REC price in a balanced market would be $32 per megawatt hour, resulting in a 40% savings compared to ACP of $55 per megawatt hour. Therefore, when making the supply and demand balanced in the model analysis, it shows that the magnitude of savings is quite substantial.

Long Term Contracts

Long term contracts help projects secure financing and therefore promote renewable resource development. Sufficient resource development would help create a balance of supply and demand in the market place and should result in a REC price below ACP.

Beginning this year, Connecticut's electric distribution companies (EDCs) have authority to procure RECs from Class I, Class II and Class III sources through long-term contracting mechanisms. The electric distribution companies must use any RECs obtained pursuant to such long term contracts to meet their standard service and supplier of last resort renewable portfolio standard requirements.[163]

Given the important benefit of long term contracts and the recent authority given to EDCs to procure long term contracts, ,the following actions should be taken:

1. A significant portion of the uncommitted standard service REC requirements for 2014 and beyond should be obtained through long term contracts to lower the overall cost of RPS and to assure the full development of the needed renewable resources.
2. The DPUC should direct the EDCs, along with the CCEF, to create a pilot contract solicitation to allow the DPUC to evaluate the potential contracting for bundled RECs, energy and capacity, in order to further reduce REC costs.

It should be noted that other New England states are seeing the benefits of entering long term contracts for renewables. In the Massachusetts Green Communities Act,[164] signed into law on July 2, 2008, requires Massachusetts EDCs to sign long term contracts for not more than 3 percent of the electric demand in the state. One conclusion that could be drawn from this piece of legislation is that it may require that the contracted renewable power be produced in Massachusetts. This rule is more similar to Connecticut's Project 150 than the recent long term REC docket in Connecticut.

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163 See, Conn. Gen. Stat. Sec. 16-245a(g) and DPUC Draft Decision in Docket No. 07-06-61 DPUC Examination of Electric Distribution Company Contracts For Renewable Energy Certificates dated June 30, 2008. In a Draft Decision pertaining to long-term REC contracts, "[T]the Department has set forth some specific terms and some general guidelines for REC contract provisions. The Department allows, but does not require the electric distribution companies to procure REC contracts for new Class I resources. The Department will authorize a maximum of 0.4 mills per kilowatt hours as incentive compensation for long-term renewable energy certificates contracts. Any renewable energy certificates obtained pursuant to long-term contracts shall be used to meet their standard service and supplier of last resort renewable portfolio standard requirements. All costs associated with the long term renewable energy certificates contracts will be recovered through generation service charge rates." See, Draft Decision, Docket No. 07-06-61 DPUC Examination of Electric Distribution Company Contracts For Renewable Energy Certificates dated June 30, 2008.

164 MA Green Communities Act (SB 2768), passed on June 26, 2008, signed on July 2, 2008

Northern New England and Canadian Renewables

The estimated renewables build-out in 2018 showed that a significant amount of wind from Northern New England and Canada was required to satisfy the New England RPS requirements. Transmission improvements will be necessary to bring large amounts of renewable energy from Northern to Southern New England. ISO New England is currently studying transmission needs for NNE build-out or Imports. Connecticut should consider supporting transmission to bring northern (Maine, New Hampshire, Vermont or Canadian) renewables to Southern New England. There is limited renewable resource potential in Connecticut and other Southern New England States, which required these states to rely on Northern resources for renewable generation.

APPENDIX I

CEAB Review of Connecticut Generation

2008 Comprehensive Plan for the
Procurement of Energy Resources

Prepared by:
The Connecticut Energy Advisory Board

CEAB
Connecticut Energy Advisory Board

Approved August 1, 2008

CEAB REVIEW OF CONNECTICUT GENERATION IN THE IRP REPORT

Introduction

On January 1, 2008, United Illuminating and Connecticut Light & Power jointly filed an Integrated Resource Plan (IRP) for Connecticut. This plan was prepared under the direction of and on the utilities' behalf by The Brattle Group. The legislation provided that the Distribution Utilities' plan be reviewed and potentially modified by the CEAB. The CEAB subsequently examined several issues.

This appendix:

- Reviews issues regarding Connecticut's existing generation.
- Provides an overview of how the potential retirements of existing older generation in Connecticut was evaluated in the IRP.
- Summarizes the input and concerns expressed by interested parties regarding the reliance on aging generation, especially given their contribution to Connecticut's overall emissions concerns. This input led to CEAB requesting the supplemental analysis, observations, and conclusions.

CT Generation in the 2008 IRP Report

The IRP is a very comprehensive document including extensive discussion of assumptions and results. The recognition of the costs associated with operating older generation units in Connecticut in the analysis is documented in Appendix A of the IRP.

The IRP was developed utilizing a scenario planning approach, where different resource options in the future were analyzed with four very distinct plausible future sets of conditions (scenarios) regarding fuel prices, the electric peak load and energy requirements, the cost of and potential concerns regarding the siting of new generation, and the prices for CO_2 allowances given the potential for large differences between proposed carbon regulation legislations. These four scenarios are called Current Trends, Strict Climate Policy, High Fuel/High

Growth, and Low Stress.[165] The analysis included modeling the years 2011, 2013, 2018, and 2030, in order to provide the 3, 5, and 10 year information as required by the legislation.

Each of the four scenarios tested the impact of more DSM by incorporating the DSM Focus resource solution discussed below.

Analysis of Connecticut Generation

The scenario analysis used to develop cost, environmental, and other metrics developed four resource solutions for future capacity additions: conventional gas, nuclear, coal, and DSM Focus. The first three incorporated the Reference Case DSM costs and impacts. In the DSM Focus resource solution, any capacity needed in New England was modeled using conventional gas generating capacity.

Resource Requirements

Section II-C of the IRP discusses how the study analyzed the need for additional resources. The need for new resources can result from several comparisons of requirements to the inventory of current and committed resources.

The IRP first establishes that whether ISO New England requires any additional resources over the study period. The analysis assumed that over 1,400 megawatts of new generation or upgrades, are planned and expected to be in service by 2011 and more than 700 megawatts of peak demand savings by 2011.[166] Generally, the IRP demonstrates that in all the scenarios, there is surplus in 2011, basically balanced in 2013; and that by 2018, there is a need for additional New England resources, supply, or demand management.

Continued Operation of Existing Generation

An immediate resource question that the IRP had to address is whether all the existing generation will continue to operate over the next ten years. The IRP approached this by performing an economic analysis to determine whether it is likely that the capacity will retire.[167] The analysis looked at all the costs that are incurred to keep the generation facilities operating and compared them to the revenue a generation facility would receive from ISO New England markets. The IRP assumed it was appropriate to apply this test to the units in Connecticut that were at one time classified as Reliability Must Run (RMR), that is, needed for system reliability.

165 These scenarios are fully described in the IRP, Appendix B, Section IIB, page 5.

166 The results of this analysis are shown in Table 2.2 on page 12 of the IRP.

167 The IRP describes the analysis within Appendix A Section II.

The estimates of the O&M costs for the units in questions were shown in Table A-3 of the IRP, which is reproduced below. The IRP results for this retirement analysis was described on pages A-6 and A-7, and is reproduced here:

"A unit's entire FOM cost should not be considered avoidable through retirement because there are costs of retiring a plant and maintaining or remediating a site, if applicable. Furthermore, one or two years with low revenues would probably not induce retirement, given the cost of giving up an option to capture significant value in a good year. Hence, we did not consider retiring units unless revenues fell several dollars per kW-month short of covering their fixed O&M costs. With capacity prices in the $3-4/kw-month range in all scenarios for 2013 through 2018 (see Table A.7), all units passed the preliminary screen except for Norwalk Harbor 1 & 2. However, we understand that those units or other new resource may be necessary for reliability in the Norwalk area in order to protect against contingencies when one of the new 345 kV transmission lines into Norwalk is out of service. Therefore, we assumed that Norwalk Harbor 1 & 2 would stay online in spite of our screening analysis."

