CONNECTICUT ENERGY ADVISORY BOARD

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September 2, 2005

Via Electronic Filing and First Class Mail

Ms. Louise E. Rickard, Acting Executive Secretary
Department of Public Utility Control
Ten Franklin Square
New Britain, CT 06051

Re: Docket No. 05-07-14Ph01: <u>DPUC INVESTIGATION OF MEASURES TO REDUCE FEDERALLY MANDATED CONGESTION CHARGES</u>

Dear Ms. Rickard:

On behalf of the Connecticut Energy Advisory Board (CEAB), I am pleased to submit the CEAB's *Preliminary Assessment of Connecticut's Electric Supply and Demand Near Term Requirements for Reliability and Mitigation of Federally Mandated Congestion Charges* ("Interim Report") pursuant to the Department of Public Utility Control's (DPUC) Procedural Order dated July 25, 2005 in the above captioned matter. The CEAB is pleased that its ongoing energy planning work is able to be of assistance to the DPUC.

Please add the following representatives of the CEAB to the Service List in this matter:

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Thank you for your assistance. Please contact me with any questions about this filing.

Sincerely,

Mary J. Healey

Mary J. Healey, Esq.
Consumer Counsel
Vice Chairman
Connecticut Energy Advisory Board

cc: CEAB Members
Service List

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Preliminary Assessment

Connecticut's Electric Supply and Demand

Near Term Requirements for Reliability and Mitigation of Federally Mandated Congestion Charges

The Connecticut Energy Advisory Board

September 2, 2005

Connecticut's Electric Supply and Demand

Near Term Requirements for Reliability
and
Mitigation of Federally Mandated Congestion Charges ("FMCCs")

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Preface

The Connecticut Energy Advisory Board's ("CEAB") composition and function were substantially reformed by Public Act 03-140.[1] The change equipped Connecticut to anticipate rather than react to emerging energy needs. The CEAB's statutory responsibilities now include, among others: preparing an annual Energy Plan; establishing criteria for evaluating energy proposals; participating in various Siting Council proceedings; implementing and conducting an RFP to solicit energy projects; and representing the State in regional energy system planning processes conducted by New England's Independent System Operator, ISO-NE. Together, these functions enable Connecticut to facilitate market-based energy solutions that further the State's energy, environmental, and economic development objectives.

This *Preliminary Assessment of Connecticut's Electric Supply and Demand* ("Interim Report") is part of the CEAB's 2005 assessment of Connecticut's need for new energy resources, infrastructure and conservation initiatives ("2005 Needs Assessment"). The Interim Report is provided in response to a request from the Department of Public Utility Control ("DPUC") in Docket No. 05-07-14 Phase I, in which the DPUC will implement Section 12(a) of Public Act 05-01 "*An Act Concerning Energy Independence*" ("the Act"). The DPUC intends the Interim Report to provide the factual basis for its orders implementing near term measures to reduce federally mandated congestion charges. The CEAB will provide the DPUC a Final Report in November 2005, coterminous with the completion of the CEAB's 2005 Needs Assessment. The CEAB Final Report is expected to assist the DPUC in drafting an RFP to solicit long-term projects and in evaluating RFP responses pursuant to Section 12(c) of the Act.

Pursuant to the Procedural Order dated July 25, 2005 in Docket No. 05-07-14, Phase I, all interested parties will have an opportunity to provide written comment on the Interim Report. The CEAB will consider all comments filed in Docket No. 05-07-14 Phase I as it prepares its Final Report. Additionally, if any interested person has comments that may inform the CEAB's 2005 Needs Assessment but do not pertain to the Interim Report and will not be filed in Docket No. 05-07-14 Phase I, CEAB will also consider them. Please direct comments to:

Gretchen K. Deans
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1 Members of the CEAB include heads of the following agencies: Department of Public Utility Control; Department of Environmental Protection; Office of Consumer Counsel, Office of Policy and Management, Department of Agriculture; and Department of Transportation. In addition, three members of the Board are appointed by the Governor, Speaker of the House and President Pro Tempore of the Senate, respectively.

Acknowledgements

The CEAB has retained a consulting team led by La Capra Associates of Boston, Massachusetts to conduct this assessment. The consulting team is reviewing planning studies and information available from entities involved in Connecticut's electric sector to assist the CEAB in carrying out its planning responsibilities under Public Act 03-140. The CEAB appreciates the cooperation that has been offered and wishes to acknowledge these efforts.

First, the Connecticut Siting Council ("CSC") has afforded the CEAB an opportunity to participate in its ongoing proceeding regarding its 2005 Review of the Ten-Year Forecast of Electric Loads and Resources (Docket No. F-2005). The CEAB also appreciates the information provided to the CSC and CEAB in this proceeding by Connecticut's electric distribution companies and generation companies and by the Independent System Operator of New England ("ISO-NE").

In addition to its participation in the CSC proceeding, the CEAB acknowledges and appreciates ISO-NE for its planning initiatives, for affording the CEAB the opportunity to participate in its Planning Advisory Committee and Regional System Planning process, and for making its personnel available to the CEAB to describe and explain its planning methods and results. Similarly, Connecticut Light and Power, United Illuminating, and the Connecticut Municipal Electrical Energy Cooperative have made their planning information and personnel available to the CEAB. The ISO-NE and the Connecticut electric distribution companies have direct roles in the planning and implementation of the electric system in Connecticut, and their cooperation with CEAB is appreciated.

Additional sources of information for this effort include the Federal Energy Regulatory Commission, the Connecticut Energy Conservation Management Board, the Connecticut Clean Energy Fund, and the Institute for Sustainable Energy.

The observations and conclusions offered in this report, while relying on information from many, are offered as those of the CEAB alone.

Executive Summary

Connecticut consumers' exposure to federally mandated congestion charges ("FMCC"s) is substantial and multifaceted. The Independent System Operator of New England's ("ISO-NE") plans for both locational capacity markets (postponed to at least October 2006) and a two-zone energy market in Connecticut are important elements of the cost exposure. In addition, other system reliability criteria will result in FMCCs being borne by Connecticut's consumers. The current Reliability Must Run ("RMR") contracts between ISO-NE and local generators are perhaps the most obvious example.

The completion of recently approved transmission projects, referred to as Phase I and Phase II, will mitigate some of the FMCCs. However, even after the implementation of the projects, significant transmission constraints – both interstate and intrastate – and associated FMCC cost exposure will remain. Connecticut has available to it a variety of means to mitigate FMCCs, including but not limited to measures created by Public Act 05-01, *An Act Concerning Energy Independence*. The near term options include measures that reduce peak demand, as well as new generation and additional transmission resources.

The CEAB's preliminary assessment of Connecticut's electric system and the near-term outlook for loads, supplies, transmission and FMCCs leads to the following observations:

1. In 2006, FMCC exposures will be most acute in Southwest Connecticut ("SWCT").[2] Despite FERC's delay of a final decision on ISO-NE's Locational Installed Capacity ("LICAP") proposal, ISO-NE plans to implement a distinct energy pricing zone for SWCT in January, 2006. Reliability Must Run ("RMR") and operating reserve costs will likely remain high in that area through 2006. The Phase I, Bethel-Norwalk transmission line, is not slated for operation until year-end 2006. Near-term actions to mitigate FMCCs should concentrate in this zone, particularly in the Stamford/Norwalk sub-area, to have maximum benefit to SWCT and the State as a whole.
2. At this juncture, to the CEAB's knowledge, neither ISO-NE nor the Connecticut electric distribution companies have definitive studies that would provide the information needed to specify optimal locations for distributed resources.
3. Significant FMCC exposures will remain in 2007 and 2008, although completion of the Bethel-Norwalk transmission line is expected to temper the exposure, particularly in SWCT.
4. The level of FMCCs in the 2006 to 2008 period is very sensitive to peak load levels. Forecasts of peak load, net of contributions from conservation and load management

[2] The term SWCT is used in this Report to mean the load-zone as being considered by ISO-NE.

Actions Pertaining to Connecticut's Transmission and Import Capability:

Steps associated with transmission that could help reduce FMCCs include the timely completion of the Bethel-Norwalk 345 kV line, as well as the Mystic-Wood River reconductoring project, both scheduled for 2007. In addition, it would be useful for Connecticut to assess the possibilities for incremental transmission, particularly intra-state, that may be able to substantially mitigate FMCCs. The Connecticut electric distribution companies should undertake these studies.

Actions Pertaining to New Generation Resources:

Generation resources include preferred generation resources – such as distributed generation, combined heat and power, and renewables – as well as other types. The CEAB recommends that the DPUC encourage those resources that compare favorably to the CEAB's preferential resource criteria with an emphasis on those to be sited in locations that likely will maximize FMCC reductions. As for other generation resources, there are some, such as those providing quick start capabilities, that can provide significant benefits, particularly if located in the Stamford/Norwalk sub-area and elsewhere in SWCT. In general, however, large scale generation resources should be solicited, if at all, through the RFP process.

Additional Actions:

Another action that could help advance consumer interests relative to potential cost exposure is active participation in ISO-NE decision-making, which in the near term will include transmission planning studies, notably the Southern New England Reinforcement Project; analyses of near term resource adequacy; and the design and implementation of a locational forward reserve market.

1. Introduction

Connecticut's electric infrastructure is reaching the limits of its ability to provide reliable service to meet the State's growing demand for electricity, particularly as it pertains to the electric requirements in southwestern Connecticut. During the past ten years, the supply and demand balance in Connecticut has changed. At this time, Connecticut has come to rely significantly on power imports from sources outside the State during times of peak demand. The State has also become increasingly vulnerable to power disruptions attributable to unplanned outages of in-state generation and transmission facilities.

Peak demand in Connecticut has grown steadily across the last decade. Data from ISO-NE indicates that peak loads in the State increased at an average annual compound rate of 1.2% from 1994 through 2004, reaching 6,444 MW in 2004. This represents a 12% increase over the decade, or about the equivalent of the production capability of one 700 megawatt ("MW") base load power plant. Since 1994, average growth in peak demand for Connecticut has been somewhat lower than growth in the New England control area. The corresponding annual growth rate for the region has been roughly 1.6%. This is a 17% increase over the decade, or roughly 3,600 MW in total.

Connecticut's generation supply has not kept pace with its growth in demand. Major power plant retirements – Connecticut Yankee in December 1996 and Millstone Unit 1 in December 1997 – which provided 1,200 MW of base load power production, were replaced gradually over time with 1,650 MW from three gas-fired combined cycle power plants: Bridgeport Energy in 1998, Lake Road in 2001, and Milford Power in 2004. Peaking power plant additions in Wallingford and Devon, which together provide 350 MW, have been offset by the retirement or deactivation of units in Bridgeport Harbor, Devon, and New Haven.

In addition, transmission limitations both within the State and for imports into it have become increasingly problematic. The limitations of the Connecticut transmission system to allow power imports from the rest of New England were evident during the extended outages of the Millstone units in 1997 and 1998 and have remained the focus of transmission planning. While some transmission upgrades have been implemented, other serious limitations to the reliable transfer of power persist. For example, the Lake Road facility's location in northeastern Connecticut effectively precludes its ability to serve load in Connecticut at peak times. This exacerbates the gap between Connecticut generation and load.

Full solutions to these challenges will take time. The Bethel-Norwalk transmission line, under construction for operation in 2007, and the Middletown-Norwalk transmission line, planned for operation in 2009, will significantly improve the ability to transfer power within the State. With respect to generation however, there are no major facilities currently under active development. And many generation units in the State are quite old. Consequently, in addition to ongoing efforts to utilize energy

CEAB's composition and function. Among other things, it requires long-term energy planning and the development of preferential selection criteria to ensure that the State's energy decisions work in concert with environmental and other goals; it also institutes a process for the active solicitation of energy infrastructure proposals.

More recently, in July 2005, the General Assembly passed and the Governor signed Public Act 05-01 "*An Act Concerning Energy Independence*." Among other things, the Act created a series of instruments that equip the State to encourage and to facilitate the deployment of preferred energy resources so as to mitigate FMCCs.

In furtherance of its energy planning responsibilities under the 2003 Act, the CEAB is comprehensively reviewing Connecticut power system planning studies. Its review will result in an independent energy needs assessment in the fall of 2005. This Interim Report provides a preliminary view of that more comprehensive needs assessment. It is provided at the request of the DPUC in order to help inform the DPUC's decisions, pursuant to the 2005 Energy Independence Act, as it undertakes to encourage investment in preferred energy resources and maximize the reduction of FMCCs.

2. DPUC Investigation of Measures to Reduce FMCCs

The DPUC opened Docket No. 05-07-14, Phase I to implement Section 12 of the Energy Independence Act. Sections 12(a) and (c) of the Act require the DPUC to implement near-and longer-term measures to reduce FMCCs.

In Phase I, pursuant to Section 12(a), the DPUC will identify by November 1, 2005 those near-term measures that can best reduce FMCCs and that can be implemented by the electric distribution companies at least in part by January 1, 2006. Subsequently, pursuant to Section 12(c), the DPUC will develop and issue an RFP for longer-term projects to further reduce FMCCs.

In a Procedural Order dated July 25, 2005, the DPUC emphasized the need for a sound factual basis to guide its findings and decisions. Accordingly, the DPUC requested that the CEAB submit a report no later than August 18, 2005 to provide a starting point for DPUC decisions on which near-term measures to implement. More specifically, the DPUC requested information related to the CEAB's ongoing assessment of the State's supply and demand status, including:

1. quantification of anticipated FMCC costs;
2. an analytical framework to facilitate an assessment of the cost/benefit effectiveness of various measures to mitigate FMCCs; and
3. a description of the type and location of resources that would best reduce FMCCs.

