**STATE OF CONNECTICUT**

**BEFORE THE CONNECTICUT SITING COUNCIL**

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| CL&P Application for the Greater | ) | |
| Springfield Reliability Project and the | ) | Docket No. 370A |
| Manchester to Meekville Circuit | ) | |
| Separation Project | ) | |

# DIRECT TESTIMONY OF

# PAUL CHERNICK

**ON BEHALF OF**

# THE CONSUMER COUNSEL

Resource Insight, Inc.

**JULY 7, 2009**

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## I. Identification and Qualifications

**Q: Mr. Chernick, please state your name, occupation, and business address.**

A: I am Paul L. Chernick. I am the president of Resource Insight Inc., 5 Water St, Arlington, Massachusetts.

**Q: Summarize your professional education and experience.**

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

**Q: Have you testified previously in utility proceedings?**

A: Yes. I have testified in more than two hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in 24 states and four Canadian provinces, and two Federal agencies.

**Q: Have you testified previously before the Connecticut Siting Council?**

A: Yes. I testified on behalf of the Office of Consumer Counsel (OCC) in CSC Docket No. 217, on transmission upgrades to southwestern Connecticut.

**Q: Have you testified previously before the Connecticut Department of Public Utility Control?**

A: Yes. I testified in the following cases:

- Docket No. 83-03-01, a United Illuminating (UI) rate case, on Seabrook costs.
- Docket No. 83-07-15, a Connecticut Light and Power (CL&P) rate case, on behalf of Alloy Foundry, on industrial rate design.
- Docket No. 99-02-05, the CL&P stranded-cost docket.
- Docket No. 99-03-04, the UI stranded-cost docket.
- Docket No. 99-03-35, the UI standard-offer docket.
- Docket No. 99-03-36 (initial phase), the CL&P-standard-offer docket.
- Docket No. 99-08-01, investigation into electric capacity and distribution.
- Docket No. 99-09-12, the nuclear-divestiture plan for CL&P and UI.
- Docket No. 99-09-03, on the performance-based ratemaking proposal of Connecticut Natural Gas.
- Docket No. 99-09-12 RE01, on the Millstone auction.

- Docket No. 99-03-36 RE03, on CL&P's Generation Services Charge.
- Dockets Nos. 99-04-18 Phase 3 and 99-09-03 Phase 2, on the proposed earnings-sharing mechanism of Southern Connecticut Natural Gas and Connecticut Natural Gas.
- Docket No. 03-07-02, on behalf of AARP, on the distribution investment plan and rates for CL&P.
- Docket No. 03-07-01, on behalf of AARP, on the application of the rate cap to CL&P's transitional standard offer.
- Dockets No. 03-07-01RE1 and 03-07-15RE2, on CL&P and UI requests for incentives for mitigating transitional standard offer costs.
- Docket 05-07-18, on whether capacity contracts impose costs on the electric utilities.
- Docket 06-01-08, on multiple rounds of procurement results, on lessons learned from the procurements, and on procurement options.
- Docket 05-07-14PH2, on the cost-effectiveness of capacity contracts proposed under the Energy Independence Act.
- Docket 07-08-24, on the process for the procurement of peaker capacity.
- Docket 08-01-01, on the evaluation and selection of contracts for new peakers.
- Docket 08-01-07, the 2008 Connecticut Integrated Resource Plan (IRP).

Except as noted, this testimony was on behalf of the OCC.

## II. Introduction

**Q: On whose behalf are you testifying?**

A: My testimony is sponsored by the Office of Consumer Counsel.

**Q: What is the purpose of your direct testimony?**

A: The Office of Consumer Counsel has asked me to review the case CL&P has presented for a reliability need for the Greater Springfield Reliability Project (GSRP), which CL&P sometime combines with the Manchester to Meekville Junction Circuit Separation Project (MMP) as the Connecticut Valley Electric Transmission Reliability Projects. I have not reviewed whether there might be any need for the MMP in the absence of the GSRP. The GSRP is a part of the set of transmission projects called the New England East-West Solution.

**Q: Please summarize your conclusions.**

A: CL&P has not shown any need for its GSRP project, either at present or within any future time period used by system planners (including ISO New England and CL&P). The Company's "need' analyses rely on numerous assumptions that are implausible or even impossible.

The transmission analyses that CL&P presents are designed to force transfers of power over the transmission lines from Rhode Island and western Massachusetts into Connecticut to maximum tolerable levels or beyond. To force those transfer limits in its modeling, CL&P takes the following two remarkable actions:

- Positing a long series of extraordinary and even impossible conditions: the most demanding weather conditions, highly unlikely geographic patterns of generation, unprecedented and even excessive transmission loadings, the complete suspension of all future energy-efficiency efforts, and the operation of retired power plants.
- Assuming that the ISO would willfully violate its own reliability procedures and create a situation in which the transmission system is very vulnerable to any problem.

These initial conditions are central to CL&P's modeling, but they do not form a reasonable basis for determining the need for transmission upgrades.

The company tests the artificially overloaded system by modeling a series of contingencies, eliminating transmission lines and other equipment. This testing process would be appropriate, *if* the initial conditions in the scenarios were plausible and *if* the assessment realistically reflected the response of the system to the contingencies. Since CL&P starts its analysis assuming that the transmission system connecting western Massachusetts to Connecticut would be loaded at or above its limits, many of these contingencies push other lines over their long-term ratings, which (were nothing done in response) could damage equipment and lead to cascading outages of transmission and generation. New England's electric system is centrally managed and dispatched by the independent system operator (ISO). Were the contingencies modeled by CL&P actually to occur, the ISO would reduce line loading before the transmission lines could fail, by increasing generation in the Springfield area and in Connecticut, by reducing or eliminating exports from Connecticut to Long Island, by calling on assistance from New York, and by reducing generation and imports in other parts of New England. But CL&P does not reflect the way that the New England power system actually responds to transmission outages, such as by changing generation and interchange. The analyses supporting CL&P's application ignore these actual, real-world responses, and are thus totally unrealistic and irrelevant to prudent and cost-effective planning.

The analyses presented in this case do not and (given those flaws) cannot demonstrate any reliability need for the GSRP in 2014 or at any other time within the planning horizons of Connecticut or the ISO.

The lack of appropriate analyses by CL&P leaves unanswered the question of whether some problems may occur on the local 115 kV transmission system, even with plausible dispatch and realistic response to outages. CL&P's Massachusetts affiliates should be working to determine whether such conditions exist or may exist, and if so, to determine whether potential overloads can best be avoided by keeping existing generation available, adding new capacity in the Springfield area, accelerating load reductions, enhancing demand-response programs, or improving the local transmission system.