Table A.3 of the IRP: Fixed O&M Costs of RMR Units in Connecticut

Station/Unit	Summer Capacity (MW)	Fixed O&M ($)	FOM ($/kW-Mo)
NRG -- Middletown 2-4, and 10	770	41,071,316	4.44
NRG -- Montville 5, 6, 10, and 11	494	25,608,334	4.32
Milford 1 and 2	492	21,315,292	3.61
PSEG -- New Haven Harbor	448	16,996,000	3.16
PSEG -- Bridgeport Harbor 2	130	6,009,000	3.84
NRG -- Norwalk Harbor 1 and 2	330	29,497,659	7.45

Source: Company RMR Filings to ISO-NE

Two Ways to Look At Generation Cost – Market and Cost-of-Service Regimes

The IRP looked at the cost impacts to Connecticut ratepayers of the different scenarios; resource solutions were evaluated under two variations as to how the resource output is purchased. The Market Regime (as it is called) modeled the cost impacts as if Standard Service power is procured at the market, primarily a function of the LMPs of the energy market and the clearing prices for capacity of the FCM. The Market Regime is essentially how the Connecticut ratepayer secure power today. The Cost-of-Service Regime is modeled with that all the resources in Connecticut having their output for energy and capacity procured at cost by Connecticut ratepayers.

Findings and Recommendations

The IRP developed many outputs referred to as metrics to compare the relative benefits and costs of the different resource solutions. The results are discussed and shown in Section III of the IRP; detailed output information and documentation is provided in Appendix H. The IRP findings and conclusions are contained in Appendix B of this Procurement Plan. The section below, "IRP Findings and Recommendations Pertaining to Connecticut Generation", details the most relevant assessments.

CEAB notes that while the findings are directly related to the resulting metrics provided in Section III of the IRP; the conclusion to recommend long-term cost of service contracting is not as obvious. The IRP established that additional resources over the ten year study period are needed. The IRP with the market regime and cost-of-service regime comparisons does not demonstrate the benefits, costs, and risks of long term generation contracts at cost-of-service prices. It is hard to isolate long term contract effects in the IRP analysis.

IRP Findings and Recommendation Pertaining to Connecticut Generation

1. Regional Resource Adequacy Needs are Satisfied for the Next Several Years

After taking into account planned generation additions, recent and planned transmission projects, and demand-side measures that are planned or underway, and assuming no retirements, new electricity resources will not be needed to attain reliability targets for several years in Connecticut or elsewhere in New England. Under most plausible futures, New England as a whole will need additional resources beyond the next five years. As part of the overall New England market, Connecticut will share in this resource need, but additional resources need not be located within Connecticut in this time frame.

2. Connecticut's Local Resource Adequacy Needs are Satisfied for the Foreseeable Future

Planned generation capacity additions, transmission enhancements and demand-side measures mean that Connecticut will satisfy its Local Sourcing Requirement (LSR) for many years, perhaps decades, under the scenarios examined in this report. This is partially due to the projected addition of DSM and generating capacity, including 279 megawatts of quick start capacity needed to satisfy the Connecticut Local Forward Reserve Market (LFRM) requirements. However, this analysis assumes no significant retirement of generating capacity in Connecticut, although some of the older oil-fired units are projected to earn sub-normal returns and/or experience difficulties covering their fixed O&M costs over the longer term; potentially resulting in retirement or reapplication for "reliability-must-run" status. Also, no significant congestion price differentials are forecast between Connecticut and the rest of New England. Transmission enhancements already under construction and planned generation will resolve the significant bottlenecks and limited local supply resources that have affected Southwest Connecticut in the past.

10. Market Regime vs. Cost-of-Service Affects Rate Stability and May Have Future Customer Cost Implications

As constructed/assumed, the hypothetical "Cost-of-Service" regime has substantially lower costs than the "Market" regime, across all scenarios and strategies studied; however, these results indicate more analysis is warranted. The overall cost levels used in the analysis may not offer a realistic comparison on a regional market basis, because it is probably not possible to put all generating assets back under cost of service regulation at historic embedded costs. The actual purchase costs for existing generation would not likely be at the levels assumed in the Cost of Service results because the fixed costs for some of the existing assets assumed in the Cost of Service analysis are below current market values. However, output from new construction owned outright and output from new assets acquired via long-term contracts could potentially be obtained at prices reflecting Cost of Service, but this was not evaluated in this study. The results also show that the range of costs is much smaller under Cost of Service. The potential range of total supply costs is generally lower than the range of market prices. This is primarily because under a market regime, the market price for all power is determined by the last unit of supply. In very simple terms, if the cost of the last unit of supply increases by 10%, then under a market regime customer costs increase by 10%. But the total cost of generating power from all sources varies by much less than 10% (many of these costs are fixed and don't vary with the last unit's costs). If customers were to be supplied under a regime more closely reflecting actual generating costs, customer costs will increase by less than 10%. Even if only some assets are procured on a cost basis, this will reduce customers' exposure to uncertain and volatile prices. As discussed below, it may be possible to procure power from some existing and/or new resources in ways that mimic cost-based pricing and allow customers to enjoy some cost-stabilization.

It is crucial to note here that while it is possible to reduce the uncertainty and volatility of customers' costs, it may not be possible to substantially reduce the expected level of costs in the near- or mid-term. However, long-term contracts for the output of new or existing assets can reduce uncertainty which can lower costs. Such questions of procurement and risk management are beyond the scope of this resource planning effort, but are likely to be important issues to consider in addressing the concerns of Connecticut customers.

Recommendation 2: 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.

At the present time, the Distribution Utilities are constrained to enter into contracts with third-party suppliers with durations not to exceed three years to satisfy standard offer service obligations, which ensures that customers are exposed to power supply prices driven by short-term market prices. Our finding that customer costs would be more stable under a hypothetical cost-of-service regime suggests that supply arrangements incorporating cost-of-service principles could help to stabilize customer rates and potentially, under certain conditions, lower prices for the customer. This could be achieved by providing the Distribution Utilities 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, including baseload generation that is not dependent on natural gas. By reducing the extent to which utilities are forced to procure power through short-term contracts driven by regional spot market prices, such alternative procurement options can reduce customers' exposure to uncertain and potentially high gas prices, and may provide to customers some benefits of a diverse fuel mix. Addressing these issues may involve the use of procurement strategies and risk management tools (such as fuel hedging strategies to complement electricity procurement) that go beyond what can be done in a resource planning context. In addition, strategies such as these should be coupled explicitly with the assurance of recovery of supply costs associated with approved long-term power procurement contracts.

Public Comment and Stakeholder Input

The CEAB solicited public comment in several forums as part of its review. The CEAB review process had planned for taking written comments from the public followed by a public hearing. In addition, based on those public comments and the preliminary assessment by CEAB, additional input was gathered utilizing a dozen workshops covering six topics. The analysis and assumptions regarding existing Connecticut generation was one of those topics.

Public Comments

Public sentiment showed concern that the IRP did not accurately anticipate change to existing generation in Connecticut. There were concerns expressed by the generation community that it is far from certain that the older generating units in Connecticut will be operating in ten years. A summary of these concerns is reproduced below:

Summary Of Public Comment On The Distribution Utilities' Assumption Concerning In-State Generator Retirements

Several commentators took strong exception to the Plan's assumption that there will be no generator retirement in Connecticut given the vintage of Connecticut's generating units, expected environmental regulations, and the conclusion of reliability must run agreements in 2010.33 NRG, for example, said the Plan's retirement assumption is implausible and that the Plan must take into account the potential of older generating units to require environmental or other upgrades to avoid retirement, and evaluate whether refurbishment of the units would be a viable resource solution to achieve environmental standards and minimize ratepayer costs. No commentators suggested that the IRP's retirement assumptions were reasonable.

CEAB Initial Critique

The Distribution Utilities have provided an assessment of energy and capacity requirements for each of the time horizons specified in the requirement.

The IRP does not include any assessment addressing the potential attrition of existing generation in Connecticut. The planning assessments did not consider environmental issues associated with existing generation other than compliance with the Regional Greenhouse Gas Initiative. The Distribution Utilities screening of going-forward costs assumed no need for investment for environmental controls or other costs or operating restrictions resulting from more stringent environmental standards. In consultation with generator owners, the IRP will benefit from better information on the risk of loss of existing in-state generation and associated issues. The Distribution Utilities' willingness to perform additional modeling runs will enable this work to be accomplished most efficiently.

The absence of an assessment under possible retirement scenarios is a limitation of this study. The large number of aging power plants in Connecticut has been an issue raised by ISO New England in its regional system planning process. Similarly, the CSC assessments of Connecticut's loads and resources have reported the magnitude of aging capacity. An excerpt from the CEAB's assessment of this issue is reproduced here:

Excerpt from the CEAB Preliminary Assessment or the Integrated Resource Plan for Connecticut January 28, 2008[168]

Section II A:
The Energy And Capacity Requirements Of Customers For The Next Three, Five And Ten Years

Description of the Requirement:

This assessment is a standard utility planning analysis including load forecasting and installed capacity requirements assessments.