On August 18, 2005, the DPUC modified the procedural schedule, establishing September 2, 2005 as the date to file this report, due to FERC's action on August 10, 2005 to postpone the start of the LICAP market from January 1, 2006 to no sooner than October 1, 2006.

In this Interim Report the CEAB (1) presents a synopsis of the supply and demand status and outlook for the State; (2) describes the current and proposed market systems that will affect FMCC costs Connecticut consumers are expected to incur; and (3) offers recommendations on the types of measures the DPUC and others in the State could pursue to mitigate high FMCC costs, while assuring cost effective and reliable power supply.

For the purposes of this Report, the term "near term measures" refers to any measures that can be implemented by the DPUC, the electric distribution companies, or other entities in time to influence FMCCs expected upon implementation of LICAP and thereafter. The "near term" is also assumed to include the period 2006 through 2009, which coincides with the planned completion schedule of the Southwest Connecticut Reliability Project (Phases I and II of the Southwestern Connecticut transmission system).

3. Federally Mandated Congestion Charges

This section provides an overview of FMCCs and background on the wholesale power market. FMCCs influence electricity prices in Connecticut, and mitigating them is a focus of the DPUC's current inquiry.

FMCCs are a component of the costs that are associated with transmission system congestion. Congestion results from physical limits in the transmission system, restricting the free flow of economic power supply from generation to loads in Connecticut. The wholesale power market and regional transmission system are governed by federal regulation (the Federal Energy Regulatory Commission or FERC). Thus, the market rules and rate making policies that determine congestion charges are "federally mandated." ISO-NE began implementing FERC-authorized market rules associated with congestion in 2003. It is developing additional market rules and mechanisms pertaining to congestion for implementation in 2006.

The Energy Independence Act defines FMCCs as follows:

> *"Federally mandated congestion charges" means any cost approved by the Federal Energy Regulatory Commission as part of New England Standard Market Design including, but not limited to, locational marginal pricing, locational installed capacity payments, any cost approved by the Department of Public Utility Control to reduce federally mandated congestion charges in accordance with this section, sections 16-19ss, 16-32f, 16-50i, 16-50k, 16-50x, 16-244c, 16-244e, 16-245m and 16-245n, as amended by this act, and sections 8 to 17, inclusive, and 20 and 21 of this act and reliability must run contracts."*

3.1 Federal Energy Regulatory Commission and FMCCs

The federal regulatory approach to the nation's interstate power generation and transmission systems has been evolving from a fully regulated utility monopoly structure to more open, competitive generation markets for nearly 30 years. In 1978, the Public Utility Regulatory Policies Act ("PURPA") provided the opportunity for entities other than regulated utilities to own generation and sell electricity to third parties. In 1992, the Energy Policy Act established the legal framework for open access to the nation's transmission systems and the opportunity for the generation of power to be transacted at market-based rates.

In 1996, FERC established rules to implement the open access transmission provisions of the Energy Policy Act of 1992 and adopted a policy to encourage the formation of regional transmission groups to facilitate transmission access. In Order 2000, issued in December 1999, FERC established rules for the implemented a (non-locational) Forward Reserves market in December 2003, and it is planning to add a locational component in 2006.

3.3 Energy Market Congestion: Locational Marginal Pricing

Spot market energy prices in New England currently are based on LMPs, pursuant to FERC's standard market design policy.[4] Currently, there is one pricing zone in Connecticut, and seven other pricing zones throughout New England.[5] As noted above, LMPs have been operational in the ISO-NE market since March 2003.

FERC has ordered that Connecticut be divided into two LMP zones as of January 1, 2006, one zone in SWCT and one zone for the rest of the State.

At times, when transmission constraints restrict the free flow of power between Connecticut and the rest of New England, LMP prices in the Connecticut zone will differ from the other LMP prices in the region.[6] Absent transmission constraints – or, in other words, absent congestion – the most economical power plants in the region generate electricity. Congestion costs are the result of the need to utilize higher cost local generation when transmission limitations preclude lower cost power from being imported from other zones.

Because of congestion, zonal LMPs in Connecticut have been slightly higher on average than in other pricing zones of New England. Table 3.1 presents ISO-NE's data on zonal LMP prices in New England in 2004. It shows Connecticut's annual average real time price of $52.80/MWh to be 1.3% higher than that of the New England Hub (a reference price internal to the ISO-NE control area). The day-ahead prices are slightly higher (3%) in both the Connecticut zone and the New England Hub. The minimum and maximum hourly prices demonstrate that in individual hours, the LMP prices can vary substantially from the annual average price.

In most hours of the year, Connecticut's zonal LMP prices have not been materially affected by congestion. From July 2004 through June 2005, 50% of the hourly prices in the Connecticut zone were

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4 "Spot market" is used here to refer to both the day-ahead and real time LMP markets.

5 These pricing zones determine the prices paid by load serving entities for energy purchased in the spot market to serve load. Prices in each zone are an average of a number of pricing nodes within each zone. Energy produced by generation and sold in the spot market is paid the nodal price applicable to its location. As Docket No. 05-07-14 is assessing measures to mitigate FMCCs to consumers, this discussion focuses on the zonal pricing applicable to consumers.

6 Line losses also create differences in the LMPs experienced in different zones across the region (i.e., even when there are no transmission constraints).

in the July 2004 to June 2005 period. Some statistics on the price variances illustrate the nature of the congestion in that 12-month period:

Connecticut prices were higher than Hub prices:

- in 5180 hours (59%)
- by more than $5.00/MWh in 415 hours (4.7%)
- by more than $25.00/MWh in 79 hours (0.9%)

Connecticut prices were lower than Hub prices:

- in 3459 hours (39.5%)
- by more than $5.00/MWh in 32 hours (0.4%)

These statistics indicate that there are few hours in which energy prices are materially increased because of congestion. Those are concentrated in the hours when very high Connecticut demand and/or significant outages of Connecticut generation cause transmission import limits to be reached. Conversely, there are many hours in which Connecticut has economic power supply that cannot be exported. This results in a significant number of hours when Connecticut LMP prices are somewhat lower than those of the New England Hub.

The above data are not necessarily indicative of the LMP prices that would have existed in a SWCT Zone. In 2004, nodal prices in the Stamford/Norwalk sub-area averaged higher than the zonal prices for the State and region. However, such differences between SWCT and the rest of the State will be tempered when the Bethel-Norwalk 345 kV transmission line is completed (currently scheduled for December 2006).

While the form and timing of a locational capacity market is not entirely clear, it is clear that the FERC and ISO-NE intend to implement changes to capacity markets. FERC has opined that RMR agreements, discussed in Section 3.6, are an inappropriate remedy for reliability concerns. FERC ordered ISO-NE to design and file for approval a system to pay different prices for capacity in zones where transmission limitations and lack of local supply have necessitated non-market-based solutions (such as RMR contracts). The stated intent of the LICAP system was to provide locational capacity prices to encourage construction of new generation where and when it is needed.

Should it be implemented, the LICAP system would introduce two significant changes. First, there would be a downward sloping demand curve in the capacity spot market, which would result in different capacity "clearing" prices depending upon the total amount of capacity participating in the auction. Second, there would be an adjustment of the Capacity Obligation of each load serving entity, such that the total amount of capacity supported (that is, paid for) equals total available supply, even if it exceeds the Capacity Obligation.

An important characteristic of the LICAP market is that it is a residual market. It is designed to be a spot market that will set the price for any capacity not previously secured contractually. Buyers and sellers are free to enter "bilateral" contracts for capacity at mutually agreeable terms and conditions. Only buyers, referred to as load serving entities ("LSEs"), that have not contracted for capacity in advance will pay the LICAP clearing price; and only those generators without contracts will receive the LICAP clearing price. The contractual buyers and sellers of capacity will continue to transact at the contract prices. The ability to contract for capacity rather than pay the LICAP (spot market) clearing prices means that the LICAP market can be hedged. For purposes of this Report, it is assumed that costs under any such capacity contract would qualify as FMCCs, as the contracts would serve to hedge the LICAP market. However, as with any contract, its costs cannot be avoided while the contract is in force.

3.5 Ancillary Services Markets Congestion: Locational Reserve Market

As with capacity markets, New England's Ancillary Services Markets ("ASMs") are not currently locational. FERC has ordered consideration of other changes to ISO-NE markets which may affect Connecticut and the future FMCCs paid by Connecticut consumers. One aspect of this is the plans for the addition of a locational component to the forward reserves market.

In addition to energy and installed capacity markets, ISO-NE operates ASMs for operating reserves and regulation. Generating facilities that can offer to stand ready to increase production within 10 or 30 minutes notice are needed to enable the system to respond to unforeseen changes in load and unit outages. In addition, generating facilities that can provide second-to-second variation in output though Automated Generation Control ("AGC") are needed to regulate frequencies in the power supply system.

In early 2003, ISO-NE and NRG requested FERC approval of four RMR agreements,[9] based on a need determination associated with reliability requirements of SWCT and Connecticut as a whole. In April 2003, FERC concluded that flaws existed in the capacity markets, but rejected the proposed RMR agreements. Instead, FERC created a Peaking Unit Safe Harbor ("PUSH") mechanism to provide low capacity factor generating units in designated congestion areas an opportunity to recover their fixed costs through the market.[10] At the same time, FERC ordered ISO-NE to file a proposal to establish a permanent capacity market mechanism for locational capacity by March 2004 for implementation in June 2004. The PUSH mechanism was to end when the locational capacity market was implemented.

In June 2004, FERC directed ISO-NE to modify its LICAP proposal and delayed the implementation target date from June 2004 to January 2006. With this delay, FERC received and approved certain RMR contracts. Similar to the PUSH mechanism, the RMR contracts were to be interim mechanisms and to end upon implementation of the LICAP system. RMR contracts were provided to generation units deemed necessary, but which either performed poorly under PUSH or were ineligible for PUSH. The RMR contracts are designed to provide "cost of service" compensation, net of energy revenues obtained in the LMP energy market.

To date, eight sets of RMR contracts have been established with the owners of Connecticut generating stations and eight sets of Connecticut generating units operate under PUSH. The seven sets of RMR contract sets that are currently effective (i.e., "effective with final FERC approval" as of July 27, 2005) are identified in Table 3.2, as are the eight sets of PUSH units. ISO-NE reports that an eighth set of RMR contracts with NRG for its Devon Units 7 and 8 terminated in 2004.

The RMR arrangements are expected to continue until the LICAP system is implemented. In light of FERC's decision to implement LICAP no sooner than October 2006 (and pending resolution of the locational capacity market implementation), the agreements are expected to operate through at least September 2006.

Localized reliability assessments that ISO-NE may consider in determining the need for RMR contracts can include:

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9 The four NRG contracts were for units at its Devon, Middletown, Montville, and Norwalk facilities, representing 1,728 MW of capacity.

10 ISO-NE reports that, on June 1, 2003, it implemented Peaking Unit Safe Harbor (PUSH) offer rules, allowing owners of low capacity-factor units (less than 10% annual capacity factor) in Designated Congestion Areas (DCAs) to include levelized fixed costs in their energy offers without risk of mitigation. The rules were intended to increase opportunities for fixed cost recovery and to produce signals for investment through higher LMPs in these areas during periods of scarcity. This temporary revision of the ISO's mitigation rules is to remain in effect until it is replaced by a LICAP market, deliverability requirement, or similar modifications to the existing New England capacity market.

Table 3.2 - Summary of Connecticut PUSH and RMR Units

Owner/Unit	MW	Type
NRG Devon 11-14	121	RMR
NRG Middletown 2-4,10	770	RMR
NRG Montville 5,6,10,11	494	RMR
PSEG New Haven Harbor	448	RMR
PSEG Bridgeport Hbr. 2	130	RMR
Milford Power LLC	493	RMR
Bridgeport Energy	451	RMR
South Meadow 11-14	149	PUSH
Branford 10	16	PUSH
Cos Cob 11-13	55	PUSH
Torrington Terminal 10	16	PUSH
Franklin Drive	15	PUSH
Bridgeport Harbor 4	10	PUSH
Tunnel 10	16	PUSH
Middletown 10	*	PUSH
Totals	3184	

* Middletown 10 capacity already included in RMP capacity above.

During 2005, FERC has approved additional generating units for RMR treatment. Based on RMR contracts currently in effect, fixed RMR payments to Connecticut generators alone in 2005 will reach nearly $300 million, with a net cost to consumers (i.e., net of energy revenues) of about $230 million. In the event that FERC is persuaded that these contracts must be maintained to preserve reliability even after the LICAP market takes effect, Connecticut consumers would incur a like amount of RMR costs during 2006, as well.

Table 3.3 2004 RMR-ORC Payments by Sub-Area

Sub-Area	Day-Ahead	Real-Time	Total
Stamford/Norwalk	$5,955,780	$16,591,505	$22,547,285
Southwest Connecticut	$322,735	$1,315,412	$1,638,147
Rest of Connecticut	$0	$5,147,579	$5,147,579
Total CT	$6,278,515	$23,054,496	$29,333,011
Total NEMA-Boston			$16,084,893
TOTAL ISO-NE			$45,417,904

Source: ISO NE *2004 Annual Markets Report*
Note: Economic ORC payments of $45.5 million not included.