**Q: Is it possible that the GSRP would be desirable in the future?**

A: Yes. It is possible that the program could have economic benefits, by increasing import capacity for Connecticut and allowing the deactivation of plants that might, in the future, request support payments to remain on line. However, CL&P has not addressed these economic issues in this proceeding, so there is no evidence that would allow for a comparison of the benefits and costs of the GSRP and the MMP. Simply comparing those benefits and costs would not be sufficient in any case, since very similar benefits could be achieved by generation within Connecticut. The costs of a transmission solution must be compared to the costs of generation and other alternatives, in addition to the costs of the do-nothing option.

Given the absence of any reliability need and of any estimate of the cost of congestion in the Springfield area, there does not appear to be any urgency in addressing these issues. The lights are not about to go out and there is no reason to believe that the costs of reliably operating the Springfield-area system will suddenly and dramatically increase.

**Q: What would be an appropriate procedure for assessing the costs and benefits of the GSRP?**

A: If CL&P continues to believe that the GSRP has benefits for energy consumers, it should submit its analyses for serious review in the Integrated Resource Plan

(IRP) process for 2010 or a subsequent year. In that process, mandated by §51 of Public Act 07-242, CL&P and UI prepare an analysis of various aspects of electricity load and supply, identify needs, and compare options for meeting those needs, including generation, transmission, energy efficiency, and demand-response options. The IRP is reviewed first by the Connecticut Energy Advisory Board (CEAB), which prepares its "Comprehensive Plan for the Procurement of Energy Resources" based on that review. The IRP and Procurement Plan are then reviewed by the DPUC, which can accept or alter the utility plans and can authorize construction and contracting to implement resources, including contracts for purchases from new or existing generating plants.

**Q: What would be the possible consequences of adding transmission capacity piecemeal, outside of the context of Connecticut's IRP process?**

A: The integrated-resource-planning process includes mechanisms for comprehensively selecting the most advantageous of the available alternatives. Examining options one at a time, on the other hand, limits decision making to the question of whether a particular option is better than doing nothing. Such piecemeal decisions are unlikely to choose the best investment and would thus impose unnecessary costs on Connecticut.

**Q: How does your review reflect on whether the Meriden plant should be constructed, under Docket 370B?**

A: Since I see no demonstration of a reliability need for any additional resources at this time, I have no basis for recommending the construction of the Meriden plant. I am aware that the CEAB Evaluation Report (February 17 2009) indicates that Meriden would be less expensive for Connecticut than the GSRP. I have not reviewed that analysis in detail, but based on a quick review, the CEAB analysis appears appropriately structured. Future IRP reviews can consider whether any additional resources are needed for reliability or (more likely) for economic purposes, and if so, whether those purposes can best be met by support of existing generation, by competitive procurement of new generation, and/or by construction of transmission.

**Q: Please describe the transmission reliability analyses in the Application.**

A: The company started with an assumed pattern of loads and generation around New England. Specifically, all the analyses are conducted for the summer peak hour in 2014, under unusually hot weather that would only be expected once every ten years.

The company then assumed four patterns of generation to meet that load. CL&P selected the specific generators that would be operating throughout New England. Application Table F-3 summarizes the Springfield-area units that are on line in CL&P's three "normal" generation cases (which CL&P calls "dispatch scenarios" D1, D2, and D3), and in a "contingency" variant of scenario D1 in which a transmission line into Connecticut is unavailable.[1] CL&P performed additional dispatch cases in response to CEAB, reflecting the generation proposals for Meriden and Towantic and a separate request from CEAB with additional peaking generation in Connecticut (provided in IR OCC-55).

Both the Application analyses and the additional cases performed for CEAB are dated, for a number of reasons. They are based on the 2008 ISO load forecast, they ignore the effects of energy-efficiency programs and demand response on the forecast, they include generating units that were retired years ago, and they exclude generators expected to be on line by 2014.

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[1] The company does not assign this scenario a distinct name shorter than "D1 with CT Import 1700 MW." I will call this scenario "D1-1700."

The company provided an Addendum to the Application analyses (as a supplementary response to IR OCC-9) on June 25, five or six business days prior to the due date for this testimony.[2] That analysis corrects some of the problems in the earlier analyses, and is better documented, so I will primarily review the Addendum analyses. The Addendum dispatch of Springfield-area units is the same as in the Application.

The public version of the Application does not specify which units are on line in other parts of New England, but those units are listed in the detailed dispatch runs provided in the confidential materials of the Application and Addendum. The most important part of the generation dispatch, other than the choice of specific Springfield-area units assumed to be on line, is the amount and choice of capacity that CL&P assumes is operating in Connecticut.[3] CL&P selected the Connecticut generation in its dispatch scenarios so that Connecticut is engaged in the following power transfers:

- importing 2,530 MW for scenarios D1, D2, and D3;[4]
- importing about 1,730 MW for scenario D1-1700;[5]
- exporting 350 MW to Long Island over the Cross-Sound Cable in each scenario.

Any particular geographical pattern of load, generation, imports, and exports will result in a specific pattern of electricity flows on each transmission

[2] July 3 is a Connecticut holiday, and July 6 is a state furlough day.

[3] The problems CL&P identifies in the absence of the Connecticut Valley Electrical Transmission Reliability Projects appear to be largely the result of power flowing from western Massachusetts to Connecticut.

[4] CL&P describes these cases as having 2,500 MW of imports.

[5] CL&P describes these cases as having 1,700 MW of imports.

line in New England. The operators of the transmission system—mostly the large investor-owned utilities under the supervision of the ISO—have only a limited ability to control how power flows through the network.

For each of the four dispatch cases (D1, D2, D3, and D1-1700), CL&P then simulates the outage of a number of power lines or other equipment, one at a time. For each outage (or "contingency"), the power flow would reroute itself, following the laws of physics. CL&P computes the new power flow and determines whether any of the lines will be carrying more than its summer long-term emergency (LTE) rating. A line generally can tolerate loads much higher than the LTE for short periods; the LTE is the level that the line can carry for 12 hours.[6]

For the analyses in this case, CL&P assumes that the pattern of generation *does not change* following the transmission outages (IR OCC-049-SP01). This is a critical error in the analyses, to which I will return in Section IV.

**Q: Have you identified any problems with CL&P's analysis?**

A: Yes. The first set of problems concerns CL&P's design of the dispatch cases. The second set of problems concerns the fact that CL&P ignores the actual response of generation to transmission outages. I discuss these two sets of problems in the following two sections.

## III. Choice of Starting Situations

**Q: What are the important assumptions in CL&P's analysis, in terms of system conditions prior to any transmission problems?**

[6] ISO New England Planning Procedure No. 7, Procedures for Determining and Implementing Transmission Facility Ratings in New England, February 14 2007.