Energy and capacity requirements, in total, are determined with load forecasting techniques that estimate the growth in electricity demand over time. This typically includes forecast of energy requirements by month/season/year and of peak demand (i.e., the highest hourly load in each month/season/year). ISO New England now does this form of assessment to set the installed capacity requirements for the Forward Capacity Market three years in advance. The Connecticut Siting Council (CSC) also collects and publishes such forecasts annually.

The assessment of the requirements for new or additional capacity and energy to meet requirements that cannot be met without new supplies is also typically conducted in this assessment. In this instance, a forecast of energy and capacity that will be available from existing sources is compared to the load forecast to determine any gaps between supply and demand over time.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities have included an assessment of the energy and capacity requirements for the 3, 5, and 10 year periods and for the year 2030 in Section II C of the Distribution Utilities' IRP. This assessment uses ISO-New England load forecasts to assess the needs requirements in the State, providing projections of total requirements and the need for new supplies for four scenarios. The requirements that the Distribution Utilities addressed include the Forward Capacity Market Installed Capacity Requirements and the Connecticut Local Sourcing Requirements, as well as consideration of new supplies under development now to meet the Forward Capacity Requirements or the Locational Forward Reserve market requirements.

From the assessment conducted, the Distribution Utilities conclude that no new generation additions are required in Connecticut over the next decade to meet the Local Sourcing Requirements of the ISO New England Forward Capacity Market, assuming no retirements of existing generation. (Companies' IRP, page 40)

Section IV C:
The Optimization Of The Use Of Generation Sites And Generation Portfolio Existing Within The State

Description of the Requirement:

[168] See Appendix C for the entire text of this assessment.

This provision is included to assure that the planning process consider the future use of the existing generation facilities in Connecticut and the sites that have been or could be used for generation projects.

Summary of the Treatment of the Requirement in the Distribution Utilities' IRP:

The Distribution Utilities conducted a screening analysis of the Connecticut generation units that have operated under a Reliability Must Run agreement with ISO-New England to assess the potential for retirement of these units. (Companies' IRP, Appendix A, page A-6). Using an analysis that considers the going-forward avoidable fixed O&M, the Distribution Utilities concluded that all of this generation would remain operational throughout the planning period. Based on this assessment, all of the need assessments and market analysis conducted by the Distribution Utilities for the IRP assumed no retirements of existing generation.

The Distribution Utilities' IRP does not address the utilization of generation sites and state that their IRP is "not a siting analysis for new generation capacity". (Companies' IRP, page 48).

The Distribution Utilities included an assessment of the differences between market pricing and an assumed cost-of-service pricing for existing generation. This assessment indicated a substantial differential in cost and lead the Distribution Utilities to include a recommendation to explore alternative procurement approaches to improve the cost of supply to customers. (Companies' IRP, Recommendation 2, page 46).

The Distribution Utilities' IRP does not include any assessment addressing the potential attrition of existing generation in Connecticut. As noted in Section II D above, the planning assessments did not consider environmental issues associated with existing generation other than compliance with the Regional Greenhouse Gas Initiative. The Distribution Utilities screening on going-forward costs assumed no need for investment for environmental controls or other costs or operating restrictions resulting from more stringent environmental standards.

The absence of an assessment of the plan under possible retirement scenarios is a limitation of this study. The large number of aging power plants in Connecticut has been an issue raised by ISO New England in its regional system planning process. Similarly, the CSC assessments of Connecticut's loads and resources have reported the magnitude of aging capacity.

Stakeholder Input Workshops

The CEAB held three generation focused Stakeholder Input Workshops sponsored collaboratively by CEAB and the Distribution Utilities. The stakeholders participating were the DEP, Environment Northeast, AARP, NRG, PSEG, Competitive Power Ventures, NEPGA, and First Light Power. Generators like NRG, First Light Power, and NEPGA were particularly active in the stakeholder group.

There were several issues discussed during the Stakeholder Input Workshop. The generators were concerned with the Distribution Utilities conclusion that all Connecticut generation units would continue to operate throughout the planning period. The generators believed that the IRP has not included all the costs and risks of continued operation in the going-forward cost analysis. They believed that if the proper costs and risks were included in the analysis, some facilities would be likely to retire before 2018. The generators also stated that they were evaluating options to repower or retire several Connecticut facilities.

Another issue discussed by the group was the changing regulatory environment in the state. The Distribution Utilities' analysis had not incorporated the DEP's future emissions goals[169] and therefore generating units were not assumed to invest in upgrades to meet tightening emissions regulations. The omission of environmental upgrade costs also led to understated going-forward cost assumptions. The DEP stated that without retiring, repowering, or retrofitting some portion of the existing generation units in the state, it will be impossible to meet their targets for emissions levels.

Much discussion in the Stakeholder Input Workshops was devoted to determining the proper going-forward cost and emission retrofit costs to include in the analysis. The workshops were valuable because they initiated dialogue between the DEP, the utilities, and Connecticut generation owners on continued operation costs. The CEAB attempted secure support of the generation companies to provide:

- Some sort of a primer on the way a generating company looks at continued operation of older generation from cost and risk perspectives.
- Generic or average cost estimates for these categories by generating unit technology and fuel relevant to Connecticut existing units.
- Individual owners' sponsored best available public information to be used with specific units in economic analysis.
- Support in applying the correct 'potential' retrofit projects (that is, emissions reduction technologies) for the each unit. The scenarios anticipate the tightening regulations on allowable emissions rates.

From this discussion, NRG was able to provide technical expertise in identifying likely environmental compliance retrofit projects and an estimate of retrofit costs. Beyond emissions retrofit costs, confidentiality concerns prevented the generating companies from sharing detailed going-forward cost estimates. NEPGA did provide some information on required minimum revenue for generation facilities to continue to operate (shown in Figure I-1 below). CEAB and the Distribution Utilities elected not to use this information. The generation community was unable to demonstrate the reasons why the going-forward cost analysis was inappropriate other than for general discussion. The Supplemental Analysis was going to capture the environmental retrofit investments discussed in the prior section.

169 Discussed in detail in Appendix J.

Figure I-1. Minimum Required Revenue for Continued Unit Operation

NEPGA MEMBERS INPUT TO CONNECTICUT IRP ON REQUIRED MINIMUM REVENUE FOR CONTINUED UNIT OPERATION

				2010-2011	2011-2012	2012-2013
			CONE	$7.50	$6.00	$4.92
				Auction I	**Auction II**	**Auction III**
				$4.50	$3.60	$2.95
Asset Name	**Units Type**	**MW**	**Cost of Service $/kW-month**	Floor Price as % of Cost of Service	Floor Price as % of Cost of Service	Floor Price as % of Cost of Service
Bridgeport Energy	combined cycle	442	9.52	47%	38%	31%
Milford 1 & 2	combined cycle	489	12.36	36%	29%	24%
NRG Devon 11-14	combustion turbines	119	13.79	33%	26%	21%
NRG Middletown 2-4, 10	fossil steam, CT (10)	770	5.37	84%	67%	55%
NRG Montville 5,6,10 & 11	fossil steam, CT (10, 11)	494	4.84	93%	74%	61%
NRG Norwalk Harbor 1 & 2	fossil steam	330	9.51	47%	38%	31%
PPL Wallingford 2-5	combustion turbines	169	10.85	41%	33%	27%
PSEG Bridgeport Harbor 2	fossil steam	130	8.98	50%	40%	33%
PSEG New Haven Harbor	fossil steam	448	6.97	65%	52%	42%
	Total MW	3,391				
		Average Rate	$9.13	49%	39%	32%

Notes:

Cost of service taken from latest RMR filings and listed in ISO-NE COO Report dated May 9, 2008

Clearing prices for Auction II and III and CONE for Auction III are projections

Environmental Regulations' Impact on Generation

Since the Distribution Utilities' analysis did not account for tighter NO_x and SO_2 regulations, the going-forward costs of older Connecticut oil/gas steam generation remained low and thus no retirements were warranted. The initial plan did not adequately consider retirements or retrofits for environmental controls and current efforts to reduce emissions, especially of pollutants such as NO_x that can dramatically impact ozone levels.