3.7 Cost Recovery of FMCCs

The FMCC's incurred by Connecticut's electric distribution companies are categorized as bypassable (i.e., avoidable/energy related) and non-bypassable (i.e., unavoidable/ reliability related). Bypassable FMCCs generally include the costs associated with transitional standard offers and congestion risk mitigation. Non-bypassable FMCCs generally include RMR, SWCT energy resources and other ISO-related costs. Both cost categories are subject to change over time. The following tables provide a list of currently approved FMCC costs, which are reflected in the electric distribution companies' tariffs:[13]

[13] DPUC Final Decision in Docket No. 04-03-19, dated November 24, 2004.

FMCCs generally are passed on to customers through a DPUC-approved rate adjustment mechanism. The electric distribution companies can seek DPUC approval to recover any new FMCC costs, such as those that may be created in the course of implementing the Act Concerning Energy Independence, in semi-annual FMCC reconciliation proceedings. The DPUC has found that, while the filed rate doctrine limits state regulatory review of wholesale power costs, it does not eliminate state jurisdiction altogether. Accordingly, the DPUC maintains that, although many FMCC-related fact patterns preclude state inquiry, there may be scenarios in which state review of FMCC costs would not interfere with FERC regulation. Moreover, FMCCs generally are subject to Conn. Gen. Stat. §§ 16-19b(c) and 16-19e(a)(5), both of which require the level and structure of rates to reflect prudent and efficient management.[14]

The electric distribution companies cannot control all FMCC costs, but there are strategies and tools through which they can manage price fluctuations and mitigate some of the FMCCs on behalf of ratepayers. For example, United Illuminating's ("UI") transitional standard offer ("TSO") supplier provides a fixed price contract, and is thus responsible for all directly related FMCC related costs.[15] This TSO structure insulates UI's customers from the risk of bypassable FMCC price increases over the TSO period as those costs are assumed by the supplier and factored into its bid price. By contrast, Connecticut Light & Power ("CL&P") purchases its TSO supply under contracts structured differently, such that the TSO contract may not include congestion costs. CL&P also flows through to customers the costs and revenues associated with Financial Transmission Rights and Auction Revenue Rights, which can be used to hedge FMCCs.

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[14] DPUC Final Decision in Docket No. 04-03-19, dated November 24, 2004.

[15] UI customers are not necessarily protected from all FMCC costs. UI may still be responsible for RMR charges allocated to UI by ISO-NE.

3) Planning Criteria and Standards

Reliability planning criteria, standards and analysis are conducted by ISO-NE. The ISO routinely conducts its reliability assessments to be consistent with nationally accepted reliability standards. Many of the specific parameters are established through the application of planning models and assumptions. Parameters that affect the requirements in Connecticut include Objective Capability (sometimes known as "Installed Capacity"), Operable Capacity, Operating Reserves requirements, and Import Limits. Each of these criteria is established and updated in a market participant stakeholder process administered by ISO-NE. Transmission planning, load forecasts and reliability planning studies and assumptions are used in this stakeholder process. Policy choices included in this process can have a material affect on the requirements for Connecticut. For example, ISO-NE has just initiated a two-year stakeholder process to do a comprehensive review of the methods used to set the Installed Capacity requirements, a key parameter in the proposed LICAP pricing system.

4. Connecticut's Electric Supply and Demand Status

On July 19, 2005, hot and humid weather drove demand for electricity in New England to record levels. New England's peak demand reached 26,749 MW, exceeding the prior record set in August 2002 by 1,400 MW. A Connecticut peak demand load of 7,065 MW was 50 MW higher than the previous high set in July 2003.

Eight days later, hot and humid weather returned, driving peak demand for electricity to new record levels, with regional demand reaching 26,922 MW and Connecticut demand reaching about 7,150 MW. On that day, demand stressed the limits of the power system, causing ISO-NE to invoke emergency measures in Southwest Connecticut to avoid the loss of load. These measures included calling on emergency supplies and demand reduction contracts, and issuing appeals for voluntary conservation, thereby reducing what otherwise would have been an even greater demand for power.

These extreme demands on the power system are driven largely by customer air conditioning loads, which are at a maximum during hot, humid weather. In response to peak demand conditions, ISO-NE calls into service all available generation in the State and region, transmission imports are increased to maximum possible levels, and transmission lines are fully loaded. It is at these times that the overall reliability of the system is most vulnerable to unplanned outages of key generation and transmission elements.

Events such as these are the measure of the electric system's reliability. They also are key contributors to FMCCs because load forecasts that anticipate such events are central to planning for investment in new transmission and generation facilities. Power systems are planned to meet the pertinent standards for system reliability. Hence, in order to assess whether one has sufficient resources – which means amount and type, properly located – the key question is: What are the reliability planning standards?

The CEAB has reviewed loads and resource information prepared by ISO-NE and the Connecticut electric distribution companies, as well as the measures of system reliability used by ISO-NE to determine system requirements. This section provides a synopsis of the load forecast, the demand, supply and transmission resources, and assessments of the supply/demand balance in the context of the measures of reliability.

2) Connecticut's Energy Requirements

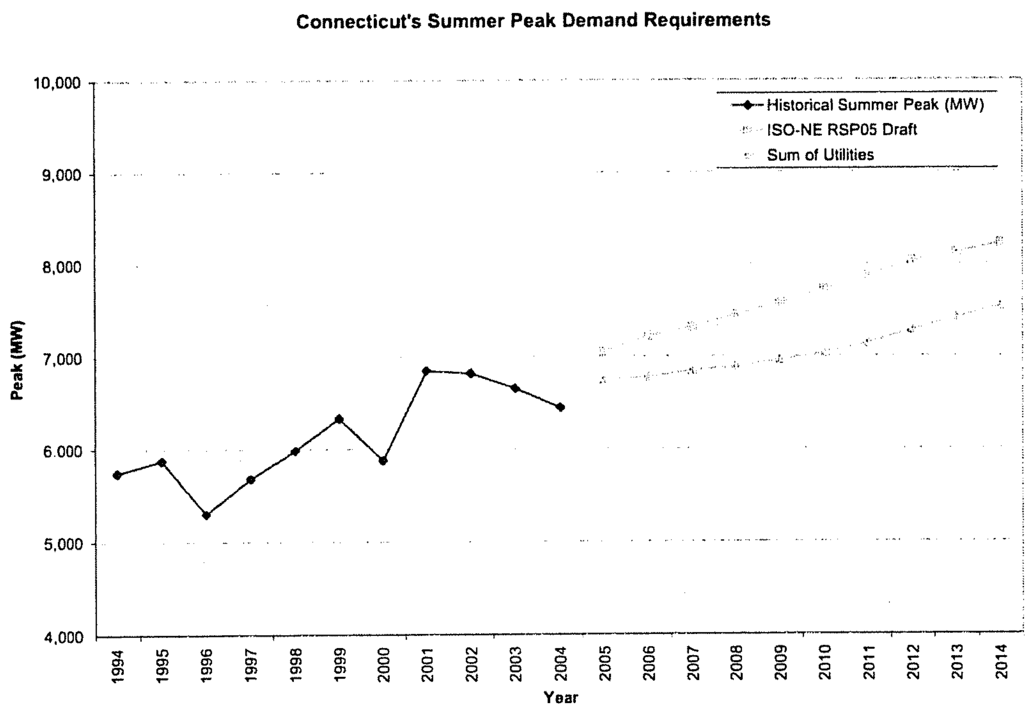
Electric energy requirements for Connecticut have grown steadily across the last decade. Data from ISO-NE indicate that energy usage in the State has increased at an average annual compound rate of 1.2% from 1994 through 2004, reaching 34,171 GWH in 2004. The growth rate in recent years has exceeded that ten-year average. For example, across the three years 2001 to 2004, Connecticut's energy usage increased at an average annual compound rate of 1.6%. In recent years, the rate of growth in energy requirements for the State has been about the same as that of New England as a whole.

ISO-NE forecasts that Connecticut's energy requirements will increase to 34,620 GWH in 2005, and will grow thereafter at a 1.8% average compound annual growth rate to 40,500 in 2014. This rate is somewhat higher than its corresponding growth rate for New England (i.e., 1.5%).

According to the Sum of the Utilities forecast, by contrast, Connecticut's energy requirements will increase to 34,037 GWH in 2005, and then will grow at a 1.3% average compound annual growth rate to 38,186 GWH in 2014.

The electric distribution companies' forecasted growth rate for Connecticut is obviously lower than ISO-NE's corresponding forecast (1.3% versus 1.8%); in addition, their growth rate is lower than that forecast by ISO-NE for New England (1.3% versus 1.5%). Figure 4.1 compares the history (actual) and projected energy consumption in Connecticut, where the forecasted data are from the ISO-NE and Sum of the Utilities forecasts of energy requirements.

Figure 4.2



As noted above, two forecasts of Connecticut's peak demand requirements were utilized in assessing the State's future capacity needs: the ISO-NE and Sum of the Utilities forecasts. ISO-NE forecasts that Connecticut's peak demand requirements will increase to 7,055 MW in 2005 and, thereafter, grow at a 1.7% average compound annual growth rate to 8,305 MW in 2014. This rate is somewhat higher than ISO-NE's corresponding growth rate for New England (i.e., 1.5%).

In addition, ISO-NE prepared ten year forecasts of zonal peak demand projections and documented the results in a report entitled "2005 CELT & RSP Forecast Detail: ISO-NE control area and LICAP Zones." Evidently, to develop these zonal forecasts, ISO-NE collected the FERC 715 filings for CL&P, UI, and CMEEC, which detailed bus level load and energy projections. According to the ISO-NE's forecast, the (summer) compound annual average peak load growth rates for the ten-year planning period are 1.5% for SWCT, and 1.9% for the ROC zone.

According to the Sum of the Utilities forecast, by contrast, Connecticut's peak demand requirements (net of DSM) will increase to 6,744 MW in 2005, and then grow at a lower 1.25% average compound annual growth rate to 7,545 MW in 2014. This rate is also somewhat lower than ISO-NE's corresponding

The foregoing details regarding the various approaches to both energy and peak load forecasting matter substantially. The difference in the forecasts can have major implications for resource planning. As shown in Table 4.2, the projected difference of over 300 MW in 2005 grows to a nearly 750 MW difference by 2012.

4) Connecticut's Customer Classes and End Uses

Electric service in Connecticut is provided primarily to customers classified as residential, commercial, or industrial. Approximately 40% of total energy sales are consumed by residential customers, 38% by commercial customers, 15% by industrial customers, and 7% by other customers such as street lighting customers and railroads.

Peak demand levels in Connecticut are a direct function of the customer end-uses served by the State's electric distribution companies. A breakdown of summer peak demand by class and end-use is presented in Table 4.1. Note that loads by specific end-use are not available for the industrial class; therefore, all industrial loads are included in the row designated as "Other."

At present, over 40% of Connecticut's peak loads are driven by cooling requirements, which shows that summer air conditioning is a significant force behind the State's need for incremental capacity resources. This is important relative to the peak load reduction strategies that might be considered to mitigate FMCCs.

Table 4.1
Summer Peak Proportions by End-Use
Source: CL&P

End-Use 2005	Residential	Commercial	Industrial	Other	Total
Cooling	23%	18%	0%	0%	40%
Lighting	1%	10%	0%	0%	11%
Other	20%	17%	11%	0%	49%
Total	44%	44%	11%	0%	100%

temperatures at the time of system peak, the weather-adjusted value for July 27 falls into line (to within a fraction of a percent) with the forecast value.

capacity savings from existing demand-side program measures; however, neither provided a forecast of specific savings levels from such measures.[19]

2. Planned CLM Program Savings

CL&P provided forecast estimates of the likely capacity savings from its various CLM programs, from measures that would be implemented beginning on January 1, 2005. Several items merit attention in this regard. First, the initial estimates submitted to the Siting Council (i.e., with CL&P's March 1, 2005 filing) reflected only capacity savings from measures that were included in its proposed 2005 budget. The DPUC approved a considerably larger 2005 budget later this spring. Therefore, CL&P provided revised incremental savings estimates to reflect consequent, foreseeable increases in capacity savings levels.[20]

Second, CL&P noted its capacity savings estimates assume that programs being implemented during the budget year (i.e., 2005) would continue for five years, and would produce incremental savings from one year to the next. Savings from installed measures are assumed to persist throughout an estimated "life" for each measure. The measures and their capacity savings are assumed to expire at the end of the measure's life.

UI and CMEEC did not provide separate forecasts of the capacity savings expected from demand-side program measures to be installed during the term of their load forecasts. It appears, but is not entirely clear, that such planned savings levels are implicit in their forecasts. If not, further capacity savings reductions should be recognized in a thorough accounting of loads and resources.

It is important to establish to what degree capacity savings estimates are included in ISO-NE's forecast of peak loads for Connecticut (i.e., for each of the State's load zones) as presented in the supporting documentation to the 2005 CELT Report and used in the Draft RSP05 report. To date, it has not been possible to ascertain that information. The 2005 CELT forecast makes clear that ISO-NE's "adjusted, reference case" peak load forecast is reduced relative to the "unadjusted" forecast as a consequence of demand-side program savings. Thus, the ISO-NE peak load forecast for Connecticut appears to be a direct function of its peak load forecast for the region. As such, while it might be reasonable to assume that Connecticut's share of the New England region's demand-side capacity savings (which are explicit in the 2005 CELT Report) follows that same ratio, this is not now known for certain. Nor is it clear what level of Connecticut demand-side capacity savings were factored into the 2005 CELT Report projections. While it appears that the electric distribution companies share their projections of

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19 UI filed with the CSC a forecast of future conservation program savings that combines savings from current and projected CLM measures.