A: The most important variables are the power flows into the Springfield area and through the Springfield area into Connecticut. Those power flows create the overloads following the modeled outages of various transmission lines. The power flows are increased by higher loads in the Springfield area and in Connecticut, by exports over the Cross-Sound Cable to Long Island, and by outages of generators in the Springfield area and in Connecticut. In its analyses, *CL&P forces enough Connecticut generation off line to push the flow into Connecticut to its pre-contingency limit,* so that loss of any related transmission component will be sure to create an overload.

### *A. Load Levels*

**Q: Are the loads in the CL&P studies representative of current expectations for load in 2014 on an extremely hot summer day?**

A: No. The loads in the dispatch runs are similar to the ISO's 2009 load forecast with some limited adjustments, but they lack other important and relevant adjustments.

The Connecticut load in the Addendum dispatch cases appears to vary from 7,754 MW to 7,777 MW.[7] These differences may result from differences in line losses with differing dispatch assumptions.

The current ISO forecast for the 90th percentile 2014 summer peak in the Connecticut sub-areas totals 8,370 MW, which Appendix A of the Addendum models as 8,157 MW at the substations, plus losses on transmission within Connecticut (about 2.6% losses).[8]

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[7] I derived these values by adding up the Connecticut generation output (e.g., 5,570 MW in D1), plus imports (2,531 MW in D1) and minus 352 MW of exports over the Cross-Sound Cable.

[8] The total load for Connecticut is projected at 8,455 MW; the other 85 MW of load in Connecticut is served through the Western Massachusetts transmission system and included in CL&P's

Unlike the Application, the Addendum recognizes that the ISO forecast must be adjusted to reflect load reductions from passive resources (energy-efficiency programs and electric generation reducing customer loads), which operate without ISO intervention, and active demand-response programs (which the ISO must dispatch as needed).[9] By design, the ISO forecast does not include these load reductions (Application F-30–F-31). The Addendum includes only load reductions from the resources that cleared in the ISO's Forward Capacity Auctions, which obligate suppliers to provide load reductions in specific future periods. From 2011 on, the Addendum analysis assumes that Connecticut load is reduced by 493 MW statewide, based on the resources that cleared (i.e., were selected) in the auction. These comprise 311 MW of energy efficiency and 182 MW of demand response.[10] The demand-response value used in the Addendum is 69% of the demand-response capacity that cleared in the auction. In short, the CL&P (and ISO) analyses heavily discount demand-response capacity.[11]

Given these load reductions, the Connecticut load from Appendix A should thus be 8,157 MW–493 MW = 7,663 MW, plus 2.6% losses for a transmission load of 7,864 MW. This value is about 60–80 MW more than the apparent load in the dispatch runs.

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load data as part of the Western Massachusetts load. I have tried to state all Connecticut load estimates net of the load served from Western Massachusetts.

[9]Energy efficiency accounts for most of the passive savings; I will sometimes use "energy efficiency" to mean all such passive-demand resources.

[10]These values do not include transmission losses.

[11]Neither the ISO nor CL&P has provided the basis for this large derating of demand-response capacity. In response to a request for the "basis for the percent of each type of resource assumed unavailable for Transmission Security Analyses, including supporting data for…(c) demand response" (OCC-63), the ISO offered only a link to a piece of testimony before FERC, which provides no supporting data and does not provide the 31% derating CL&P assumes.

**Q: What other adjustments are appropriate to the ISO load forecast?**

A: Two additional adjustments are required, one for energy-efficiency and the other for small generators.

**Q: What additional adjustment is required for energy-efficiency programs?**

A: The Addendum loads include only the portion energy-efficiency planned for installation by the summer 2011 that participated in the second Forward Capacity Auction, and excludes all effects of continuing energy-efficiency programs by CL&P, UI or CMEEC afterwards.

In contrast, the CL&P-UI 2009 IRP reports that, in addition to the energy-efficiency savings they have chosen to include in the second Forward Capacity Auction, CL&P and UI plan 38 MW of load reduction at the customer meter by 2012, or about 41 MW at the transmission level. By 2014, CL&P and UI plan to save another 199 MW (including losses), bringing their total planned energy efficiency not included in the second Forward Capacity Auction to 239 MW. This value should have been subtracted from the loads used in the Addendum, along with the effects of the CMEEC programs.[12]

**Q: What adjustment is appropriate for small generators?**

A: The company's dispatch analyses do not include the output of the following resources:

- about 30 existing units, comprising 66 MW of hydro generation and 77 MW of generation fueled by various waste materials (municipal solid waste, landfill and other biogas, and tires);

[12]All those energy-efficiency savings are estimated for normal peak conditions. At extreme peak, with all the efficient cooling equipment operating at high capacity, the savings are likely to be still higher.

- about 135 MW of fuel cells and other capacity under contract to the Connecticut utilities.[13]

The company says that these smaller units are deducted from loads (IR OCC-48).

Thus, the 2014 extreme-peak load on the Connecticut transmission system in the CL&P analyses should have been reduced by about 278 MW of generation,[14] as well as 239 MW of energy-efficiency, and would be about

$$7{,}864–239–278 = 7{,}347 \text{ MW.}$$

That load is roughly 420 MW less than the 7,754–7,777 MW used in the Application.

**Q: What would be the effect of a lower load on the transmission overloads following a contingency?**

A: In the real world, a lower Connecticut load should have one of two effects. Either Connecticut imports would be less, reducing loads on transmission lines both before and after a contingency, or some additional Connecticut generation would be available to respond to the contingency by increasing generation and relieving overloads.

Unfortunately, CL&P's approach would not recognize either of these effects, since CL&P insists on fully loading the Connecticut import regardless of Connecticut's need and does not allow generation to increase output in response to a transmission outage.

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[13]This consists of Project-150 capacity, minus 15 MW at the Watertown biomass project, which is included in the Addendum although CL&P always shows it as being shut off for its scenarios.

[14]Five or six additional MW of transmission losses would be avoided by operation of this generation at the distribution level. Some of the hydro generation might be held back by the ISO for reserves. As I discuss below, that hydro would be available to respond to a transmission outage, along with the Connecticut peakers.

**Q: When would Connecticut load at transmission level be expected to reach the range CL&P used in its analysis?**

A: Sometime after 2020. The ISO load forecast only runs only through 2018 and the IRP projection of energy-efficiency savings runs through 2019. Through that forecast period, the projected reduction of load due to energy efficiency essentially equals the projected growth in load. Reducing the loads from Addendum Appendix A by the IRP's forecast of energy efficiency not included in the second Forward Capacity Auction and by the 278 MW of small generators, the peak load on the Connecticut transmission system would stay essentially unchanged (within 10 MW of the 7,345 MW projection for 2014) through the end of the current forecasts in 2018 or 2019.