Connecticut is currently implementing a suite of emission reduction strategies targeting a wide-range of sectors in the state, including electric-generating units. Within the Stakeholder Input Workshops, the DEP discussed their need for and current efforts to implement revised emission regulations over the next ten years. These regulations would greatly affect utility class boilers fueled by coal, oil, and natural gas. These boilers would be required to cut their emission rates in half for SO_2 and NO_x. These older units possess some of the highest emissions rates of NO_x per megawatt compared to other capacity resources. These older units operate to provide operating reserves and to provide peaking capacity, primarily operating within the summer ozone period and especially during "high energy demand" days that often produce the poorest air quality measured in the State. The potential regulations would limit the amount of emissions on a per unit basis, irrespective of how little a generating unit actually produces electric power.

In order to accurately model the costs within each scenario, the analysis needs to address the investments required to meet the anticipated lower emission rate levels. The Stakeholder Process allowed the CEAB to obtain technical input from an environmental focused staff member of NRG. The types of equipment that the different Connecticut generation units needs to install was discussed in a Stakeholder meeting and subsequent calls. This is based on an outsider's level of knowledge of the generating units, not an endorsed project retrofit plan by each operator of generation. It was determined, from these estimates, that since focus was on 2018, the assumption would be made that the generating units had to invest in Selective Catalytic Reduction (SCR) equipment and Scrubbers. The cost assumptions were derived from the report Assessment of Control Technology Options for BART-Eligible Sources prepared by Northeast States for Coordinated Air Use Management in Partnership with the Mid-Atlantic/ Northeast Visibility Union May 2005 (BART report). In addition to these investments, there is incremental annual Operation and Maintenance (O&M) costs to run those facilities. Naturally, there will be a lower cost to actually run the units since they now require less NO_x and SO_2 allowance credits.

Table I-1: Cost Assumptions for Environmental Retrofit Investments[170]

Environmental Retrofit Investments Cost Assumptions		
	2008 dollars	
Unit Types		**SCR**
	Capital Costs ($/kW)	Variable O&M ($/ton)
Boiler		
Coal	$ 256	$ 2,017
Residual Oil	$ 114	$ 2,017
Distalate	$ 114	$ 2,017
Gas	$ 87	$ 2,017
CT		
Oil	$ 82	$ 1,899
Gas	$ 82	$ 1,899
		Scrubber
	Capital Cost ($/kW)	Variable O&M ($/ton)
Large Boiler (600 MW)	$ 242	$ 672
Small Boiler (200-300 MW)	$ 471	$ 672

For a larger discussion of managing emissions, please refer to Appendix J.

170 Source: Assessment of Control Technology Options for BART-Eligible Sources prepared by Northeast States for Coordinated Air Use Management in Partnership with the Mid-Atlantic/Northeast Visibility Union May 2005

Supplemental Analysis

The CEAB has drawn enough from the IRP, public input, and stakeholder process, as well as its review of the issues, to realize some enhancements to the analysis is needed. Working collaboratively with the Distribution Utilities, the Supplemental Analysis was performed.[171]

Revised Going-Forward Cost-based Retirement Analysis

The supplemental analysis included a retirement analysis to estimate retirements based upon the revised going-forward cost and emission retrofit assumptions discussed during the Stakeholder Input Workshops. In this analysis, units were assumed to invest in the control technologies if economics indicated that the generation owner would receive enough revenue to cover costs and a fair return on the incremental investment in the retrofit. This translates roughly to a criteria that generation units will invest and continue to operate if the payback period would be less than 5 years; will retire if the payback period would be over 10 years; and will retire about 50% of the megawatts if the payback period is between 5 and 10 years.

Incorporating Retirements into Supplemental Analysis

The supplemental retirement analysis showed that the assumed tighter NO_x and SO_2 regulations would result in the retirement of 1,400 megawatts of older oil/gas steam generation in Connecticut, and over 2,600 megawatts in New England. In the analysis, the retired units are assumed to be replaced by cleaner, more efficient combined cycle units. The supplemental analysis showed that approximately 2,400 megawatts of generic capacity would be required by 2018 to replace the retired units.

The Benefits – Reduced Emissions and Lower Market Prices

The supplemental analysis showed that the retirements had a positive impact on both environmental emissions and market prices. Under this scenario for 2018, the retirements and retrofits decrease total annual NO_x emissions by about 30%, summer seasonal emissions by about 35%, and emissions on the ten peak days by about 60% when compared to the DSM Focus resource scenario. Market prices are lower for the retirement scenario than the scenario that does not incorporate retirements.

171 See Appendix K for a discussion of this supplemental analysis.

Observations

The CEAB review processes described above lead to several observations regarding existing Connecticut generation.

1. Changes to environmental regulations affect the economic viability of long-term continued operation of existing older generation.

Older generating units would be required to retrofit with emissions controls to meet DEP emissions goals. This would increase the going-forward costs of the units and compromise their economic viability.

2. A significant amount of older generation in Connecticut could be taken out of service in the next ten years.

The supplemental analysis showed that 1,400 megawatts of Connecticut's oil/natural gas steam generation resources would retire when the cost of required emissions retrofits to meet future environmental regulations were included in the going-forward cost calculations.

3. The environmental retrofits of older generation and replacement of the capacity that retires could greatly improve the environmental outlook for NO_x.

The DEP expressed concern at the stakeholder workshops that state and federal emissions guidelines could not be met with the existing generation units. The supplemental analysis showed that the retirements and retrofits decrease total 2018 annual NO_x emissions by about 30%, 2018 summer seasonal emissions by about 35%, and 2018 emissions on the ten peak days by about 60% when compared to the DSM Focus resource scenario.

4. There is some legitimacy to the concern that the IRP has not tried to specifically address planning for energy needs with DSM.

There were no specific metrics other than LMP-related energy costs in the IRP analysis. There did not appear to be programs in DSM Focus aimed specifically at meeting energy needs.

CEAB Conclusions

1. The long term viability of continued operation of existing generating capacity is questionable

The DEP expressed concern at the stakeholder workshops that state and federal emissions guidelines could not be met with the existing generation units. The supplemental analysis showed that 1,400 megawatts of Connecticut's generation resources retired when the cost of required emissions retrofits to meet future environmental regulations were included in the going-forward cost calculations. The planned construction of new transmission lines within Connecticut and providing additional power input and export capability through connections with Massachusetts and Rhode Island, the over 1,400 megawatts of new generation, or upgrades, that are planned and expected to be in service by 2011, and the more than 700 megawatts of peak demand savings by 2011, make it unlikely that the capacity that is vulnerable will be prevented from retiring.

2. The analysis of the cost and benefits of Connecticut energy resource acquisitions capture the potential retirements.

There are on-going resource acquisition activities occurring in Connecticut under the regulation of the DPUC. The ECMB and the Distribution Utilities have the authority to identify and implement more energy efficiency and peak demand management resources. The Distribution Utilities have the authority to enter bilateral contracts to manage the costs and risks of standard service customers. The DPUC, in a Draft Decision, is close to allowing the Distribution Utilities the authority to secure Renewable Energy Credits (RECs) through long-term contracting. The economic benefits of all these activities derive the market prices expected. The retirement of capacity changes the outlook for LMPs and potentially the price of capacity secured through the FCM. The new resources must be evaluated under conditions that consider the uncertainty of the continued operation of the regions and Connecticut's older oil/natural gas steam capacity.

3. Future IRP analysis and Procurement Plans should expand the evaluation of retirement potential under all scenarios.

The supplemental analysis was able to capture retirements by including emissions retrofit costs in the going-forward cost calculations. The supplemental analysis was only able to capture the effect of retirements in one year, scenario and, case. Expanding the retirement analysis to all scenarios would create a more robust analysis. Further stakeholder input into the going-forward cost calculation would also improve the analysis and support better decision making.

APPENDIX J

CEAB Review of Environmental Regulations

— Impact on Generation Costs and Resource Options

2008 Comprehensive Plan for the
Procurement of Energy Resources

Prepared by:
The Connecticut Energy Advisory Board

Approved August 1, 2008

ENVIRONMENTAL REGULATIONS

Requirements of Procurement Plan

Section 51 of Public Act 07-242, An Act Concerning Electricity and Energy Efficiency (“Section 51”), requires Connecticut Light & Power (CL&P) and United Illuminating (UI) (together, “the Distribution Utilities”) to review the state’s energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources. As part of the plan, Section 51 requires that the Distribution Utilities assess, “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.”[172] Section 22a-200c(d)[173] requires the plan to include an evaluation of the impacts of RGGI.