20 Note that the Energy Conservation Management Board recently filed goals for CLM programs for 2005 that reflect revised savings estimates, in keeping with the approved 2005 electric distribution company budgets.

equipment that result in decreased energy use while maintaining the same or improved levels of energy service.

The June 2004 ECMB study indicates that there is significant savings potential in Connecticut for the implementation of additional energy efficiency measures. By its estimate, capturing the maximum achievable cost-effective potential for such measures would reduce peak load by 13% (i.e., 908 MW) by 2012 and, in effect, eliminate growth in peak load through 2012. In any event, whether or not all of the foregoing is achievable, the savings possibilities are substantial. In addition, the potential capacity savings from load management and load response measures were not included in the ECMB study. Thus, investments in such programs are likely to be an opportunity to obtain even more capacity savings for Connecticut.

4.3 Connecticut Supply Resources

Connecticut has substantial existing generating resources. Based on summer claimed capabilities, as summarized by ISO-NE, 6,774 MW of operable generating capacity is installed within state borders. Of this total, only 2,376 MW is located in SWCT. Connecticut's generation base is augmented by various supplies, including: (1) roughly 212 MW from the deactivated units Devon 7 and 8, which evidently qualify as installed capacity under the rules of ISO-NE's installed capacity (and LICAP) markets; (2) roughly 250 MW from the GAP RFP, which established contractual rights to this capacity through the year 2008; and (3) another 40 MW, or more, that result from other demand response programs implemented by ISO-NE.[23]

Connecticut's capacity resources consume a variety of fuels, including uranium, coal, oil, natural gas, landfill gas, and biomass. Connecticut also has a number of hydropower facilities. The Millstone 2 and 3 nuclear units are a substantial portion of the State's baseload supply, totaling 2,037 MW. Other baseload facilities include Bridgeport Harbor 3 (372 MW) and AES Thames (182 MW). Various hydropower facilities deliver another 150 MW in baseload generation, bringing the State's baseload total to 2,741 MW, or about 40% of installed capacity.

A number of new generating facilities have entered the Connecticut supply mix in recent years. Baseload / intermediate units include the Lake Road facility (693 MW), Milford Power 1 and 2 (492 MW), Bridgeport Energy (451 MW), Bridgeport RESCO. Peaking unit additions include Wallingford Power (220 MW), Devon 11 through 14, (120 MW), and Norwalk Harbor 10 (11 MW). This 1,350-plus MW of new generation has dramatically improved the State's supply situation, but concerns remain.

[23] These demand-side resources are credited as "capacity" by ISO-NE in its calculations determining capacity cost obligations under LICAP.

Transmission infrastructure plays an important role in Connecticut's energy picture. The total installed capacity in Connecticut (6,774 MW) is very close to the level required to serve customer peak demands (actual peak loads were 6,444 MW in 2004 and roughly 7,150 MW in 2005). As such, transmission becomes a critical resource, particularly during periods of high demand. In addition to ensuring access to economical generation, when the transmission infrastructure is adequate, it also enables a response to contingencies such as unforeseen generation outages, that otherwise could lead to a loss of load.

Investments in new transmission have been undertaken or are being planned to improve reliability and to mitigate exposure to FMCCs. The Southwest Connecticut Reliability Project (Phases I and II) improves power transfer capabilities into SWCT and overall transmission system performance. The impact of the completion of Phase I (the Bethel-Norwalk 345 kV project) in 2007 will increase transmission import capability into SWCT by 275 MW. Once Phase II (the Middletown-Norwalk 345 kV project) is completed in December 2009, the combination of the Phase I and II improvements will increase the transmission transfer capability into SWCT by 575 MW. It is important to note that neither Phase I nor Phase II significantly affect transmission capacity into Connecticut as a whole, as the improvements focus on in-State transmission infrastructure.

Other transmission improvements will affect Connecticut's import capabilities. These include (1) the Mystic, Connecticut to Wood River, Rhode Island 115 kV reconductoring, which will increase Connecticut's import capability by 150 MW in 2007, and (2) the SNERP project, which would substantially increase transmission into the State. However, the SNERP project is still being studied, and is not expected to enter commercial service until at least 2011.

With respect to capacity imports, note that New England's capacity market has had surplus capacity across much of the last decade; hence, the present transmission constraints preclude the import of some less costly power from outside Connecticut. There are, however, strong signs that the surplus may be abating. At present, few new generation projects in the region are being advanced beyond initial, low cost developmental milestones. ISO-NE forecasts of system requirements and capability suggest that the region may begin to experience capacity deficiencies within the next several years. The ISO indicates that, under its 50/50 load forecast, New England could experience a negative operable capacity margin of approximately 160 MW beginning in 2008, increasing to 2,600 MW by the summer of 2014. Under its 90/10 load forecast, New England could experience a negative operable capacity margin of roughly 1,070 MW beginning in 2006 increasing to 4,470 MW by the summer of 2014. The upshot is this: the value to Connecticut of an improved interstate transmission infrastructure cannot be assessed without a reasonable view of the conditions in the external markets into which in-State generation resources might sell and from which in-State loads might buy.

ISO-NE also looks at other measures of system reliability, including, for example, voltage regulation. For purposes of assessing FMCC exposures, Resource Adequacy, Operable Capacity, and Operating Reserves assessments are most relevant to Connecticut at this juncture. The following is a review of these measures as they pertain to this assessment of FMCCs.

It is important to note that the scenarios examined assume that, in the near term, all existing generation in Connecticut remains available and contributes to the supplies needed to maintain reliability.

1) Resource Adequacy

Appendix 1 contains the results of a series of calculations to forecast Objective Capability (OC), based on information on Connecticut loads and resources as described above. This analysis shows that across the near-term planning horizon extending through 2009, Connecticut (taken as a whole), and the SWCT and ROC zones (taken individually) will have sufficient resources to meet their OC requirements, as would be calculated under ISO-NE's proposed LICAP market. This is the case regardless of whether one utilizes the ISO-NE forecast or the Sum of the Utilities forecast, as described earlier. Obviously, the extent to which the OC standard is exceeded depends, in the first place, on which forecast is utilized to project future OC requirements.

The charts in Appendix 1 identify (1) the degree to which local capacity markets are forecast to be in a surplus condition, and (2) the level of incremental resources that would be necessary to resolve any deficiencies necessary to bring the zone into compliance with (a) OC, (b) a zonal capacity target established at 1.038 times OC, and (c) 1.15 times OC, each of which is relevant if the ISO-NE LICAP proposal is implemented in its present form.[25]

These analyses indicate that, under ISO-NE load forecast assumptions, Connecticut meets or exceeds the Objective Capability in all years. The LICAP formula includes prices for capacity to be paid on a sliding scale until Connecticut reaches a supply level of 115% of the Objective Capability.

ISO-NE plans to begin a stakeholder process within the next few months to re-evaluate the appropriateness of the current methodology in the current deregulated market environment, and discuss possible modifications or alternatives.[26]

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[25] ISO-NE's proposed LICAP demand curve establishes that capacity prices would (1) correspond to twice the costs of a peaking unit if a zone's capacity level equals OC, (2) correspond to the cost of a peaking unit if a zone's capacity level equal 1.038 times OC, and (3) fall to zero if a zone's capacity level is 1.15 times OC.

[26] See March 21, 2005 ISO-NE Filing to FERC in Docket ER05-715-000; 2005/2006 Power Year Installed Capacity Requirements (Objective Capability Values), n.11, page 7 and Section 6.2.1 of RTEP 04.

5. Anticipated Near Term FMCC Costs

As described in Section 3, FMCCs derive from several market and out-of-market mechanisms which include the following:

1. Locational Energy Market;
2. Locational Capacity Market (pending implementation);
3. Locational Ancillary Services (pending implementation); and
4. Out-of-Market Costs, including
   a) Reliability Must Run Contracts; and
   b) Operating Reserve Credits.

Of these components, the costs related to the capacity market present the largest potential FMCC exposure for Connecticut consumers. There have been a number of estimates – which vary widely – of the costs that the region would face if the LICAP spot market is implemented. For example, estimates of five-year added costs to the region ranging from $2.3 billion to over $14 billion have been presented in FERC proceedings. CL&P presented an analysis of Connecticut costs to the Siting Council in July 2005 in Docket F-2005 which estimates annual costs to Connecticut of $587 to $796 million. RMR contract costs, also a capacity-related cost, were $121.8 million in 2004[27] and likely will be nearly $300 million in 2005 given the additional contracts that were approved by FERC.

Other FMCC components are significant, as well. However, the order of magnitude of these components is less than the $100 million-plus range that capacity costs represent. For example, ISO-NE reports that Connecticut's costs for Operating Reserves for 2004 to be nearly $40 million.[28]

In this context, this assessment focuses on the potential costs of LICAP, if implemented, and the exposure to RMR contract costs. Issues associated with exposures to other components of FMCC's are also discussed.

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27 This figure presents the annual fixed costs of RMR contracts, prior to any energy offsets. See ISO New England *2004 Annual Market Report*, Table 29.

28 See ISO New England *2004 Annual Report*, Figure 6.4.

From this illustration, it is apparent that the LICAP costs can be very large and that one or two major additions can substantially reduce that cost. Indeed, particularly in some areas of the LICAP curve, prices can be quite sensitive to even small changes in supply. As an example of the effect of a major supply change, the addition of a 480 MW combined cycle unit (roughly equivalent to the new facility at Milford) can result in a substantial difference in the price and cost under this formula.

The CEAB conducted a review of the CL&P model and prepared some alternative scenarios, based on updated information. The scenarios tested different inputs and compared the results to those produced by CL&P (a description of these scenarios and results can be found in Appendix 2). The scenarios were as follows:

- Scenario CL&P OC: Retained the Installed Capacity targets utilized by CL&P under the updated assumptions reflecting recent capacity and transmission changes;
- Scenario Case 1 OC: Installed Capacity targets were updated in ROC and SWCT to reflect those used by ISO-NE in its Draft RSP05 report. These revised inputs correspond to the "Case 1" series of load projections from Appendix 1; and
- Scenario Case 2 OC: Installed Capacity targets were updated in ROC and SWCT to reflect peak load forecasted by Connecticut electric distribution companies. These revised OC inputs correspond to the "Case 2" series of load projections from Appendix 1.

Notable assumptions updates include the increase in current import limits into SWCT (up 300 MW) and into Connecticut (up 100 MW) and the inclusion of the Mystic-Wood River reconductoring effect on import limits (up 150 MW).

In addition, the CEAB modeled several strategies for mitigating LICAP costs to Connecticut. Each strategy was developed as a variation on both Scenarios Case 1 OC and Case 2 OC above. These included the following:

- Strategy X includes 100 MW of additional capacity (in the form of either load response or additional generating plant) to each of SWCT and ROC, beginning in June 2006;
- Strategy Y includes Devon 7 and 8 as LICAP resources in determining LICAP clearing prices for the 2006/2007 planning year; and
- Strategy Z includes a reduction in the peak load for SWCT (such as might be achieved through additional CLM measures) by summer 2006 (note that this load reduction would not affect LICAP calculations until the following summer).

A number of important observations can be made from the results of the modeling exercise. These are as follows:

4. Differences in Anticipated Contributions from ISO-NE Load Response Programs: Load response programs can alter a zone's supply that counts toward LICAP;
5. Differences in Anticipated Contributions from New Generation Resources; and
6. Differences in Counting Deactivated Generation Resources as a LICAP Resource: As noted earlier, deactivated generation can be recognized as LICAP capacity.

5.2 Outlook for Reliability Must Run Costs

Currently, Connecticut's capacity costs are tied to RMR contracts. These agreements were established by the FERC to ensure reliability until the LICAP market system is implemented. Because the FERC has delayed implementation of ISO-NW's LICAP market system, it is apparent that RMR contract costs will be a major component of Connecticut's capacity costs in 2006, and perhaps beyond.

At present, RMR agreements are in effect for units in Connecticut representing some 2,900 MW of capacity (listed in the Table 5-2). The fixed cost obligation, on an annualized basis, for these current agreements is about $300 million (fixed annual payments before netting of energy revenues). The need for these units derives primarily from Operable Capacity assessments conducted by ISO-NE. Based on the CEAB's assessment of that standard (as discussed in Section 4), the units may continue to be needed through the 2006 to 2008 period.

In the event that the LICAP pricing system is implemented, FERC policy on the use of RMR contracts is unclear. However, it is likely that special contracts, in some form, may continue to be needed with some of the units that now have RMR contracts. The concerns here include:

1. RMR contract need is based on Operable Capacity, which is a significantly more stringent criteria than the Installed Capacity requirement in Connecticut. On this basis, reliability need will continue through the near term.
2. The pricing terms for many of the current RMR contracts are high relative to many of the LICAP scenarios considered. It is unclear whether LICAP revenues will provide revenues sufficient to ensure that this capacity remains financially viable.

capability into Connecticut during summer peak conditions. This change will tend to reduce LMPs and other FMCCs throughout the State by reducing congestion and allowing increased access to less expensive energy and reserves elsewhere in New England.

The CEAB has not conducted any analysis of expected LMP levels during 2006-2008, and is not aware of studies of this type by ISO-NE or the Connecticut electric distribution companies. The level of LMPs will be affected by events in the marketplace, such as generation unit and transmission facility outages, load levels (particularly in the event of any extreme weather events), and any changes in the inventory of generation facilities in the market.