**Q: Can you perform similar comparisons for the Springfield area?**

A: No. ISO does not generally publish data on demand and demand resources for this area. In the Addendum, CL&P reports that the 2009 ISO forecast projects a 2014 peak load of about 1,085 MW for the Greater Springfield area, including the portion of Connecticut served from Massachusetts, or about

- 77% of the 1,400 MW reported for the "Western Massachusetts Area" reported in Addendum Appendix A,
- 45% of the 2,390 MW reported for the WMA subarea in the ISO's 2009 forecast Data File, the smallest area for which the ISO forecasts load,
- 26% of the 4,415 MW in the West-Central Massachusetts (WCMA) load zone, the smallest area for which the ISO reports data on energy efficiency and demand response.[15]

[15] In the comparisons to the ISO forecast, I added transmission losses to the loads reported in Appendix A.

Even the ISO's May 2009 needs update for the GSRP compares load forecasts and resources only at the Western Massachusetts level, not for any definition of Greater Springfield.[16]

The company reduces the 2014 Greater Springfield load by about 80.4 MW of energy-efficiency and demand-response savings, allocating 104 MW of load reductions among the Pittsfield, Berkshire, Greater Springfield, and northern-Massachusetts areas.[17] Again, the available data are insufficient for me to check these values. However, CL&P again assumes that energy-efficiency programs are limited to the savings that clearing in the second Forward Capacity Auction, even though Massachusetts is committed to greatly expanding its already vigorous energy-efficiency programs. The Massachusetts Green Communities Act requires that EDCs and municipal aggregators plan to acquire "all available energy-efficiency and demand-reduction resources that are cost effective or less expensive than supply," and established an Energy Efficiency Advisory Council (EEAC) to, among other things, determine the savings levels that would meet that standard. EEAC analyses have determined that the available cost-effective electric-energy savings would be 3% annually (2.5% from energy efficiency and 0.5% from CHP).[18] For the initial 2010–2012 ramp-

[16]Mezzanotte, Frank. "New England East-West Solutions (NEEWS) Rhode Island & Springfield Current 'Needs' Assessments," draft power-point presentation to be made to ISO-NE Planning Advisory Committee meeting June 17 2009. Holyoke, Mass.: ISO New England. Slide 18.

[17]I understand the Addendum, CL&P intended to allocate 53 MW of cleared energy-efficiency savings and 75% of 68 MW of cleared demand response, plus 5.5% distribution losses.

[18]"Available Cost−Effective Electric Savings: Energy Efficiency and CHP," EEAC Consultants, June 4 2009; Boston: Massachusetts Energy-Efficiency Advisory Council.

up period, the 2009 Three-Year DSM Plan filed by the utilities sets savings goals as shown in Table 1.[19]

**Table 1: Massachusetts Energy-Efficiency Plans**

| | Annual Load Reduction | |
|---|---|---|
| | *Summer MW* | *Annual GWh* |
| *2010* | 0.7% | 1.1% |
| *2011* | 0.8% | 1.3% |
| *2012* | 1.0% | 1.6% |

Appendix A of the Addendum includes a reduction of about 0.6% due to energy-efficiency in 2011, so the EEAC plan may result in a small additional decrease in load by 2011. [20] More important, the savings should continue to increase in 2012, 2103, 2104, and beyond. Since Appendix A projects annual load increases of 1% to 1.75%, even continuation of the 2012 planned summer load reductions would offset most load growth. If summer load reductions rise in proportion to the expansion of energy savings, peak loads would fall over time.

The company's analyses do not include all of the hydro generation at Holyoke, Hadley, and other sites in the Springfield area. The 2008 CELT lists about 57 MW at those sites, while about 27 MW are committed to provide capacity to the ISO in the summer of 2011. CL&P says that these smaller units are deducted from loads (IR OCC-48). I do not have the data necessary to confirm that assertion.

[19]"2010–2012 Massachusetts Joint Statewide Three-Year Electric Energy Efficiency Plan," National Grid, NStar, Western Massachusetts Electric, Unitil, and Cape Light Compact, April 30, 2009; Boston: Massachusetts Energy-Efficiency Advisory Council. I computed these percentages from the savings on p. 62 and from the 2009 CELT forecast.

[20]Appendix A shows 8 MW of additional passive load reduction in 2011 and roughly 1,245 MW of load prior to that reduction.

### B. *Generation Levels*

**Q: What factors determine which units operate at any time?**

A: First, the generation unit must be in service; that is, construction must be complete and the unit must not have been retired or shut down on a long-term basis.[21] The units in service in the summer of 2014 will be those in service in 2009, plus the units that are added between 2009 and 2014, minus any units that are retired or mothballed.

Not all units that are in service in 2014 will be available to operate in any particular hour. In most weeks of the year, some generation will be unavailable because it is shut down for scheduled maintenance; the ISO schedules that maintenance in low-load periods, to maximize reliability. As a result, no maintenance is scheduled for the summer, and no maintenance outages should be expected for the summer of 2014.

In addition to scheduled maintenance, some units will be unavailable, or only partially available, due to unplanned problems and equipment failures. Those periods of unavailability are called forced outages, and the percentage of time that a unit is forced out of service is called its forced-outage rate.

The ISO dispatches the remaining available plants to minimize cost and maintain reliability.

**Q: How does the ISO determine which units it will tell to operate in any hour?**

A: Each generating unit (and each importer) provides the ISO with a set of bids, stating the price at which the generator will start up and operate at various output levels. The ISO selects the lowest-priced generators that will collectively

[21] Long-term shutdown, lasting years and usually requiring months to return the unit to service, is often called "mothballing" or "deactivation."

meet the region's energy requirement considering a number of factors, including the following:

- The time and costs required for units to ramp up and down, to warm up and come on line, to cool off before restarting, and the like.
- Transmission constraints and losses. The ISO sometimes must run a more expensive generator in Connecticut and turn down a less-expensive unit in Maine, because the power could not get out of Maine, or perhaps could not get into Connecticut.
- System flexibility. The ISO must have generators running that can automatically adjust their output level within seconds to respond to changes in load and in output from other plants, as well as capacity that can ramp up or down over minutes as load changes. Just as importantly, the system must have operating reserves, ready to quickly start up if a generator or transmission line fails.