IRP Emissions Analysis

The IRP analysis conducted by the Distribution Utilities partially addressed the requirement to address future environmental standards when they incorporated different levels of carbon emissions allowance costs within the scenario analysis process. The analysis assumed no changes over time to the current regulations governing nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions or toxics such as mercury. The Connecticut Department of Environmental Protection (DEP) is in the midst of evaluating emission reduction strategies for all stationary sources of NO_x. This is part of an overall state effort to implement emission reduction strategies that can help Connecticut reach attainment with the National Ambient Air Quality Standards (NAAQS), especially on “high electric demand days.

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172 Public Act 07-242, Section 51, b4

173 Secion 22a-200(d) Any allowances or allowance value allocated to the energy conservation load management program on behalf of electric ratepayers shall be incorporated into the planning and procurement process in sections 16a-3a and 16a-3b.

On summer days, higher demand for electricity results in a dramatic increase in ozone-forming air pollution. These are called "high electric demand days" or HEDD. The emission peaks occurring on HEDD are an obstacle to the continued progress in attaining air quality improvements in Connecticut and throughout the Northeast region. Although Connecticut has made significant progress in improving air quality over the past 30 years (for example, the number of ozone exceedance days in Connecticut has significantly decreased since 1975), in recent years it appears that the decreasing ozone trend has leveled off and ozone levels are no longer decreasing at a sufficient rate to meet attainment requirements in a timely fashion. For these reasons the DEP is evaluating additional emission reductions from electric generating units . Recent regional analyses have shown that significant emission reductions of NO_x are necessary to further Connecticut's progress toward ozone attainment.

Since the Distribution Utilities' analysis did not account for tighter NO_x and SO_2 regulations, the going-forward costs of older Connecticut oil/gas steam generation remained low and thus no retirements were warranted. The initial plan did not adequately consider retirements or retrofits for environmental controls and current efforts to reduce emissions, especially of pollutants such as NO_x that can dramatically impact ozone levels. Connecticut is currently implementing a suite of emission reduction strategies targeting a wide-range of sectors in the state, including electric-generating units. Even with the implementation of the full complement of strategies currently under consideration, current modeling does not project attainment of the federal health-based standards by 2020.

Stakeholder Input Workshops

CEAB sponsored a series of Stakeholder Input Workshops on environmental issues. The workshops were an opportunity for the various stakeholders to discuss regulations in the Connecticut DEP pipeline and the potential impacts of these regulations on the electric utilities. Key participants in the collaborative process were Connecticut DEP, the Distribution Utilities, the generation companies and Environment Northeast.

Because the stakeholders felt the Distribution Utilities had captured the current regulations in the IRP, the workshops focused on understanding future environmental emissions regulations. The pollutants studied included carbon, NO_x, SO_2 and Mercury.

Carbon

The stakeholders felt that the Distribution Utilities had handled the carbon regulations appropriately and satisfied the requirements of Section 22a-200c(d). RGGI implementation provides a need for carbon allowances and not a state cap on total CO_2 projection. Federal regulations are also likely to be a cap and trade program. Either RGGI or a federal cap and trade program will result in a carbon allowance market. Within the IRP analyses carbon allowance prices varies by scenario. By varying the carbon price, the stakeholders felt the Distribution Utilities had captured the impact of future scenarios.

The one area where more analysis is needed is in capturing the renewable build-out before determining whether regional carbon caps are in jeopardy of being exceeded by the resource solution sets or cases analyzed in the IRP.

Nitrogen Oxides (NO_x)

As discussed in “IRP Emissions Analysis”, additional reductions of NO_x are necessary to further progress in reaching Connecticut’s goal of attaining the eight--hour ozone NAAQS Currently, all of Connecticut is classified as “non-attainment” NAAQS.

Connecticut has two key NO_x emission programs for electric generating units:

- Ozone Season NO_x Budget. The program established per the NO_x SIP Call is between May 1 and September 30. The Clean Air Interstate Rule (CAIR) which was to be implemented in 2009 would have established a statewide ozone season budget.[174]
- High Energy Demand Days (HEDD). As discussed in “IRP Emissions Analysis”, HEDDs are the days most likely to result in ozone standard violations due to the ambient conditions. This situation can be exacerbated by transmission constraints which sometimes require generation to be provided by small, local, infrequently operated electric generating sources. These generating sources add a small amount of megawatts to the system while causing a drastic increase in NO_x emissions.

The summer ozone season budget established by CAIR is included in Table 1 below. DEP said that the state was already on track to meet the 2009 budget. The 2012 budget is identical to the 2009 budget in total tons emitted, but differs in allocation method. The 2009 allocation is based on megawatt hours and 2012 allocation is based on plant output.

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[174] Environmental Protection Agency’s CAIR was invalidated by a Federal Appeals court on July 11. While this creates uncertainty in the emissions regulation framework it does not abate the need to achieve the federal standards.

Table 1: Ozone Season NO_x Budget

Year	Budget	Allocation Method
2008	4466 tons	Allocated according to megawatt hours
2009	2691 tons*	Allocated according to megawatt hours
2012	2691 tons*	Allocation based on plant output

*The 2691 ton budget includes 3 industrial boilers and energy generating units greater than 15 megawatts. The budget for EGUs greater than 25 megawatts is 2559 tons.

The HEDDs are a key concern of DEP because Connecticut has been in non-attainment for the eight-hour ozone limit. There is a regional effort addressing this issue that includes Connecticut DEP that will conclude it's work by the Fall of 2008. In order to wait for the results of this regional effort, the Stakeholder Input Workshop participants are recommending that the HEDD type of emission considerations be incorporated into the 2009 plan analysis. Output from the additional modeling run sponsored by the Distribution Utilities will be used in the 2009 plan analysis.

At the facility level, NO_x is regulated by both a cap and trade program and by an absolute emission limit. In October, 1998, EPA finalized the "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone"—commonly called the "NO_x SIP Call." The cap and trade program falls under the NO_x SIP Call. The Distribution Utilities adequately modeled the allowances under this program in their IRP.

The absolute NO_x level set by the DEP was a point of discussion during the Stakeholder Input Workshops. The DEP has established short term (3–5 years) and long term (5–10 years) goals for facility emissions limits. The limits for oil fired boilers and emissions control technologies required are included in Table 2 below along with required emissions controls to meet emissions targets. The Selective Catalytic Reduction (SCR) technology would be required to meet the long term goals for boilers.

Table 2: Proposed NO_x Emissions Limits for Boilers

Time Frame	Emissions Limit (lb/mmbtu)	Emissions Control Technology required
Current Standard	0.15	Not applicable
Short-term Goal (3–5 years)	0.12	SNCR and/or water injection
Long-term Goals (5–10 years)	0.08	SCR

Sulfur Dioxide (SO_2)

SO_2 emissions are regulated by the DEP because they contribute to the formation of acid rain. Similar to NO_x, a regional cap and trade program exists for SO_2 and the DEP has set an absolute limit for each facility within Connecticut. The Distribution Utilities accurately modeled the allowances associated with the cap and trade program, but did not adequately model potential changes to the absolute limit.

The absolute SO_2 level set by the DEP was a point of discussion during the Stakeholder Input Workshops. The DEP has established long term (5–10 years) goals for facility emissions limits. The limits for oil fired boilers and emissions control technologies required are included in Table 3 below along with required emissions controls to meet emissions targets. Oil fired boilers would have to switch to lower sulfur fuels or install scrubber type technologies to meet the long term goals.

Table 3: Proposed NO_x Emissions Limits for Boilers

Time Frame	Emissions Limit (lb/mmbtu)	Emissions Control Technology required
Current Standard	0.3	Not applicable
Long-term Goals (5–10 years)	0.15	Scrubber

Mercury

The Stakeholder Input Workshop participants had limited discussion of Mercury regulations. DEP said that current mercury regulations would prohibit the development of additional coal facilities in the state. As a result, the additional modeling sponsored by the Distribution Utilities does not include any new coal-fired generation facilities.

Additional Modeling to Incorporate Future Regulations

As part of the collaborative process, the Distribution Utilities sponsored an additional model run performed by The Brattle Group. The additional model run is built off the Current Trends and DSM focus case from the IRP. With respect to emissions, the goal of the additional modeling is to incorporate the future regulations as discussed in the Stakeholder Input Workshops.