6. Cost/Benefit Assessment of FMCC Mitigation Measures

The Energy Independence Act requires the DPUC to identify measures by November 1, 2005 that can reduce FMCCs and can be implemented, in whole or in part, on or before January 1, 2006. These resources can include demand response, distributed resources, and contracts for capacity from generation resources.

In its implementation of Section 12(a) of the Act, the DPUC will be required to make a determination regarding the cost-effectiveness of measures proposed for implementation in 2006. This section offers an analytical framework to facilitate the DPUC's assessment of these near term measures.

6.1 General Considerations

As a general matter, the economic analysis of proposed measures should provide a basis to determine whether the cost of the measures are materially less than the FMCC costs that would otherwise be incurred by Connecticut consumers. Because of the near-term, compressed timeframe in which the Section 12(a) process must be implemented, the CEAB offers a simple screening approach as an analytical framework that will allow the DPUC to identify the best programs quickly.

A. Basic Approach

The primary focus of the measures to be implemented will be peak demand reduction and installed capacity that qualifies as Installed Capacity under ISO-NE's rules. The CEAB suggests that the recommended measures initially be ranked on a cost per kW-month basis, and then by resource and location preferences.

The cost per kW-month assessment is effectively an "avoided cost" approach, comparing the proposed measures to other alternative measures that could be implemented in lieu of the measure in question. The anticipated cost of the FMCC to be avoided would establish a ceiling price.

B. Consideration of Additional Avoided Cost Benefits

For those measures that offer benefits in addition to capacity in suitable locations, further analysis or assessment will be necessary. Additional benefits may include reduction of LMPs and associated energy congestions costs, reduced cost of operating reserves and associated uplift payments.

With the FERC's recent action to defer LICAP implementation, demand response and load management measures installed for the summer of 2006 would not affect LICAP costs until at least October 2006.

6.3 Distributed Resources

In addition to the demand response and load management measures, Distributed Resources, as defined in the Act, can include generation projects with a rating of not more than 65 MW and reductions in end-use consumption. A second screening level can be established for Distributed Resources that provide energy production or conservation benefits in addition to capacity or peak load management benefits.

Energy conservation programs should first be screened by impact on peak load and then by energy savings. Energy savings benefit can be conducted on an avoided cost basis.

Distributed Generation projects may require analysis of specific energy production and operating reserve attributes that may be available. Generation projects that qualify as quick start capability for operating reserves at ISO-NE should be given preference.

For purposes of the Section 12(a) assessment, generation projects will necessarily be limited to those that readily can comply with the interconnection protocols approved by the DPUC in Docket No. 03-01-15, <u>DPUC Investigation into the Need for Interconnection Standards for Distributed Generation</u>.

6.4 Additional Generation Resources

Generation resources other than those that qualify as distributed resources are expected to require project specific assessment of costs and benefits. Capacity, energy, operating reserve and interconnection aspects of the project should be considered on a project specific basis.

7. Location of Resources

The location of supply and demand resources within Connecticut will have a significant bearing on the extent to which FMCCs can be mitigated. Specific location requirements cannot be precisely defined at this time, particularly for grid-connected generation, because many project- and location-specific transmission considerations should be determined through project-specific assessments. However, general guidelines can be articulated. This section of the report describes several of the key considerations that affect the location preferences for FMCC mitigation measures within Connecticut.

7.1 Proximity to Load

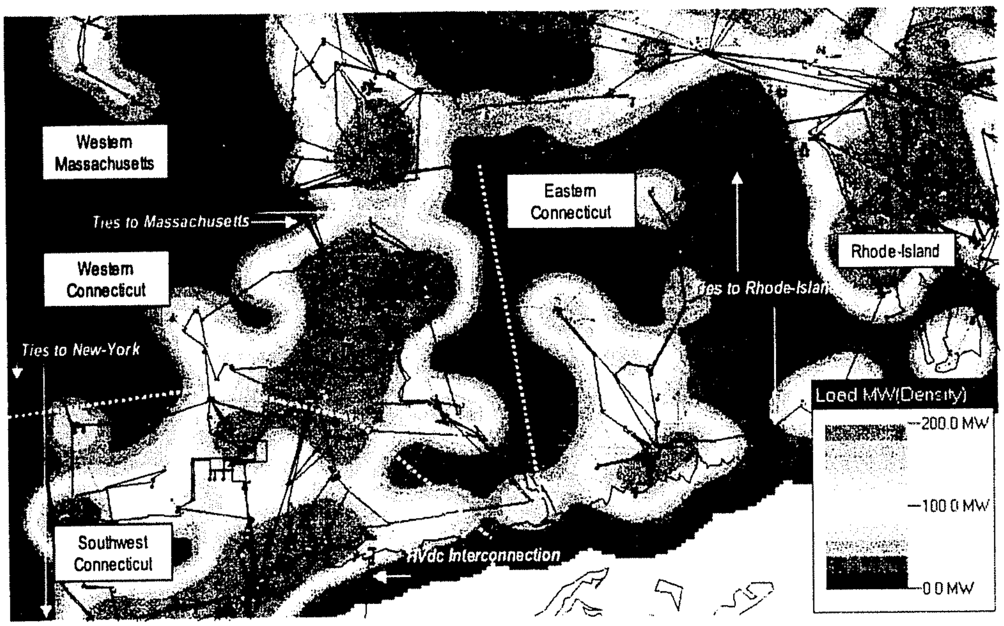
The simplest guideline is to locate resources close to load. This minimizes losses in the transmission system and requirements for power flows across transmission interfaces.

Conservation and load management measures have clear location-specific benefits. Reducing the volumes of power, particularly at times of system peak requirements (either regionally or locally) will, in turn, reduce the power transfer requirements that would otherwise be placed on the transmission system. Customer-sited generation, if sized such that it does not adversely affect transmission (or distribution) systems.

Beyond customer on-site load reduction resources, resources located in close proximity to load concentrations within Connecticut will generally be of high value in mitigating FMCCs. Figures 7-1 and 7-2 include ISO-NE graphic illustrations of load concentrations in New England and Connecticut, which shows the concentration of load along the coast in Southwest Connecticut and along the Connecticut River. Resources located in those portions of Connecticut are much more likely to have high value in mitigating FMCCs than in other locations in the State.

Figure 7-2

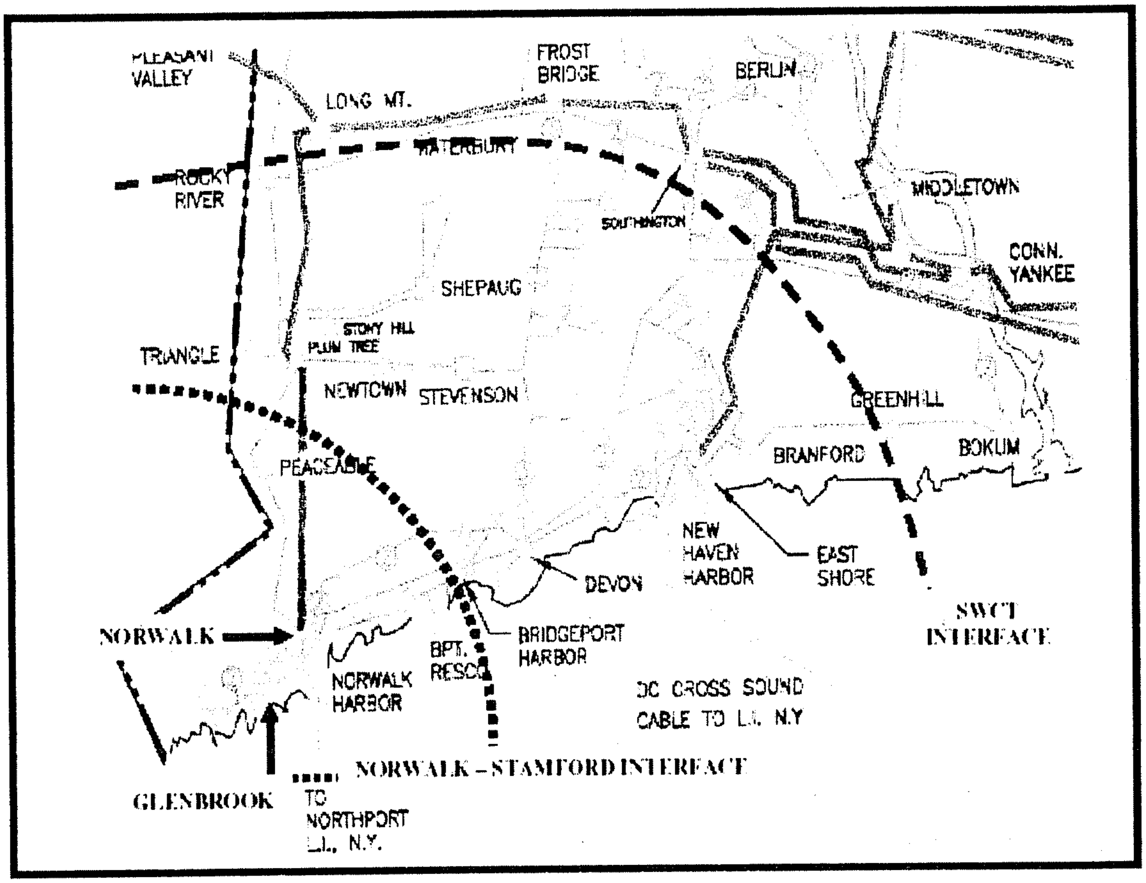
Load Concentrations in Connecticut



Source: ISO New England

Figure 7-2

Southwest Connecticut Transmission Interfaces



Source: ISO New England

8. Conclusions and Recommendations

Connecticut's exposure to FMCCs is substantial and multifaceted. ISO-NE's plans for locational capacity markets (now postponed to at least October 2006) and the potential for a two-zone energy market in Connecticut are important elements of the cost exposure. In addition, as discussed in Section 4, other system reliability criteria (such as OP CAP) will result in FMCCs to be borne by Connecticut's consumers. The RMR contracts are perhaps the most obvious example.

The Phase I and Phase II transmission projects will mitigate some of the FMCCs. However, even after the implementation of both projects, significant transmission constraints – both interstate and intrastate – and associated FMCCs will remain. The ways to mitigate the FMCCs will include measures that affect peak demand, as well as generation and additional transmission resources. The CEAB's recommendations regarding these resources are discussed below in Sections 8.1-8.5.

The CEAB's preliminary assessment of Connecticut's current electric system and the near-term outlook for loads, supplies, transmission and FMCCs leads to the following observations:

1. 2006 FMCC exposures will be most acute in Southwest Connecticut. ISO-NE plans to implement a distinct energy pricing zone in that area in January. Reliability Must Run and Operating Reserve costs will likely remain high in that area through 2006. The Bethel-Norwalk transmission line is not slated for operation until year-end 2006. Near term actions should concentrate in this area, particularly in the Stamford/Norwalk sub-area, to have maximum benefit to Southwest Connecticut and the State as a whole.

2. At this juncture, to the CEAB's knowledge, neither ISO-NE nor the Connecticut electric distribution companies have definitive studies that would provide the information needed for more targeted locations for distributed resources.

3. Significant FMCC exposures will remain in 2007 and 2008, although the completion of the Bethel-Norwalk transmission line is expected to temper the exposure, particularly in Southwest Connecticut, by increasing intra-state transfer capabilities.

4. The level of FMCCs in the 2006 to 2008 period is very sensitive to peak load levels. Forecasts of peak load, net of CLM contributions, from ISO-NE and the Connecticut electric distribution companies differ materially and have very different implications for the State's resource requirements, as lower peak loads will translate in to lower FMCCs.

5. Congestion and FMCCs are significantly determined by usage in peak load or near peak load conditions and during times when significant amounts of local generation are out of service.

A. ECMB/Utility Conservation and Load Management Measures

The *Energy Independence Act* requires the ECMB to give preference to programs that maximize the reduction of FMCCs. The CEAB's preliminary assessment of mitigation opportunities for FMCC indicates that this preference should be directed to:

1. Programs that qualify for ISO-NE's Real Time Demand Response program, that is, that provide Installed Capacity credit;

2. Programs that qualify for ISO-NE's Real Time Price Response or Profiled Response programs;

3. Programs that are targeted to reduce peak load; and

4. Energy efficiency programs that have a high coincidence factor with peak demand.

To maximize FMCC mitigation, the CEAB recommends that support for programs, such as load response programs and the Price Response Supplemental Payment Pilot Program, be increased materially in the near term, albeit subject to review of the available 2005 data. The CEAB recognizes that the dedication of conservation fund dollars in this manner may be a departure from programs that may be preferred in other circumstances. Nonetheless, current circumstances warrant a strong near term commitment to load response.

Locational preference should be given to those measures that can be implemented in the Stamford/Norwalk sub-area to have the maximum effect on reduction on energy congestion and operating reserves. Measures implemented in other locations in the Southwest Connecticut zone will also provide substantial benefits. As a general matter, measures implemented in all locations in Connecticut will provide benefits in mitigating LICAP costs, although if ranked by their respective benefits and costs, near term implementation will tend to favor Southwest Connecticut.

B. Rate Design

The *Energy Independence Act* recognized the potential for rate design to contribute to demand reduction and FMCC mitigation. Specifically, Section 13 of the Act requires that the DPUC consider rate design adjustments including: mandatory peak, shoulder, and off-peak time of use (TOU) rates for customers with a maximum demand of not less than 350 kW on or before January 1, 2007 (subject to a TOU exemption option to be determined by the DPUC); optional interruptible or load response rates for customers that have a maximum demand of not less than 350 kW; and optional seasonal and TOU rates for all customers on or before June 1, 2006. The Act also contemplates mandatory seasonal rates for all customers beginning April 1, 2007.

providers and ISO-NE, there are a number of issues that would need to be resolved in order to effectuate any contractual changes.