Even with these complications, the units that the ISO has operating at any time are generally those with the lowest fuel and other running costs, with the following consequences:

- Nuclear, wind, and trash-burning plants run whenever they are available;
- Coal and biomass plants run almost all the time;
- Efficient gas-fired combined-cycle plants operate most of the time;
- Older, less-efficient combined-cycle and steam plants operate in a minority of hours;
- Peaking units (mostly combustion turbines) operate a few hours to a few hundred hours.

**Q: Are CL&P's dispatch examples appropriate?**

A: No. The purpose of the dispatch cases is to represent situations in which the transmission system might be stressed. To be useful, however, those hypothetical cases need to be reasonable. Obviously, if CL&P were to model a situation in which every generator in Connecticut and western Massachusetts were unavailable, the transmission system would be highly stressed. But that situation is so unlikely that no one could credibly argue for building enough transmission to accommodate it.

For the Springfield area, Table 1 of the Addendum identifies 877 MW of capacity as follows:

- The Mt. Tom coal plant
- The MassPower and Berkshire Power combined-cycle plants
- West Springfield 3, an oil- and gas-fired steam plant
- Three peaking combustion turbines at West Springfield—the modern units 1 and 2, and the older jet
- The Cobble Mountain hydro plant.[22]

In addition, the dispatch details list 6 MW of generation at "SPGFLD PF," which appears to be the Springfield refuse plant and 3 MW at "Holyoke," which appears to be some of Holyoke's municipal-utility generation.

Of the subset of generation modeled by CL&P, dispatch D2 assumes that all that generation is on line, including the West Springfield jet, a very expensive unit that rarely runs. In dispatch D3, CL&P shuts down two of the four largest units in the area: the MassPower plant and Mt. Tom, representing about 44% of

[22]Table 1 in the Addendum is the same as Table 1 in the Application. In some lists of Springfield-area plants, including Table 1, CL&P includes Stony Brook, but that unit is attached to the transmission system in way that does not seem to help with the overloads addressed in the Application or Addendum. Cobble Mountain is listed at 17 MW in the Application, but at 33 MW in the ISO's CELT, and is committed to supplying 31 MW through 2011.

its recognized Springfield-area capacity.[23] In dispatch D1, CL&P shuts down three of the four large units—Berkshire Power, Mt. Tom and West Springfield 3, totaling 60%—and the West Springfield peakers, for another 10% of the local capacity.[24]

**Q: How realistic are the Springfield-area dispatches for extreme-peak summer conditions?**

A: These dispatches are highly unlikely. Under the conditions assumed in CL&P's analysis, all four of the large Springfield-area units would be operating, if they are available. None of these units should be out for maintenance at the system peak. Forced outage rates average about 5% for New England generation; for an older steam unit like West Springfield 3 or Mt. Tom, the outage rate might be closer to 10%.[25] Even at the higher 10% forced outage rate, the probability of two units being out at the same time (as in dispatch D3) is about 1%, and the probability of three units being out at the same time (as in dispatch D1) is about 0.1%. Since the extreme weather conditions used in CL&P's analysis are only expected one year in ten, the combination of that high load and dispatch D3 would be expected about once every thousand years, and the combination with dispatch D1 would be expected about once every ten thousand years. Other combinations of outages would give similar results, but the outage rates for the newer units are likely to be lower than 10%, so the probability of these levels of

[23]This dispatch also does not include the West Springfield jet.

[24]As I will discuss below, having these peaking units off-line at the beginning of the analysis should not increase transmission overloads following a contingency, since they would start up following the contingency.

[25]In OCC-55, CL&P refers to "Re-activation of 304 MW of Springfield generation that was previously assumed to be retired," suggesting that some of the dispatch cases assume retirement of some Springfield-area units. Such retirement would be subject to ISO reliability review.

stress on the transmission system may be slightly higher or lower. In any case, these dispatch scenarios would be very stringent tests of the transmission system.

In addition, the Addendum (p. 5) complains of overloads before any transmission outages in Scenario D1, in which Mt. Tom, Berkshire Power and all four West Springfield generators are off line simultaneously. The obvious response to outages of three major units at super-peak conditions would be to operate the West Springfield peakers. The Springfield-area dispatch in Scenario D1 is thus too unrealistic to be support any determination of need.

**Q: Are the Connecticut dispatches reasonable?**

A: Looked at in isolation, the Connecticut dispatches are plausible, although a surprisingly large amount of capacity is treated as being turned off, considering that the dispatches are supposed to represent extreme-peak conditions. CL&P assumes that some steam units (Norwalk Harbor 1 and 2, Montville 5 and 6) and various peaking units would be turned off in all scenarios. Middletown 2 and 4 are turned off in D1, D2, and D3, but turned on for D1-1700 (along with some extra peakers and Bridgeport Harbor 2) to replace the 800-MW reduction in imports to Connecticut. In D1, Bridgeport Harbor 2 and peakers replace Middletown 3, which operates in all the other scenarios.

In scenarios D1, D2, and D1-1700, the three units at the Lake Road combined-cycle plant are off line. Since Lake Road is an efficient modern combined-cycle gas plant, it would be operating on an extraordinarily-high-load summer peak, if it were available. Of course, like any unit, Lake Road could experience a forced outage.

While the dispatch of the Connecticut units could be plausible in itself, the comparison with the dispatch of Connecticut oil- and gas-fired steam plants with those in other states is very odd. While CL&P assumes that large amounts of the Connecticut oil- and gas-fired steam capacity are off line, it nonetheless runs almost all the oil- and gas-fired steam plants in other states. Only Wyman 2 and Wyman 3 are off line in scenarios D1, D2, and D3, joined by Wyman 4 in scenario D1-1700.

**Table 2: Addendum-Scenario Dispatch, Connecticut and Other New England Oil-Gas Steam Plants**

| | **D1** | **D2** | **D3** | **D1-1700** | **Capacity** (2009 CELT) |
|---|---|---|---|---|---|
| *Connecticut Plants* | | | | | |
| Bridgeport Harbor 2 | 131 | | | 131 | 130.5 |
| Middletown 2 | | | | 117 | 117.0 |
| Middletown 3 | | 236 | 236 | 236 | 236.0 |
| Middletown 4 | | | | 400 | 400.0 |
| Montville 5 | | | | | 81.0 |
| Montville 6 | | | | | 407.4 |
| New Haven Harbor | 448 | 448 | 448 | 448 | 447.9 |
| Norwalk Harbor 1 | | | | | 162.0 |
| Norwalk Harbor 2 | | | | | 168.0 |
| *Other New England Plants* | | | | | |
| Wyman 1 | 50 | 50 | 50 | 50 | 52 |
| Wyman 2 | | | | | 51 |
| Wyman 3 | | | | | 116 |
| Wyman 4 | 636 | 636 | 636 | | 603 |
| Newington | 422 | 422 | 422 | 422 | 400 |
| Mystic 7 | 565 | 565 | 565 | 565 | 578 |
| Salem 4 | 400 | 400 | 400 | 400 | 437 |
| Brayton Point 4 | 421 | 421 | 421 | 421 | 435 |
| Canal 1 | 566 | 566 | 566 | 566 | 573 |
| Canal 2 | 577 | 577 | 577 | 577 | 545 |
| Mason 3 | 33 | 33 | 33 | 33 | Retired |
| Mason 4 | 33 | 33 | 33 | 33 | Retired |
| Mason 5 | 33 | 33 | 33 | 33 | Retired |
| New Boston 1 | 350 | 350 | 350 | 350 | Retired |
| New Boston 2 | 380 | 380 | 380 | 380 | Retired |