Because of time constraints, the additional modeling effort was focused on one year, 2018. The long term DEP goals for SO_2 and NO_x discussed above were assumed to be in effect. This required boilers to install both SCR and SO_2 scrubber emissions controls. The cost of these emissions controls was obtained from a report by Northeast States for Coordinated Air Use Management called, "Assessment of Control Technology Options for BART-Eligible Sources."[175] The cost of emissions controls was incorporated into the going-forward cost calculation for each facility.

Suggestions for Future Scenario Analysis

While the additional model run was only performed for one scenario and year for the 2008 Procurement Plan, the stakeholder group matched DEP emission regulation goals with the other scenarios and years as shown in Table 4. The logic behind the scenario emissions regulations assignments are as follows:

- NO_x Rates: DEP has established both short term (3–5) year and long term (5–10 year) goals for NO_x emissions rates at facilities. The proposed scenario emissions regulations vary in the timing of when the long and short term goals are implemented. For example, the Current Trends NO_x rates achieve the short term goal in 3 years and the long term goal in 10 years, while to Climate Constrained NO_x rates achieve the long term goal in 5 years.
- NO_x Budget: As described in "Nitrogen Oxides (NO_x)", there is a state-wide NO_x budget which decreases in 2009. As with the NO_x rate, the timing of the decrease varies by scenario.
- SO_2 Rate: DEP has established a long term (5–10 year) goal for SO_2 emission rates. The scenario goals differ in the timing of when this long term goal is achieved. All scenarios achieve the long term goal in ten years (2018) except the climate constrained scenario which achieves the long term goal in 5 years.
- CO_2 Cap: RGGI has established Regional CO_2 Cap for 2009–2018. Carbon emissions in 2009–2014 are capped at 4% above 2000–2004 average emissions. Carbon emissions cap in the period 2015–2018 decreases by 2.5% per year. There will be no change in 2009–2012 CO_2 cap, but the 2013–2018 cap will be re-evaluated in 2012 and may change. The scenarios are either assigned RGGI or accelerated RGGI. Accelerated RGGI would mean that the regional cap ratchets down more quickly than currently planned.

[175] Northeast States for Coordinated Air Use Management, "Assessment of Control Technologies for BART-Eligible Sources". March 2005.

Table 4: Proposed Emissions Regulations by Scenario

	EGU NO_x Rates (lb/mmbtu)	Statewide NO_x Budget	EGU SO_2 Rates (lb/mmbtu)	Connecticut CO_2 Cap
Current Trends	0.12 by 2011 0.08 by 2018	2691*	0.3 by 2011 0.15 by 2018	RGGI
High Fuel	0.15 by 2013 0.12 by 2018	4466*	0.3 by 2011 0.15 by 2018	Accelerated RGGI
Climate Constrained	0.08 by 2013	<2691*	0.3 by 2011 0.15 by 2013	Accelerated RGGI
Low Stress	0.12 by 2013 0.08 by 2018	2691*	0.3 by 2011 0.15 by 2018	RGGI

*The 2691 ton budget includes 3 industrial boilers and energy generating units greater than 15 megawatts. The budget for EGUs greater than 25 megawatts is 2559 tons.

APPENDIX K

Supplemental CEAB and Utilities Collaborative Analysis

2008 Comprehensive Plan for the
Procurement of Energy Resources

Prepared by:
The Connecticut Energy Advisory Board

CEAB
Connecticut Energy Advisory Board

Approved August 1, 2008

SUPPLEMENTAL CEAB AND UTILITIES COLLABORATIVE ANALYSIS

Introduction

As part of the CEAB review and modification of the Distribution Utilities' IRP, the CEAB requested that supplemental analysis be conducted. This analysis served two purposes. The first being to demonstrate some techniques to enhance the analytical scenario analysis, allowing more insightful observations and conclusions in future procurement planning cycles. The second purpose is get a glimpse of how the environmental and cost metrics could change when the combination of the most aggressive plan for DSM (DSM Focus), the potential for a renewable generation build out that satisfy RPS requirements and more fully capturing the environmental regulations under consideration and their effect on the older existing generation in Connecticut, CEAB believes the supplemental analysis has demonstrated the viability of the improved techniques for future planning analyses. While the actual documentation of the modeling efforts in this supplemental analysis is being prepared by Distribution Utilities, this small report provides the basis for recommendations made in the body of this report.

Utilities IRP Analysis

This Appendix is intended to briefly summarize the Distribution Utilities' IRP Analysis, the ensuing modifications suggested through a stakeholder process, and the resulting CEAB/Utilities collaborative supplemental analysis. The supplemental analysis takes a different perspective on several key assumptions underlying the IRP and is presented here to illustrate the potential value of approaching future analyses in a similar way. The supplemental analysis was only modeled under one scenario (Current Trends) and for one test year (2018) and therefore should not be used to draw definitive conclusions. However, important high level observations can be made about the significance of the assumptions underlying the IRP analysis. These observations indicate ways in which future IRP analyses could be improved.

Overview of Utilities IRP Analysis

The IRP Process

On January 1, 2008 United Illuminating and Connecticut Light & Power jointly filed an Integrated Resource Plan for Connecticut as required in Section 51 of Public Act 07-242. This plan was prepared under the direction of and on the utilities behalf by The Brattle Group.

The IRP was developed utilizing a scenario planning approach, where different resource options in the future were analyzed with four very distinct plausible future sets of conditions. The four scenarios varied assumptions regarding fuel prices; the electric peak load and energy requirements; the cost of and potential concerns regarding the siting of new generation; and the prices for CO_2 allowances. The IRP is a very comprehensive document which includes extensive documentation of the assumptions used in developing the four scenarios: Current Trends, Strict Climate, High Fuel/High Growth, and Low Stress. An electricity market model was used to analyze each scenario in the years 2011, 2013, 2018 and 2030, in order to provide the 3, 5 and 10 year information as required by the legislation.

The IRP began with an extensive quantification of resource needs. This needs assessment for each scenario considered the outlook for demand and energy growth beginning with the Connecticut forecast prepared by ISO New England. The base resources assumed to contribute to meeting future need were: the all existing generation in Connecticut; the planned new capacity additions that were awarded contracts in the 2006/2007 DPUC Long Term Capacity procurement; an allowance for the addition of some quick start peaking generation (500 megawatts) within southwest Connecticut as a proxy for the then on-going procurement docket for peaking capacity; and a growth of Demand-Side Management programs consistent with funding growth. This well documented process considered the potential local sourcing requirements for Connecticut from ISO New England and included an evaluation of the adequacy of energy and capacity market revenue for existing generation as compared with their going-forward costs. Their analysis led to the assumption that the existing generation in Connecticut would remain economically viable and that it would continue to operate throughout the study period. Section IIC, which begins on page 8, and Appendix C of the utilities' IRP provides the explanation and the details of the existing and committed resources available over time.

The IRP analysis gained insights from modeling four resource solution cases in order to evaluate the effects that different resources have on cost and other metrics. These four resource solution sets, Conventional Gas, DSM Focus, Nuclear, and Coal were developed and described within the IRP in Section IID beginning on page 15.

The IRP developed various metrics to show costs to consumers and the total going-forward cost differences between potential resource plans. Additional metrics were calculated to show how the resource solution cases compared in terms of the annual emissions of CO_2, NO_x and SO_2 and the trend of natural gas consumption by the electricity sector. The IRP considered two different assumptions regarding how the cost of total resources translate into the costs to consumers in Connecticut. The first regime is the market regime where the cost to consumers for electric generation service was based energy and capacity costs at their respective market clearing prices. The second is the cost of service regime where all generation and fuel costs were modeled at the actual cost of the each generating unit fuel, O&M, Carrying costs based on embedded transfer costs. All cost metrics were each calculated under each of these two regimes. The market regime closely mirrors the impacts on Connecticut consumers given that standard service is currently procured at market prices. The cost of service regime is an extreme example of where costs to consumers would be if all generation and fuel costs were billed to consumers at cost. In other words this regime assumes the asset outputs are re-acquired at the historical transfer costs and cost of service bills are reinstated. The differences between these regimes, and the resulting key metrics, are discussed within Section IIIA of the utilities IRP. In total, the four resource solutions each modeled under four the scenarios for the future and under the two market constructs resulted in at least 32 cases for analysis.

The utilities and The Brattle Group highlighted ten key findings that they concluded from analysis of the metrics. These findings are provided in Appendix B of this report and in much detail within the IRP Section IIB, beginning on page 39.