The CEAB recommends that the DPUC determine whether – and, if so, in what circumstances – the suggested renegotiation of the foregoing contracts can take place.

D. Customer-Side Distributed Resources

The *Energy Independence Act* establishes a preference for customer-side distributed resources, which may include conservation and load management, including peak reduction and demand response, or generation (up to 65 MW) at a retail customer location. The Act also authorizes the DPUC to establish grants for these resources for the purpose of reducing FMCCs.

Customer-side distributed resources that have the highest potential to reduce FMCCs include:

1. Peak reducing conservation and load management measures as described above with respect to ECMB/utility sponsored programs;

2. Distributed generation resources that are controlled and callable for 10- and 30-minute response that qualify for ISO-NE operating reserves; and

3. Distributed generation used in response to calls for peak load reduction or used for peak shaving.

A preference should be given to those measures that can be implemented in the Stamford/Norwalk sub-area so as to have the maximum effect on the reduction on energy congestion and operating reserves. Measures implemented in other locations in the Southwest Connecticut zone also provide substantial benefits, thus also may deserve preferential treatment. For example, such projects could receive priority treatment in any utility or public permitting reviews that must be performed. Measures implemented in the rest of Connecticut also can mitigate LICAP costs (should that ISO proposal be implemented), perhaps to a somewhat lesser degree.

E. Public Education

To achieve the maximum benefits from rate design changes and load response programs to reduce peak demand during the summer of 2006, the DPUC should consider taking steps to provide consumers with objective information about the economic importance of reducing consumption during peak periods and the means by which to do so. Typically, the need for energy curtailment is presented to the public in the context of concerns about system reliability. It may help to reduce peak

C. Contracting Approaches to Mitigate Exposure to Spot Markets

The current circumstances may warrant consideration of standard offer supply procurement methods that depart from procedures reasonably followed in the prior capacity market, particularly as they pertain to the mitigation of FMCCs and price volatility risks in the ISO's proposed LICAP market. Standard offer designs which include forward contracting for capacity, reserves, and ancillary services will reduce the portion of Connecticut load exposed to spot markets for energy, capacity, and ancillary services. Contracting approaches may serve to mitigate the inherent price volatility of these markets and could offer cost-effective alternatives to purchases directly from these markets. It should be recalled that parties to a contract for capacity pay (or receive, as the case may be) the contract prices for the duration of their contract. That is, exposure to the capacity spot market (such as LICAP) is reduced by contracted capacity amounts.

8.3 Transmission and Import Capability

Inter- and intra-state transmission will remain constrained even after the implementation of the Phase I and II projects. A number of transmission projects are under development that will provide some measure of mitigation to FMCCs in SWCT or in the State more generally. Two projects scheduled for completion in 2007 are noted below. Also discussed below is a recommendation for additional transmission studies to be undertaken by the Connecticut utilities.

A. Bethel-Norwalk 345 kV Transmission Line

This line is under construction and scheduled for completion in December 2006. If completed on this schedule, is expected to increase import capability into SWCT by 275 MW. This upgrade will make a significant contribution to the mitigation of FMCC's in SWCT.

To mitigate FMCCs in 2007, this project must be completed on schedule; if delayed, added actions may be necessary to mitigate FMCC costs in that year. The progress of this project should be actively monitored to ensure that all actions needed from the State to implement it on schedule are taken. The DPUC should, in the CEAB's view, require regular and detailed project status reports, including disclosure at the earliest possible time of any potential or foreseeable delays; this will maximize the time available, in the event of a delay, to take actions to mitigate FMCCs in 2007.

B. Mystic-Wood River Reconductoring

This line is under construction and scheduled for completion prior to the summer of 2007. It is expected to increase import capability into Connecticut by

With respect to other generation, with one exception, the CEAB recommends that no new major projects be undertaken until need is more precisely established and decisions regarding the extent to which hedges in the capacity market should be sought have been made. That is, any long-term contract for capacity is a hedged instrument and should be part of an overall portfolio strategy. The exception noted above refers to quick start capacity, as will be discussed below.

A. Preferred Generation Resources

The *Energy Independence Act* and the *Act Concerning Long Term Planning for Energy Facilities* establish preferences for distributed generation, combined heat and power, and certain renewable energy resources. In addition, the CEAB has set forth its Preferential Criteria for Evaluation of Energy Proposals. The DPUC should seek to advance those resources specifically encouraged in the Public Acts which measure favorably against the preferential criteria. One example of such an initiative concerns the process by which the State is implementing a program that calls for the electric distribution companies to enter long-term contracts for 100 MW of renewable energy pursuant to Con. Gen. Stat. Sec. 16-244c(j)(2).

As with the conservation and load management measures described above, locational preference should be given to those measures that can be implemented in the Stamford/Norwalk sub-area; these measures will have the maximum effect on reducing energy congestion and operating reserves. Measures implemented in other locations in SWCT also provide substantial benefits. Measures implemented in other locations in Connecticut may provide some benefits in mitigating LICAP costs.

B. Other Generation

In addition to the preferred generation resources discussed above, other generation resources that could best mitigate Connecticut's FMCCs in the near term would be those that provide quick start capabilities in the form of 10- and 30-minute operating reserves. Facilities of this type should be located in the Stamford/Norwalk sub-area to have the maximum effect on the reduction of costs associated with energy congestion and operating reserves. Such facilities in other locations in SWCT may also provide substantial benefits. Fuel security (in the form of firm fuel supply contracts) or dual fuel capabilities should be a priority, as well.

In normal circumstances, the CEAB would recommend that any major generation capacity be acquired through the contemplated RFP process described in the Act. Projects that participate in the RFP process could include already-permitted generation facilities that have not yet been constructed, among others. A possible exception to this suggested RFP process may be incremental quick start capacity in the

C. Forward Reserve Market Design

ISO-NE, in conjunction with a stakeholder committee, is developing a locational market structure for operating reserves. This work is scheduled to be conducted for implementation in the latter half of 2006. Connecticut has substantial local operating reserve requirements due to transmission limitations.

Reference List

1. Connecticut's *Act Concerning Energy Independence Act,* Public Act 05-01.
2. Connecticut's *Act Concerning Long-Term Planning for Energy Facilities,* Public Act 03-140.
3. Federal Energy Regulatory Commission's *Initial Decision, Devon Power LLC, et al.*, Docket No. ER03-563-030, June 15, 2005 (the "LICAP Decision").
4. ISO New England's *Connecticut Energy Plan Framework: Recommended Solutions and Actions for the State of Connecticut*, January 4, 2005.
5. ISO New England's *2005 Capacity, Energy, Loads and Transmission Report*, April 2005.
6. ISO New England's *First Draft Regional System Plan 2005,* August 2005.
7. ISO New England's *2004 Annual Markets Report*, July 2005.
8. ISO New England Press Release, *New England's Electricity Use Sets New All-Time Record*, July 19, 2005.

Appendix 1

Connecticut's Needs for Additional Resources

This Appendix presents several views of Connecticut's needs for additional electric capacity resources, based on information that has been obtained to date. Connecticut's needs are driven by three sets of power system reliability calculations.

The first reliability calculation pertains to ISO-NE's proposed LICAP market, whereby capacity costs to entities serving domestic loads (and by direct extension, to customers under the State's regulatory framework for recovery of FMCCs) will be established. These LICAP charges will vary, depending on how the total quantity of qualifying in-zone generating capacity (i.e., as measured in megawatts, MWs) and Capacity Transfer Limits (CTL)[33] combined compared to a monthly Objective Capability (OC) target that is set by ISO-NE for each LICAP zone. The higher the ratio is, the lower the resulting LICAP prices. Thus, it is important that Connecticut planners have a clear view of the degree to which its likely capacity resource levels will affect LICAP costs.

Connecticut's needs also may be affected by an Operable Capacity (OpCap) assessment that ISO-NE routinely performs to test the ability of the bulk power system to respond to hypothetical contingencies, which typically include outages at the largest transmission or generating facilities. It is not yet clear what actions ISO-NE may take to ensure that OpCap remains at acceptable levels into the future. Consequently, the cost impacts of OpCap are uncertain.

ISO-NE also prescribes a third reliability requirement in order to ensure a sufficient level of operating reserves that includes quick-start units. In its recent Draft RSP05 Report, ISO-NE recommends that an additional 550 MW of quick-start units are needed in Greater Connecticut to meet its 1,200 MW operating reserve requirement. Of the 550 MW, 350 MW would be needed in SWCT once Phase II of the SWCT Reliability project enters service.

This Appendix assesses the performance of Connecticut taken as a whole and one of its two LICAP zones (i.e., Southwest Connecticut, or SWCT) relative to the OC and OpCap reliability standards. In the attached charts, we also provide a view of the ISO's stated requirement for additional quick start operating reserves. As a general matter, to the extent that the majority of the State's resources are located in the Rest of Connecticut (ROC) load zone, ROC has sufficient resources to meet the OC and OpCap reliability standards. Two cases based on different sets of load forecasts are presented to explore Connecticut's needs. Each case is briefly described below and presented in the tables that follow.

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[33] The CTL is the upper limit of capacity transfers allowed across an interface, but the actual amount of imported capacity may be less than the limit depending supply/demand balance of other zones.

are not reflected in the referenced forecast, thus Case 2a identifies several such offsets in calculating Peak Load, Net of Offsets values that flow into the OC and OpCap need calculations.

In Case 2a, calculations for the State are based on the sum of the state utilities' forecasts, while in Case 2b, calculations for Southwest Connecticut are based on an estimate of its portion of the statewide load (i.e., calculated as half of the sum of the utilities' peak load forecasts, as identified under Case 2a above). Various capacity and transmission resources are the same as in Case 1 for CT and SWCT.

The calculations in Case 2 result in substantial resource (i.e., capacity) surpluses under OC, OpCap, and operating reserve requirements across the planning horizon.

(Continued from previous page)

Line	Note	Capacity Situation (Summer MW)	2005	2006	2007	2008	2009
34	n.	**Peak Load, Net of Offsets**	**7,125**	**7,220**	**7,320**	**7,450**	**7,575**
35							
36		**Reserves for Op Cap:**					
37	o.	Largest Unit	1,200	1,200	1,200	1,200	1,200
38	p.	90/10 Load Increment	455	455	475	480	490
39	q.	Assumed Unavailable Capacity	483	483	483	483	483
40		**Total Required Reserves**	**2,138**	**2,138**	**2,158**	**2,163**	**2,173**
41							
42		**Op Cap Requirement for CT**	**9,263**	**9,358**	**9,478**	**9,613**	**9,748**
43							
44		Current In-State Capacity	6,779	6,779	6,779	6,779	6,779
45	r.	Deactivated Capacity (Devon 7 and 8)	n/a	n/a	n/a	n/a	n/a
46		New Capacity (e.g., Kleen)	?	?	?	?	?
47		New Renewable Capacity	0	0	0	0	20
48	s.	Current In-State Import Limit	2,300	2,300	2,300	2,300	2,300
49	t.	Phase I SWCT Transmission Upgrade			n/a	n/a	n/a
50	u.	Mystic CT to Wood River RI Trans. Upgrade			150	150	150
51		SWCT RFP	218	250	256	256	187
52		Total Other Load Response Programs	38	38	38	38	38
53		**Total Resources for Op Cap**	**9,335**	**9,367**	**9,523**	**9,523**	**9,474**
54							
55		**CT Op Cap Surplus (Deficiency)**	72	9	45		

Notes to Case 1a:

a. ISO-NE's unadjusted 50/50 forecast for CT is not known. Calculations derive From the adjusted forecast for CT, as shown in Line 13.

b. This ISO-NE peak load forecast for CT appears to tie directly to the CELT Adjusted Reference Case forecast (which is net of DSM offsets), as reflected in backup materials to the 2005 CELT Report.

c. The forecast reserve margin for the region, as reflected in ISO-NE's forecast of Objective Capability.

d. Total July 2005 Seasonal Claimed Capability for Connecticut generating units.

e. ISO-NE rules may permit the capacity from these deactivated facilities to qualify as installed capacity for purposes of determining LICAP charges, for a period of three years (assumed to end after 2006).

f. It is not known whether any new units, or which, will enter commercial service during the forecast period.

g. Connecticut's recent Energy Bill requires load serving entities to present to the DPUC contracts for at least 100 MWs of new renewable generating capacity, by July 2008.