Since the market price of power would tend to be higher in Connecticut than in other states when Connecticut is importing maximum amounts of power, the ISO generally would dispatch units in Connecticut *before* dispatching similar units in the other states. The operation of so much oil- and gas-fired steam generation in Massachusetts, New Hampshire, and Maine, when relatively little of that generation is operating in Connecticut, is odd. When asked about another inconsistency in the Application dispatch, CL&P basically replied that its dispatch scenarios are designed to stress the transmission system, not to be realistic (IR OCC-54).

A more-serious problem is that CL&P assumes the dispatch in 2014 of several Maine and Massachusetts generators that actually have been retired for years.[26] Both New Boston units and all three Mason units are retired; New Boston 2 was permanently shut down after being damaged by a fire in 2002, the Mason units were retired about 2004, and New Boston 1 was retired in 2007. None of these plants has offered capacity in the Forward Capacity Markets. Without some 800 MW of generation at these plants, it is not clear that the ISO could produce enough energy to force a Connecticut import of 2,500 MW, under the peak conditions CL&P assumes for the transmission analyses. Hence, CL&P's dispatch scenario is not only unlikely, it is actually *impossible.* No close approximation of those dispatches may be possible.

**Q: Might some generators be retired or mothballed by 2014?**

A: Yes. All of the generators in the Springfield area or Connecticut have committed to supply capacity to the ISO through May 2012, which is as far forward as the ISO has acquired capacity.[27] None of these generators has indicated an interest

[26]In the Application, CL&P also modeled the long-retired Devon 7 and 8 as operating. After being asked about that error on discovery, CL&P corrected that error in the Addendum.

[27]The one exception is Norwalk Harbor 2, which apparently tried to game the capacity-auction system and wound up with no contract for 2010–11. Norwalk Harbor 2 committed to provide capacity in 2011–12 at a price lower than the price it declined for 2010–11.

in deactivating. There are two mechanisms for doing so: requesting a reliability review (as Mystic 7 and Wyman 1 & 2 have done) or filing a high-price static delist bid in the forward capacity auction (as Somerset 6, Somerset jet, and Salem 1–4 have done). So in addition to the units that have already retired, CL&P's dispatch runs include seven units (Mystic 7, Wyman 1, Somerset 6 and Salem 1–4) that have expressed serious interest in deactivation, totaling about 1,200 MW. The ISO has approved the shutdown of Mystic 7 and Somerset 6; the latter, a 100 MW coal plant, has consistently bid the highest allowed prices and thus was not selected in the first two auctions, will not be selected in the third auction, and probably cannot return to service unless and until it is repowered.

**Q: Is it possible that some Connecticut units would abruptly retire and create a sudden reliability problem?**

A: No. The ISO can prohibit units from shutting down (or even leaving the capacity market) for reliability reasons, as it did for Norwalk Harbor in the 2010–11 capacity auction.[28] Similarly, the ISO has denied Wyman 1 and 2 permission to shut down until the 115-kV system to which they are attached is reinforced.[29]

If large amounts of capacity seek to shut down in some future year, Connecticut can then consider whether it is better to pay the units to stay on line, to build new generation, to reduce load further in the targeted areas, to build new transmission or to undertake some combination of those options. That

[28]Since the Norwalk Harbor units both accepted prices in the second FCA lower than the price they demanded in the first FCA, it appears that the plant's owner was attempting to game the pricing system.

[29]"Need for Yarmouth 1 for System Reliability," unpublished document; Holyoke, Mass.: ISO New England, May 27 2009.

decision should be made in a full integrated resource plan process, in which the CEAB and DPUC can consider all aspects of the alternatives.

**Q: How do CL&P's dispatches vary when Meriden and/or Towantic is added to the dispatch?**

A: The company simply removes an equal amount of other generation, leaving transmission flows unchanged (IR OCC-57a). Furthermore,

> The dispatch of Montville #6 and Bridgeport Harbor #2 were not based on economics. The dispatch of these units was based on removal of equivalent generation capability to that of Meriden or Towantic. This dispatch and simulation approach resulting in the Connecticut capacity and the Connecticut Import interface transfer level remaining approximately the same. (IR OCC-058)

Given the way that CL&P has formulated the scenarios, forcing 2,500 MW or (in the case of reduced transmission capacity) 1,700 MW of imports into Connecticut, no amount of capacity could change the results of CL&P's analysis.

*In other words, CL&P has designed the scenarios to create the appearance of a problem that the GSRP can solve.*

**Q: What would actually happen if hundreds of megawatts of new combined-cycle generation were added in Connecticut?**

A: If CL&P's scenarios represented reasonable operation of the generation system with currently committed resources, the addition of Meriden, Towantic, and/or other resources with low variable costs (e.g., nuclear, coal or renewables) would mean that more power would be produced in Connecticut on peak days, the imports into Connecticut would drop, and the existing transmission system—without GSRP—would have more capacity available, with which it could compensate for outages.

### *C. New England Imports and Exports*

**Q: What level of imports from Canada into northern New England does CL&P assume in its dispatch scenarios?**

A: In each of the scenarios, CL&P assumes imports of 1,004 MW from New Brunswick, 200 from Hydro Quebec through the Highgate station in Vermont, and 2,000 MW from Hydro Quebec through the HVDC lines into New Hampshire and Massachusetts.

**Q: Are those reasonable assumptions?**

A: Not entirely. The Highgate import levels are typical, but the other imports are extraordinarily high.

The maximum import level from New Brunswick to New England was about 700 MW, and the average level in the summer peak hours was about 260 MW in 2008.[30] For the 2009 Regional Supply Plan, the ISO is assuming that the New Brunswick import is limited to 1,000 MW for 2009–2018.[31] So CL&P assumes this import to be at its maximum level.