The IRP Results

The IRP had four recommendations based on these findings:

- Maximize the use of demand-side management within practical, operational and economic limits, to reduce peak load and energy consumption.
- 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.
- Evaluate the structure and cost of Connecticut's renewable portfolio standard in the context of a regional re-examination of the goals and costs of similar policies in New England.
- Consider potential ways to mitigate exposure of Connecticut consumers to the price and availability of natural gas.

- These recommendations are also provided in Appendix B of this report and discussed more fully in the IRP Section IV, beginning on page 45.

Stakeholder Input

The CEAB role in the process, as described elsewhere in this report, is to review and modify the plan filed by the utilities and submit it to the DPUC. As part of its review, the CEAB convened several Stakeholder Input Workshops. The following sections discuss concerns about the utilities IRP that arose from the CEAB analysis of the plan and from stakeholder input.

DSM

All participants at the DSM Stakeholder Input Workshop agreed that every economically feasible DSM should be implemented in Connecticut. DSM must be the first step in resolving future capacity shortfalls. The stakeholders suggested that DSM should be assumed in at the maximum economic level before considering scenarios to meet remaining need. In other words, DSM must continue to be a main focus for meeting Connecticut’s energy resources.

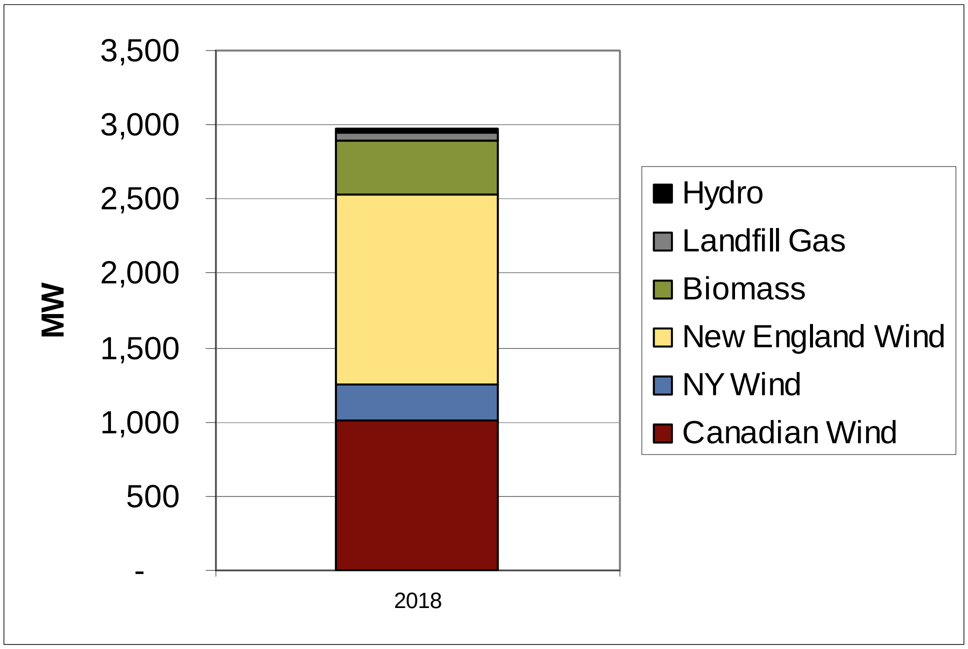
RPS Attainment

Several stakeholders including Connecticut Clean Energy Fund (CCEF) felt that the Distribution Utilities had not conducted a thorough analysis of the potential renewable supply to meet the Connecticut RPS. As part of the CEAB review process, a Renewable Stakeholder Input Workshop was convened to further explore the issue of renewable electric power supply. One output of the stakeholder group was a regional market overview and REC pricing analysis that showed the following:

- A surplus of resource potential exists to meet 2018 New England RPS total requirements.
- Currently the total of the proposed projects is sufficient to meet 2018 New England RPS requirements.
- There is little potential for indigenous Connecticut resources to meet Connecticut RPS requirements as the IRP had concluded.
- Long-term contracting for RECs or Energy Output and RECs should secure renewable energy at REC prices substantially below ACP ($30 to $35 per megawatt hour).
- An expected build-out of renewable energy generation facilities will likely include Canadian facilities exporting to New England.

The stakeholder analysis produced an estimated 2018 renewable build-out, shown in Figure 7 and an estimated 2018 REC price of $32. Please see Appendix H for more information on the renewable energy analysis.

Figure 7: 2018 Renewables Build-out



This analysis suggests that significant renewable capacity will be added to the ISO New England system by 2018 in order to achieve the regional policy goals. The stakeholders were concerned because the LMP, capacity, and total cost impacts of the projected renewable additions were not included in the Distribution Utilities analysis.

Generation Retirement due to Emissions Regulations

Stakeholders were concerned that the Distribution Utilities analysis did not appropriately assess, "the impact of current and projected environmental standards,"[176] as required by Section 51. The Stakeholder Input Workshop participants discussed the need to include the Connecticut DEP's projected regulations of NO_x and SO_2 in the IRP analysis. If the long term DEP goals for SO_2 and NO_x are assumed to be in effect older oil/gas steam boilers used to generate electricity in Connecticut would have to either not run and retire or install both SCR and scrubber emissions controls. Table 2 and Table 3 show the current and projected DEP emission limits for NO_x and SO_2 as well as the technologies that generators would need to install to be able to comply with these

176 See Public Act 07-242, Section 51, b4

limits. Please See Appendix J for further discussion of the projected emission regulations and control technologies.

Table 2: Proposed NO_x Emissions Limits for Boilers

Time Frame	Emissions Limit (lb/mmbtu)	Emissions Control Technology Required
Current Standard	0.15	Not applicable
Short Term Goal (3-5 years)	0.12	SNCR and/or water injection
Long Term Goal (5-10 years)	0.08	SCR

Table 3: Proposed SO_2 Emissions Limits for Boilers

Time Frame	Emissions Limit (lb/mmbtu)	Emissions Control Technology Required
Current Standard	0.3	NA
Long Term Goal (5-10 years)	0.15	Scrubber

Since the Distribution Utilities' analysis did not account for tighter NO_x and SO_2 regulations the costs of older Connecticut oil/gas steam generation remained low and thus no retirements were warranted. As a result of the stakeholder input, the CEAB suggested analyzing the impact the projected emission regulations on plant retirements. Because the projected Connecticut DEP regulations are likely similar to regulations being considered in all New England states, the analysis was done for all applicable units in ISO New England. The analysis incorporated the cost of emissions controls into the going-forward cost calculation for each facility emissions rates above the regulations for 2018 and projected the amount of plant retirements due to the additional cost.

The analysis used emissions control costs obtained from a report by Northeast States for Coordinated Air Use Management called, "Assessment of Control Technology Options for BART-Eligible Sources."[177] Units were assumed to invest in the control technologies if economics indicated that by continuing to operate the generation owner would receive enough revenue to cover costs and a fair return on the incremental investment in the retrofit. This translates roughly to a criteria that generation units will invest and continue to operate if the payback period would be less than 5 years; will retire if the payback period would be over 10 years; and will retire about 50% of the megawatts if the payback period between 5 and 10 years.

[177] Northeast States for Coordinated Air Use Management, "Assessment of Control Technologies for BART-Eligible Sources". March 2005.

This analysis resulted in the identification of 2,655 megawatts of oil and gas steam generation in New England, 1,267 megawatts in Connecticut alone, by 2018 that are likely to retire due to tightened emissions regulations. This level of retirements would have significant implications for capacity needs in the region and therefore the stakeholders believed the impacts of the projected environmental regulations should be included in the Distribution Utilities modeling.

Accounting of Emissions Impacts

The Distribution Utilities analysis presented the emissions impacts of the scenarios as annual tons emitted. Stakeholders commented that this view does not give a sufficient picture of the impact of the emissions, particularly NO_x. Ground-level ozone, which is formed when sunlight reacts with NO_x emissions, usually reach unhealthy levels during the summer. It was suggested that additional metrics of the emissions impact be added to the analysis that report the total emissions of NO_x and SO_2 during summer months and during the 10 peak load days of the year. This would allow the model runs to be judged by their ability meet long term emissions goals and contribute to better regulation design.