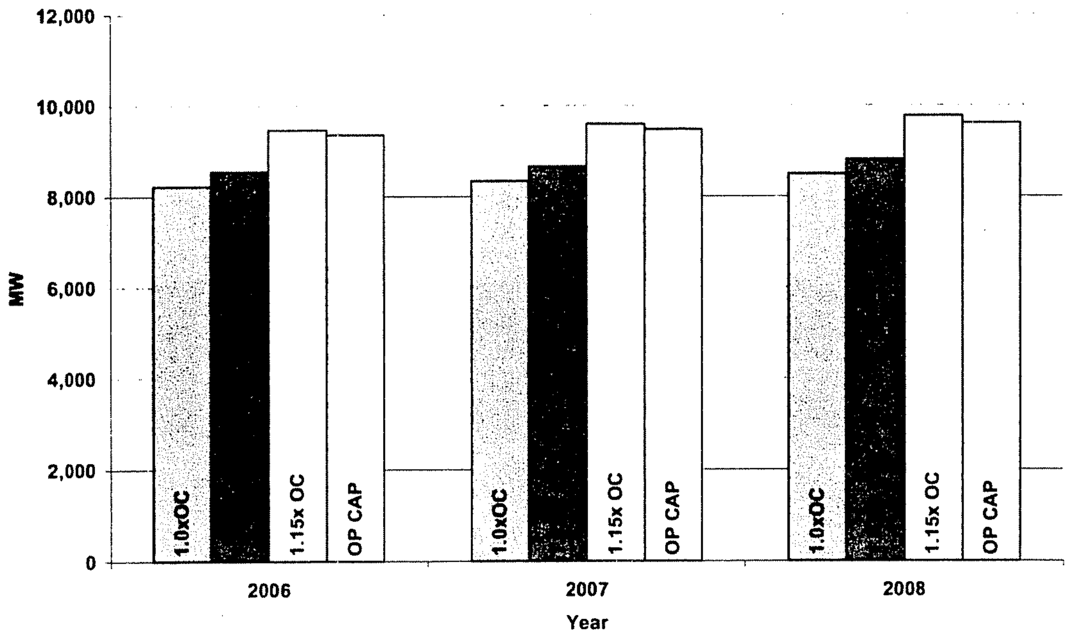
h. The forecast capacity from temporary generation under the "GAP RFP" is assumed to expire after 2008. Capacity from load response programs contracted under the GAP RFP is assumed to remain available to CT after 2008 and 2009.

i. ISO-NE identifies 25 MW of load response in ROC as under contract.

j. CL&P identifies a larger number of MWs as participating in ISO-NE load response programs. One cannot determine whether or to what degree CL&P's numbers duplicate those in Line 24. It is clear that the DPUC directed CL&P to invest an additional $1 million in ISO-NE load response programs, which CL&P estimates represents an additional 12.5 MWs, after the January 2005 date of the FERC filing from which Line 24 derives.

k. This Capacity Transfer Limit for CT is identified in ISO-NE's LICAP Model for CT. 100 MWs are added to reflect increased transmission capability into CT per the Draft RSP 2005, and 300 MWs to SWCT's CTL.

Case 1a: OC and OP CAP Comparisons for CT Using ISO-NE Forecast Method

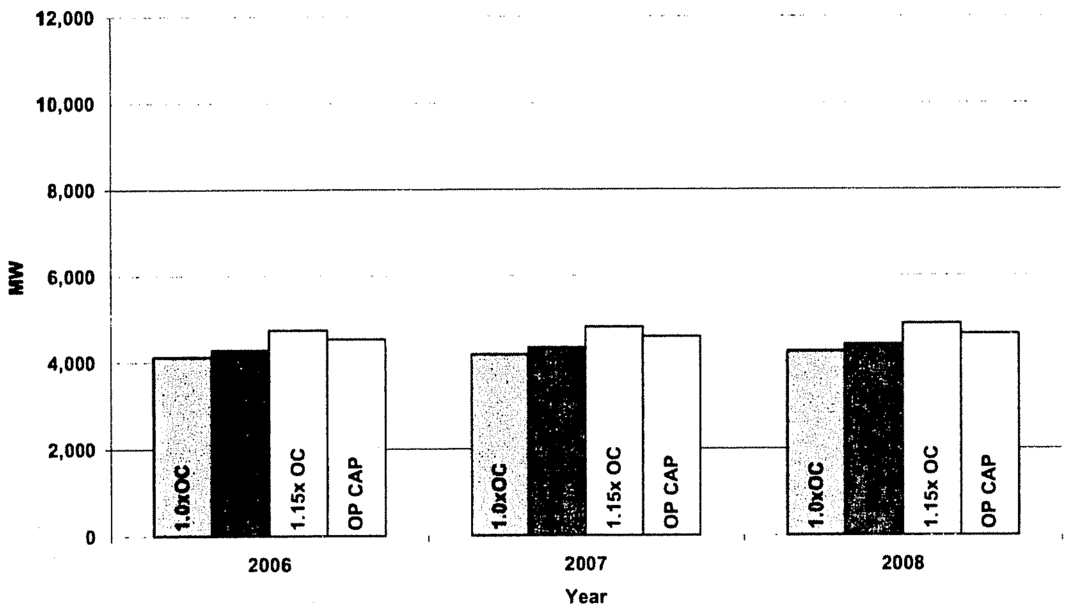


Projected Capacity Situation - Case 1b

SWCT: Using ISO Load Forecast

Notes	Capacity Situation (Summer MW)	2005	2006	2007	2008	2009
	ISO Load (50/50) Forecast for SWCT	?	?	?	?	?
	Offsets to Load:					
	Known Utility C&LM Programs	?	?	?	?	?
	Class III Renewables (Conservation, Cogen)	?	?	?	?	?
	Time-of-use Pricing (per Energy Bill)	?	?	?	?	?
	Distributed Generation Incentives	?	?	?	?	?
	Alternative TSO (C&LM offerings)	?	?	?	?	?
	Federal / State Energy Efficiency Standards	?	?	?	?	?
	Other	?	?	?	?	?
	Total Offsets	?	?	?	?	?
a.	**Peak Load, Net of Offsets**	**3,545**	**3,620**	**3,665**	**3,725**	**3,780**
	Required Reserve Margin for OC	14%	14%	14%	14%	14%
	Required Reserves for OC	**496**	**507**	**513**	**522**	**529**
	OC Requirement For SWCT	**4,041**	**4,127**	**4,178**	**4,247**	**4,309**
	Current In-State Capacity	2,376	2,376	2,376	2,376	2,376
	Deactivated Capacity (Devon 7 and 8)	212	212	0	0	0
	New Capacity (e.g., Kleen)	?	?	?	?	?
b.	New Renewable Capacity	0	0	0	0	10
	SWCT RFP	218	250	256	256	187
	ISO Load Response per ISO	0	0	0	0	0
c.	ISO Load Response per CL&P	6	6	6	6	6
d.	Capacity Transfer Limit	2,019	2,019	2,019	2,019	2,019
e.	Phase I SWCT Transmission Upgrades			275	275	275
f.	Mystic CT to Wood River RI Trans. Upgrades			n/a	n/a	n/a
	Total Available Resources	**4,831**	**4,863**	**4,932**	**4,932**	**4,873**
	SWCT OC Surplus (Deficiency)	790	736	754	686	564

Case 1b: OC and OP CAP Comparisons for SWCT Using ISO-NE Forecast Method



Projected Capacity Situation - Case 2a

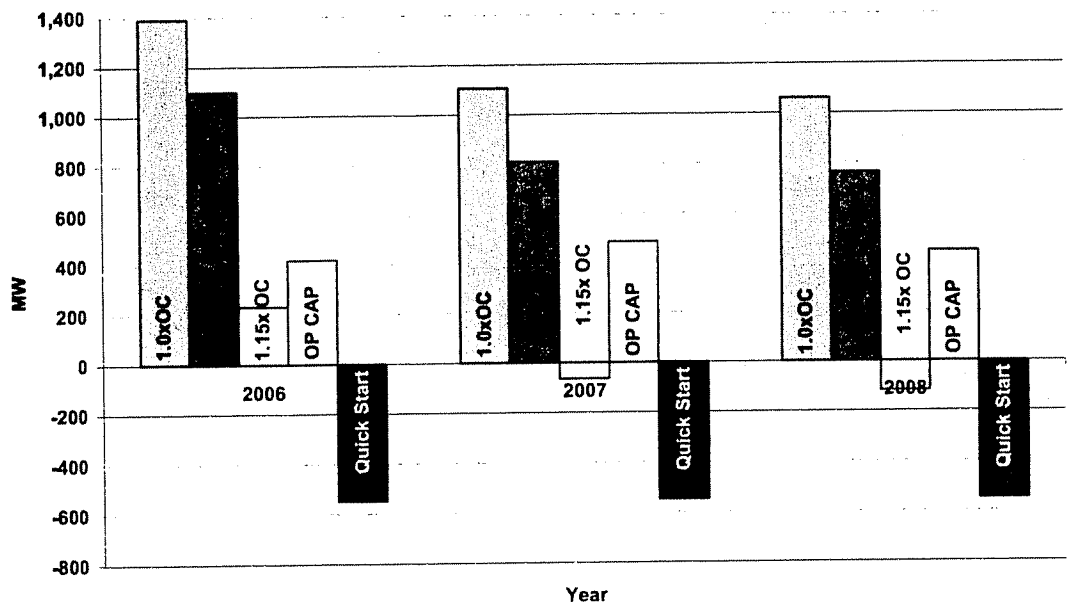
State of Connecticut: Using Utility Combined Forecasts

	Notes	Capacity Situation (Summer MW)	2005	2006	2007	2008	2009
1	a.	**Sum Utilities Forecast for CT**	**6,757**	**6,842**	**6,950**	**7,026**	**7,113**
2							
3		**Offsets to Load:**					
4	b.	Known Utility C&LM Programs	13	67	105	140	159
5	c.	Class III Renewables (Conservation, Cogen)	?	?	?	?	?
6	d.	Time-of-use Pricing (per Energy Bill)	?	?	?	?	?
7	e.	Distributed Generation Incentives	?	?	?	?	?
8	f.	Alternative TSO (C&LM offerings)	?	?	?	?	?
9	g.	Federal / State Energy Efficiency Standards	?	?	?	?	?
10	h.	Other	?	?	?	?	?
11		Total Offsets	13	67	105	140	159
12							
13		**Peak Load, Net of Offsets**	**6,744**	**6,775**	**6,845**	**6,886**	**6,954**
14							
15		Required Reserve Margin for OC	14%	14%	14%	14%	14%
16		Required Reserves for OC	**944**	**949**	**958**	**964**	**974**
17		**OC Requirement For CT**	**7,689**	**7,724**	**7,803**	**7,850**	**7,928**
18							
19		Current In-State Capacity	6,779	6,779	6,779	6,779	6,779
20		Deactivated Capacity (Devon 7 and 8)	212	212	0	0	0
21		New Capacity (e.g., Kleen)	?	?	?	?	?
22		New Renewable Capacity	0	0	0	0	20
23		SWCT RFP	218	250	256	256	187
24		ISO Load Response per ISO	25	25	25	25	25
25		ISO Load Response per CL&P	13	13	13	13	13
26		Capacity Transfer Limit	1,837	1,837	1,837	1,837	1,837
27		Phase I SWCT Transmission Upgrades			n/a	n/a	n/a
28		Mystic CT to Wood River RI Trans. Upgrades			150	150	150
29		**Total Available Resources**	**9,084**	**9,116**	**9,060**	**9,060**	**9,011**
30							
31		**CT OC Surplus (Deficiency)**	1,395	1,392	1,256	1,210	1,083

h. Other offsets are not yet identified.

i. Here, the increment to achieve a "90/10" forecast is calculated as the "90/10 Load Increment" from case 1a times the ratio of the Peak Load, Net of Offsets under the combined utilities forecast (Line 13, above) to the same figure under the ISO forecast (i.e., Line 13 in Case 1a).

Case 2a: OC, OP CAP and Quick Start Surplus (Deficit) for Greater CT Using Sum of Utilities' Forecast Method



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Notes	Capacity Situation (Summer MW)	2005	2006	2007	2008	2009
	Peak Load, Net of Offsets	**3,372**	**3,388**	**3,422**	**3,443**	**3,477**
	Reserves for Op Cap:					
	Largest Unit	451	451	451	451	451
	90/10 Load Increment	225	230	240	240	250
	Assumed Unavailable Capacity	232	232	232	232	232
	Total Required Reserves	**908**	**913**	**923**	**923**	**933**
	Op Cap Requirement for SWCT	**4,280**	**4,301**	**4,345**	**4,366**	**4,410**
	Current In-State Capacity	2,376	2,376	2,376	2,376	2,376
	Deactivated Capacity (Devon 7 and 8)	0	0	0	0	0
	New Capacity (e.g., Kleen)	?	?	?	?	?
	New Renewable Capacity	0	0	0	0	10
	Current SWCT Import Limit	2,300	2,300	2,300	2,300	2,300
	Phase I SWCT Transmission Upgrade	0	0	275	275	275
	Mystic CT to Wood River RI Trans. Upgrade			n/a	n/a	n/a
	SWCT RFP	218	250	256	256	187
	Total Other Load Response Programs	6	6	6	6	6
	Total Resources for Op Cap	**4,900**	**4,932**	**5,213**	**5,213**	**5,154**
	SWCT Op Cap Surplus (Deficiency)	620	632	868	847	744

Notes to Case 2b:

Unless noted herein, notes from Case 2a and Case 1b apply.

a. Estimated at half of the Case 2a forecast.

b. Estimated at half of the Case 2a forecast.

Appendix 2

Estimated LICAP Costs to Connecticut

This Appendix presents the results of a series of estimates of the costs that load serving entities in Connecticut, and thus the consumers that they serve, may incur under ISO-NE's proposed LICAP market (which, if implemented, will be in place no earlier than October 1, 2006). The CEAB modified and ran a model for estimating LICAP costs that initially was developed by ISO-NE in August 2004, and later was converted to a multi-year model with assumptions as detailed in Table 1. ISO-NE describes its LICAP model as follows:[34]

> The clearing portion of the model includes the five proposed LICAP zones and models the capacity transfer constraints (CTRs) between the zones, the quantity of capacity actually in each zone, the LICAP obligation assigned to each zone, and the demand curve adjusted to fit the parameters for each zone. Using linear optimization techniques implemented in the "solver" module of the Microsoft Excel spreadsheet software, the model varies the amount of capacity transferred over each zonal interface, subject to the transfer limits, with the objective of maximizing social benefit. Social benefit is maximized when the marginal benefit from increasing transfers to the constrained side of an interface is equal to the marginal cost of the change. This benefit optimization considers costs and benefits to suppliers as well as to load in arriving at an optimal solution.
>
> The remainder of this model deals with the process of settling the market to develop cost projections. Issues addressed include the quantity of capacity purchased in each zone and the price paid for that capacity, the quantity of capacity actually transferred over each interface, and the settlement of capacity transfer rights....
>
> Inputs to the model include the demand curve parameters for each LICAP zone and the planning assumptions for the year analyzed. The planning assumptions include the quantity of capacity assumed to be available in each zone, the transfer limits between zones, and the total obligation of each zone....