The transfer that CL&P assumes from Hydro Quebec over the HVDC lines is higher than both historical levels and the ISO's own assumptions. The maximum import level in 2008 was about 1,800 MW and the average level in the summer peak hours was about 1,400 MW.[32] For the 2009 Regional Supply Plan, the ISO assumes that the HQ HVDC import is limited to 1,400 MW.

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[30] A new line was added between New Brunswick and Maine in December 2007 and would be reflected in the 2008 import levels.

[31] Mezzanotte, Frank; "Transmission Transfer Limits for Transportation Models (to be used for 2009 analyses)" draft power-point presentation for March 31 2009 meeting of ISO-NE Planning Advisory Committee in Westborough,. Mass.; Holyoke, Mass.: ISO New England. Slide 5.

[32] The Hydro Quebec DC line is physically capable of carrying 2,000 MW, but an outage of the line when it is operating at that level could cause transmission problems throughout the Northeast,

In total, CL&P assumes imports from Canada that are hundreds of megawatts more than plausible import levels. A more realistic dispatch, without these excess imports and without the retired power plants, clearly would result in lower imports into Connecticut and less stress on the Springfield-area transmission lines. Lower stress on the Springfield-area lines would result in smaller overloads following contingencies, reducing the problems that the GSRP is intended to solve.

**Q: What level of imports from New York does CL&P assume in its dispatch scenarios?**

A: The company assumes no imports from New York. Depending on supply and demand conditions, New York and New England regularly exchange hundreds of megawatts of power in either direction. In the peak hours of the summer of 2008 (between 1 and 5 pm weekdays), interchange ranged from imports of 819 MW into New England to exports of 1,268 MW to New York. (These values exclude flows to and from Long Island.) At the 2008 peak (June 10 from 4 to 5 pm), New England was exporting some 324 MW to New York. I have not found any public data on the share of these transfers that flow over the two transmission lines from New York to Connecticut, as opposed to those to Massachusetts and Vermont.

**Q: What level of exports does CL&P assume in its dispatch?**

A: The company assumes that 352 MW of power are flowing out of Connecticut to Long Island on the Cross-Sound line.

**Q: Is that realistic?**

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so imports are usually limited to much lower levels. The ISO generally treats the DC line as providing 1,400 MW of firm supply.

A: The export is slightly exaggerated. The actual maximum export level has been about 332 MW. Average summer levels are lower and the export at the 2008 summer peak hour was 300 MW.

## IV. Response to Transmission Outages

**Q: When a transmission contingency occurs, how does the ISO respond?**

A: The ISO redispatches the system to maintain reliable service and minimize costs. In some cases, that would include changing transmission system settings directly. In most cases, the ISO would change the mix of generation serving load in the region.

In the case of a loss of transmission in western Massachusetts, increasing loadings on lines into Connecticut, the ISO would do as much of the following as necessary to maintain reliability:

- Increase the output of operating generation,
- Start up generators that are available for quick-start reserve,
- Request additional imports from New York into western Connecticut,
- Reduce exports to Long Island,
- Reduce generation and imports north of the transmission constraint to rebalance load and supply.

While the ISO would start on these measures immediately, it would have 30 minutes to bring the flow on the lines under their long-term-emergency ratings.

**Q: Would those options be available?**

A: Yes.

To maintain system reliability, the ISO maintains operating reserves, as a combination of the following:

- *Spinning 10-minute reserve:* units that are either already generating, but at less than full capacity, or are ready to generate and can ramp up very quickly. As CL&P notes, hydro units can provide spinning reserves (IR OCC-43)
- *Non-spinning 10-minute reserves:* mostly combustion-turbine peakers.
- *Thirty-minute operating reserves:* mostly combustion-turbines that start up more slowly than the 10-minute reserve units.
- *Replacement reserves:* generators that cannot be on line fast enough to qualify as 10-minute or 30-minute reserves, but are available to start up to replace any fast-start reserve units that are dispatched.

The ISO says that "The locational reserve requirements reflect the need for 30-minute contingency response to provide second-contingency protection for each import constrained Reserve Zone" (ISO Operating Procedure 8, Operating Reserve and Regulation, p. 7).

By 2014, Connecticut will have about 1,300 MW of combustion-turbine and diesel peakers in service. Under legislative guidance, the DPUC found that adding about 433 MW of new combustion turbines would be cost-effective for Connecticut ratepayers, in addition to the 858 MW existing in 2008, and instructed CL&P and UI to contract with those plants to ensure that they would be completed and available when needed.[33] At $145/kW-yr, Connecticut

[33]The new plants are Waterbury, Devon 15–18, Middletown 11, and New Haven Harbor. Municipal ratepayers are paying for the Pierce combustion-turbine, which CMEEC brought on line in 2007 to provide reserves, among other services. The market has not been adding enough capacity in Connecticut; utility and regulatory intervention was necessary to bring this capacity on line.

ratepayers would be paying over $60 million annually under the peaker contracts.[34]

In each hour, the ISO selects generators to leave idle, or below their maximum output, to provide operating reserves. CL&P mentions withholding generation to maintain operating reserves in IR OCC-43. The ISO's 2007 Annual Markets Report describes its approach to maintaining reserves regionally and in reserve zones (including Connecticut) as follows:

> In real time, resources are dispatched in the least-cost way to simultaneously meet the system's requirements for electric energy and reserves…. The dispatch software [chooses] whether transmission should be used to carry electric energy or reserves when satisfying zonal reserve requirements…. Zonal reserve requirements may be met by resources within the reserve zone and by resources outside the reserve zone through the unused import capability of the reserve zone transmission interface. (2007 Annual Markets Report, ISO-NE, pp. 87–88)

> When the system is redispatched to maintain reserves, the output of an inexpensive energy resource is decreased and the output of a more expensive, but slower, resource is increased.…This happens at the systemwide level, when systemwide reserve constraints are preserved, and at the level of local reserve zones, when local reserve constraints are involved. (p. 88)

> [System operators can also] limit the energy imports into the reserve zone [to] keep the remainder of the interface available for reserve (i.e., external reserve support). Inside the zone, more expensive energy units are dispatched to make up for the loss of energy imports. (pp. 89–90)

The second paragraph above explains how the ISO prevents Connecticut from getting into a situation in which not enough reserves are available to respond to a contingency, like those that CL&P assumes in its model runs. If Connecticut were facing a situation in which it might not have enough reserve capacity available to ramp up output following a transmission contingency, the

[34] DPUC Order in Docket No. 08-01-01, 6/25/08. p. 9.