Supplemental Analysis

The CEAB collaborated with the Utilities and their consultant, The Brattle Group, to conduct a supplemental analysis that modified the IRP modeling based on the issues raised the stakeholder process detailed above. This supplemental analysis was only conducted under the Current Trends scenario and for a '10-year Look' (2018 was the only year modeled). In its current abbreviated form this analysis cannot be used to determine planning decisions, however it does illustrate significant potential improvements to the way in which IRP analysis is conducted in the future.

Supplemental Model Runs

The CEAB, informed by the stakeholder input and its own analysis, concluded that a new perspective on the base case used in IRP analysis could be beneficial in informing long-term planning. The CEAB collaborated with the utilities to develop the inputs for additional model runs that illustrate the impact that realistic assumptions regarding renewable resources and retirements/retrofits due to emissions regulations can have on the analysis. The model runs compared in this supplemental analysis are discussed below. Please see the utilities report about the results of the supplemental analysis for more details.

Base Case

In the utilities IRP, DSM was determined to be the least cost way to address capacity needs. The CEAB agrees with all stakeholder parties that the maximum amount of economically feasible DSM should be implemented. Additionally, the CEAB believes that the higher DSM Focus of aggressively investing in economic DSM would be appropriate to assume in the supplemental IRP analysis. As with the DSM Focus in the original IRP analysis, this DSM Focus level is in addition to the growing level of DSM funding and impact assumed in the base case. The DSM Focus case achieves the objectives of the legislation to find economic DSM programs that can effectively eliminate demand and energy growth for Connecticut. Therefore, the DSM Focus solution set run under the Current Trends scenario was used as the base case for the supplemental analysis. This case required 900 megawatts of generic, natural gas-fired capacity to be modeled in order to meet system-wide needs in 2018.

Renewable Case

The CEAB agrees with the utilities' conclusion that there is little potential for renewable capacity development within Connecticut. However, it is likely that renewable resources will be added to the ISO New England system to comply with the Renewable Portfolio Standards in the region. The development of these resources in the region will have significant impacts on system-wide LMP prices, capacity needs in the region, and the cost of meeting Connecticut's RPS. Starting from the DSM Focus base case, the CEAB requested a run that included all the renewable capacity builds and imports projected to meet regional RPS requirements in the stakeholder process.

The renewable resources (with wind's contribution derated to 20% of nameplate capacity) totaled 947 megawatts of capacity. With these resources assumed to come online by 2018 need for the 900 megawatts of generic capacity built in the base case was eliminated.

Retirements and Retrofits due to Emissions Regulations

The next run requested by the CEAB added the impacts of the emissions regulations, discussed and analyzed in the stakeholder section of this appendix, to the DSM and renewable assumptions. The retirement of 1,400 megawatts of older oil and gas steam generation in Connecticut , a total of 2,655 megawatts in New England, due to assumed tighter NO_x and SO_2 regulations required the addition of 2,400 megawatts of generic capacity in 2018.

In this single case for the single scenario Current Trends, this shows a reasonable likelihood that there will be retirements resulting from more demanding NO_x and SO_2 emission rate regulations. The CEAB believes this case would be a more solid foundation for an IRP analysis than the base case used in the initial Utilities analysis. Assumptions about generation retirements and additions are likely to have significant impacts on the results of the modeling. The assumptions that underlie this case project the impacts of high level policy objectives (regarding renewable resources and emissions levels) making for a more realistic starting point for analysis.

Impact of adding a Nuclear Unit

Finally, due to the interest in nuclear development, the CEAB requested a run in which a 1,200 megawatts nuclear unit was assumed to come online in 2018. This resulted in only 1,200 megawatts of generic, gas-fired capacity being required to fill the remaining need.

Illustrative Modeling Observations

These model runs are solely a representative 10-year look. Planning conclusions cannot be drawn from these runs without them being part of a more extensive scenario analysis. However, observations drawn from these runs indicate that the IRP analysis could be enhanced by adopting this configuration in the future. The following observations are intentionally high-level as they are only informing conclusions about the process rather than numbers based planning conclusions.

Cost

When renewable capacity is added to the system there are multiple cost impacts, these include: the cost of the new resources may be higher than conventional, the LMPs may be lower due to price suppression, and the REC price maybe lower due to increased renewable supply. When comparing the Renewable case to the DSM Focus base case the cost metrics used in this study change by less than one percent. Overall, assuming that regional RPS are met in a realistic way does not appear to change the base case costs significantly.

All of the cases in the supplemental analysis had essentially the same level of overall cost under the Market Regime construct because these cases did not change the marginal price of electricity. These cases compare favorably to the Conventional solution set run under the Current Trends scenario in the original analysis which does change the marginal price of energy enough to significantly increase the cost metric under the Market Regime construct.

When the cost metrics are compared under the Cost of Service construct the cost impacts of the cases are more differentiated. The new capacity required under the Retirements case adds about five percent to the cost metric when compared to the DSM Focus base case. The addition of nuclear capacity doubles the impact on the cost metric. However, these impacts are less than the difference between the DSM Focus and the original analysis Conventional case. These cases do not appear to add inordinate costs.

Carbon Dioxide

The supplemental cases have a significant impact on regional CO_2 emissions. Under the original analysis, the total regional CO_2 emissions in 2018 exceeded the RGGI emission budgets for the New England states in almost all cases. The DSM Focus case run under Current Trends got the region close to the budget levels but still exceed these presumed goals for CO_2 emissions. The addition of renewable resources in the supplemental analysis significantly lowered regional CO_2 emissions and put the region comfortably within its budget for 2018. The impact of the Retirements case further lowered total CO_2, but to a lesser degree, because the new natural gas-fired capacity emits less CO_2 per unit of electricity produced than older oil-fired generators. Finally, the addition of a CO_2 free energy source in the Nuclear case further lowers total CO_2 emissions in the region, about the same degree as the addition of renewable did.

From these supplemental cases we can observe that the assumptions regarding renewable resources and retirements can have a significant impact on the CO_2 emissions metric. Reasonable assumptions about the attainment of regional renewable resource and NO_x and SO_2 emission goals seem to have beneficial side-effects on the CO_2 emissions metric. While the CO_2 abatement cost in the nuclear and the renewable cases are higher than the cost of allowances there are other benefits to be considered. The CEAB suggests consideration of a metric that combines the effect of abatement of all emissions and considers the additional impact of renewable resources avoiding the need for Alternative Compliance Payments.

Nitrogen Oxide

The supplemental analysis implemented the metrics that totaled annual, summer, and 10 peak day emissions of NO_x at regional and state levels. The summer and 10 peak day metrics proved to give valuable insight into the impact of changes to the system on Connecticut's emission goals.

The addition of renewable resources had little impact on the NO_x emissions metrics however the case with retirements and retrofits made a significant difference. Under this one scenario for the year 2018 the retirements and retrofits decrease total annual NO_x emissions by about 30%, summer seasonal emissions by about 35%, and emissions on the 10 peak days by about 60% when compared to the DSM Focus base case. The addition of nuclear capacity contributed to slight further declines. Because NO_x emissions are most dangerous at specific times of year the new metrics give policymakers an important view of the potential impact of emission limits.

Nuclear

The addition of a nuclear unit had positive impacts on the emission metrics with less cost impacts than the Conventional solution set run under the Current Trends scenario in the original analysis. The CEAB notes that the capital cost of nuclear used in this study seems low given recent trade press. Additionally, of all the resources considered in this study nuclear has the most risk for those costs to increase significantly. Therefore caution should be used when making conclusions favoring nuclear based on the cost metrics. The potential improvements in the environmental metrics does however suggest that nuclear deserves further investigation. Furthermore, because nuclear is already above market increases in nuclear costs will have disproportionately large impact on the total going-forward resource cost.

Conclusions

The supplemental runs were only conducted for one year under one scenario. They illustrate the benefits of enhanced modeling of the renewable market potential and the ramifications of evolving environmental regulations to the overall modeling process. However, they indicate that several important conclusions are possible if the assumptions regarding DSM, renewable resource, and retirements and retrofits due to emission regulations were applied across all cases and scenarios and similar findings were reached. Integrated resource planning in Connecticut can benefit by starting from the perspective that projected high level policy goals (such as increased renewable energy and tighter emissions limits) will be met. The cost of taking action to attain these goals seem to be less than one might expect and there are many benefits to attaining these goals that may not be expected. For instance, in this one case, achieving RPS goals under the DSM Focus base case makes achieving or surpassing the RGGI CO_2 emission goals plausible. The implementation of these goals have collateral impacts on other metrics that are important to consider in planning decisions therefore starting with attainment as a base assumption is valuable.