CL&P used the same multi-year model and assumptions as ISO-NE, except it updated the Objective Capability (OC) for the New England control area in its assessment of LICAP costs.[35] The CEAB subsequently updated or modified a number of the assumptions model, including OC, generating unit re-rates, retirements and reactivations, and transmission upgrades. The CEAB and ISO-NE/CL&P input assumptions are presented in Table 2.

LICAP clearing prices and net cost to load by zone were estimated starting with the 2006/2007 planning year and continuing through planning year 2008/2009.

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[34] Excerpt from Exhibit No. ISO-39, Revised Page 51 of 74, Prepared Rebuttal Testimony of Mark Karl on Behalf of ISO-NE, in FERC Docket No. ER03-563-030.

[35] Zonal OCs are allocated based on a zone's share of the previous calendar year's actual, ISO-NE control area, system-wide peak.

Table 2:
Comparison of CL&P to CEAB Modeling Assumptions

	ISO-NE/CL&P Assumptions	CEAB Assumptions
New England Control Area OC	CL&P adjusted the 2005/2006 Control Area OC from ISO-NE's December 2004 LICAP Cost Analysis with an updated 2005/2006 OC dated May 10, 2005 as approved by FERC , then escalated that new value growing at 1.3% per year.	The zonal OCs for New England's non-Connecticut zones were calculated as a fixed percentage of the Control Area's July OC value for each forecast year, as taken from "TABLE 1: Draft - 05/06 OC Values Assuming 2,000 MW Tie Benefits." The two sets of SWCT and ROC zonal OCs reflect two different load scenarios, as described in Appendix 1[37].
Capacity Transfer Limit (CTL)	CL&P maintained same capacity CTLs used by ISO-NE in its model.	The CEAB used the same CTLs as ISO-NE/CL&P with adjustments described in New Capacity/Transmission below.
Zonal OC Allocations	The shares used by ISO-NE in its December 2004 Analysis were applied to the new control area OC to allocate zonal OC for each year going forward.	Zonal OCs for non-Connecticut zones were calculated using same percentages of regional peaks as CL&P, applied to the July OC as described above. However, zonal OCs for SWCT and ROC were calculated using an alternative method, as described in Appendix 1.
Available Local Capacity	CL&P used the ISO-NE assumptions from its December 2004 LICAP Cost Analysis.	The CEAB updated claimed capacity levels within each zone to reflect ISO-NE's July 2005 Seasonal Claimed Capability report. The total available MW capacity for the ISO-NE control area was similar to CL&P values[38], except that NEMA capacity was adjusted to reflect reactivation of the Kendall[39] units (166 MW) and capacity retirements and derates (-190 MW).
Capacity Transfer Rights (CTR) Allocation Method	CTRs were calculated in the model using Gross Clearing Price, which is the clearing price from the LICAP demand curve before any adjustments are made for Peak Energy Rents (PER) and Equivalent	The CEAB calculated CTRs using "Adjusted Clearing Prices," i.e., after PER and EFORd were taken into account.

37 OC for Rest of Connecticut is not presented in Appendix 1, but is calculated based on the State's calculated OC minus SWCT's calculated OC from each of the two Load Cases in Appendix 1.

38 Capacity contributions from the GAP RFP and 1200 MW of HQ transmission capability into New England included in the calculation were similar to ISO-NE's assumptions.

39 The Kendall CT and Steam Unit 3 were reactivated for reliability purposes. Mirant and ISO-NE are currently negotiating an RMR agreement that would expire when LICAP takes effect (see FERC Docket No. ER05-26). However, it is assumed that the reactivated units would be counted toward LICAP in the 2006/2007 planning year.

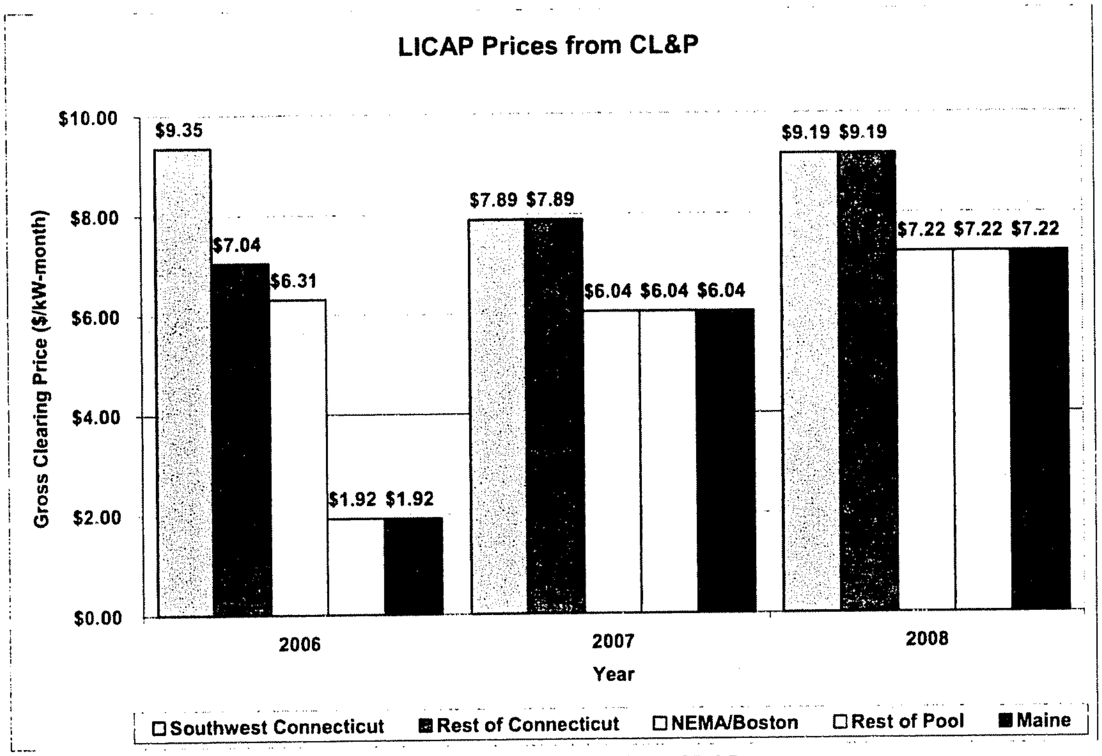

Figure 1: LICAP Prices from CL&P

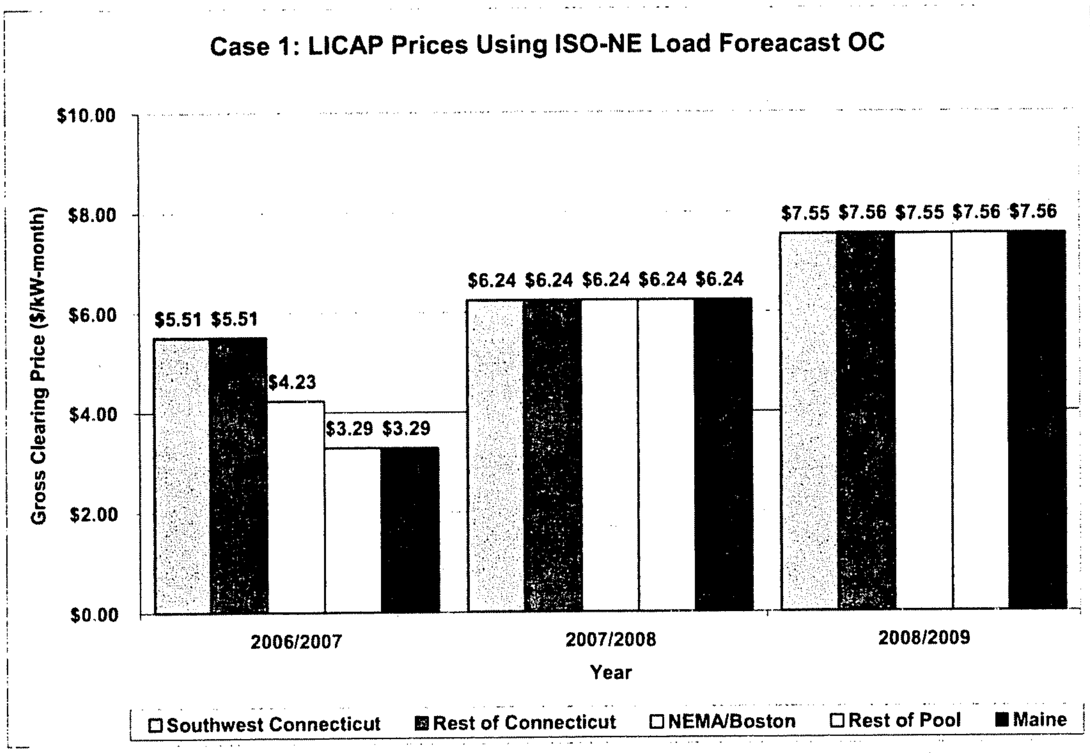

Figure 3: Case 1-LICAP Prices Using ISO-NE Load Forecast OC

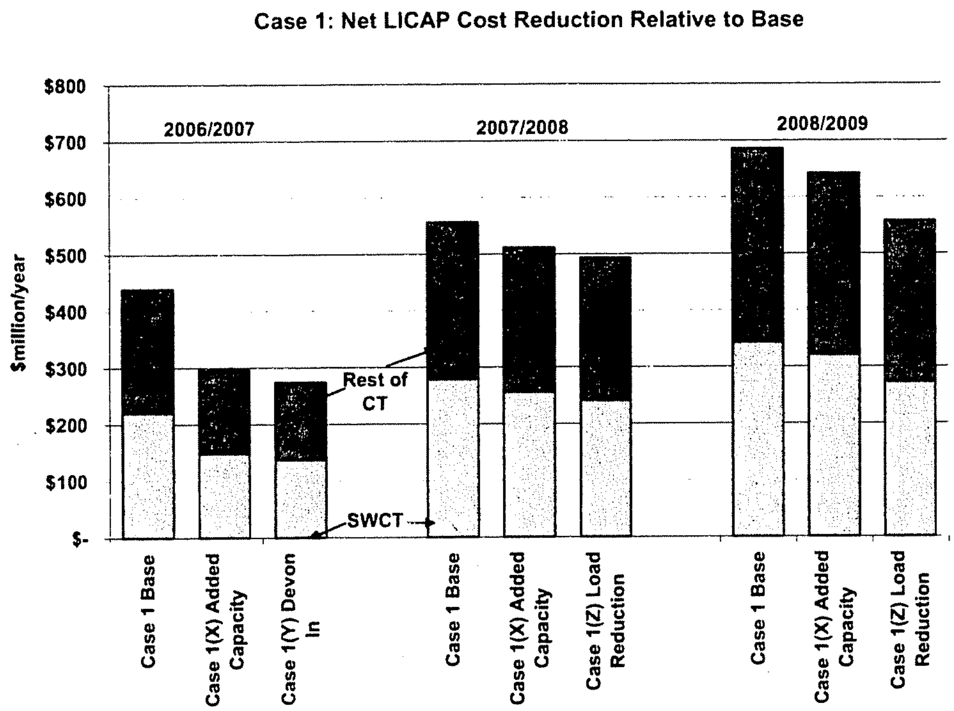

Figure 5: Case 1 OC Strategies

Appendix 3

Glossary of Acronyms

AGC	Automated Generation Control
ASMs	Ancillary Services Markets
CEAB	Connecticut Energy Advisory Board
CEF	Connecticut Clean Energy Fund
CLM	Conservation and Load Management
CL&P	Connecticut Light and Power
CMEEC	Connecticut Municipal Electrical Energy Cooperative
CSC	Connecticut Siting Council
CTR	Capacity Transfer Constraints
DPUC	Department of Public Utility Control
DSM	Demand Side Management
EBCC	Estimated Benchmark Cost of Capacity
ECMB	Connecticut Energy Conservation Management Board
EFORd	Equivalent Demand Forced Outage Rate
FERC	Federal Energy Regulatory Commission
FMCCs	Federally Mandated Congestion Charges
ISE	Institute for Sustainable Energy
ISO-NE	Independent System Operator of New England
KWh	Kilowatt-Hours
LICAP	Locational Installed Capacity
LMP	Locational Marginal Pricing
LSE	Load Serving Entities
MW	Megawatt
MWh	Megawatt-hours
OC	Objective Capability
OpCap	Operable Capability
ORC	Operating Reserve Credits
PUSH	Peaking Unit Safe Harbor
RFP	Request for Proposals
RMR	Reliability Must Run
ROC	Rest of Connecticut Zone
RSP	Regional System Plan
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organizations
SMD	Standard Market Design
SWCT	Southwest Connecticut Zone
TOU	Time of Use
TSO	Transitional Standard Offer
UI	United Illuminating