ISO would start up additional “slow” plants—mostly the oil- and gas-fired steam units—and turn down (or off) some of the currently-operating “fast” plants—combustion turbine peakers, hydro, and some of the capacity of steam and combined-cycle units that are already running. In CL&P’s D1 scenario, that might involve some combination of the following actions:

- turning down the Shepaug and Stevenson hydro units (70 MW total);[35]
- turning off some of the 317 MW of operating peakers at Devon, Pierce, Wallingford, Waterbury and Waterside;
- reducing generation from some of the combined-cycle plants (Bridgeport Energy, Kleen, and Milford);
- bringing on some combination of the 1,570 MW of idle steam plants at Middletown, Montville, and Norwalk Harbor.

As the last paragraph in the quote explains, the ISO also limits transfers between zones (such as into Connecticut) if necessary to maintain reserves. So if insufficient fast resources were available to act as reserves, the ISO would bring on more slow resources in Connecticut, to reduce load on the transmission lines and allow the lines to provide some of the reserve.

**Q: Does the ISO have any mechanism for ensuring that enough reserve capacity will be available when needed?**

A: Yes. The ISO operates a seasonal forward auction for reserves, which acquires at least 1,550 MW system-wide, and aims to acquire at least 1,145 MW in Connecticut. There have not been enough quick-starting peakers in Connecticut to meet this target, so the ISO purchases all reserves offered in Connecticut. In exchange for these locational-forward-reserve-market payments, the generators

[35] These units can store water from one day to be used later in the week, so no potential energy output is lost by reducing their output.

agree to remain in reserve and not generate unless either prices reach the costs of running the most-expensive combustion turbines or the ISO calls on them for reserves.

**Q: Are there specific reserve targets for the Springfield area?**

A: No. There is no fixed target, as there is for Connecticut and some other areas. The ISO has a general requirement that reserves be maintained in various locations to deal with "any probable contingency."

> Operating Reserve shall be distributed to ensure that it can be fully utilized by ISO for any probable contingency without exceeding transmission system limitations and to ensure operation in accordance with NERC, NPCC, and ISO Manuals, operating policies and procedures. (ISO Operating Procedure 8, Operating Reserve and Regulation, p. 7)

In other words, the ISO has committed to maintaining reserve in the Springfield area, among others, to be able to respond to contingencies in that area.

In the Application, CL&P recognizes that the ISO dispatches power plants to maintain reserves sufficient to meet two contingencies in a row:

> West Springfield unit #3 and Berkshire Power, have been frequently designated as daily second-contingency units. These generators, in addition to West Springfield unit #1 and #2, are also needed to support local reliability during peak hours and to avoid overloads…. (Application p. F-26)[36]

**Q: Does CL&P design its dispatch cases so that operating reserves would be available to meet contingency conditions?**

A: Yes.

[36] In discovery, CL&P admitted that the Berkshire Power combined-cycle plant would be economic to operate and is not actually designated as a second-contingency unit (IR OCC-39).

> In the detailed transmission system planning studies which accompanied its application, NUSCo demonstrated compliance with OP-8 [ISO-NE Operating Procedure No. 8, "Operating Reserve and Regulation"] by maintaining fast-start generation in reserve throughout New England. The generation dispatch summaries contain a listing of the generators that were not dispatched prior to a transmission system contingency…. The ISO-NE has identified four New England areas where specific market considerations are enforced to meet operating reserve requirements. These areas include southwest Connecticut, Connecticut, the Boston area and the rest of New England. The greater Springfield area is included within the category "the rest of New England". The dispatches developed for the GSRP analyses are consistent with and comply with national and regional planning standards, Operating Procedure No. 8, and ISO-NE's area-specific operating reserve requirements. (IR OCC-47)

*In sum, CL&P ensures that reserve capacity is ready to respond to outages in its pre-contingency dispatch, but CL&P does not use that capacity when a contingency occurs.*

**Q: Would the ISO be able to reduce the exports to Long Island to preserve reliable service and avoid overloading transmission lines?**

A: Yes. The ISO must approve any application to commit capacity to export markets. So far, the only such request has been for 100 MW of exports to Long Island over the Cross-Sound Cable. The ISO has approved that export for 2010–2012, but the ISO can reject the sale in future years if it appears to be inconsistent with New England reliability standards. Even the 100-MW capacity sale can be terminated if necessary to maintain adequate reserves (IR OCC-67).[37]

**Q: Has CL&P explained why it includes 350 MW of exports in all its scenarios?**

[37]The North American Electric Reliability Corporation (NERC) specifically allows transmission models to assume the interruption of exports: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm electric power transfers" (Standard TPL-003-0, p. 5). See IR OCC-45 for a description of NERC's role in setting reliability standards.

A: No. When asked why Cross-Sound exports were reduced to 100 MW only as a "sensitivity" in its analysis of the Meriden and Towantic projects, CL&P responded by repeating that it included the 350 MW as its base case, without offering any justification (IR OCC-61).

**Q: What about other imports or exports to New York?**

A: If New England is selling power to New York over the other Connecticut–New York ties at the time of a critical transmission outage into Connecticut, the ISO can reduce or terminate that export, relieving stress on the lines into Connecticut. Whether the ISO can call on New York for additional support in other situations depends on the supply and demand balance in New York.

**Q: How does CL&P model this system of generation reserves and flexible transactions?**

A: The company completely ignores all of these real-world responses to real transmission outages. Once a transmission line fails, CL&P's analysis holds all generation, import, and export levels constant. In essence, CL&P assumes that the ISO would fail to start or to ramp up any of the generation reserves, would not request aid from New York, and would continue the export to Long Island, even as overloaded lines melt, circuit breakers open, and the lights go out in Western Massachusetts and Connecticut.

These CL&P assumptions, consistently used in its modeling, are highly unreasonable and help lead to misleading, non-credible conclusions on the company's part. Repeated inquiries to CL&P, concerning the post-contingency dispatch results in its analyses, finally elicited from the company the clarification that it does not change dispatch in its model after a transmission contingency (IR OCC-049-SP01).

The dispatch that CL&P specifies is so unrealistic that it entails large overloads in Maine (up to double the line capacity) and Vermont (around 40% over capacity), in both the base case and with many contingencies.[38]

**Q: Has CL&P offered any rationale for assuming unrealistic dispatch and failing to start any reserves in response to a transmission outage?**

A: Not really. In discovery, CL&P repeatedly states that the generation dispatches are intended to stress the transmission system, and that stressing the transmission system is required by the standards of various transmission organizations (e.g., IR OCC-39, 41, 42, 47, 49-SP01 and 51). Nowhere does CL&P cite any requirement or recommendation that modeling include stresses that would only result from prohibited levels of imports, the dispatch of retired power plants, or violation of operating-reserve policies, nor that post-contingency-dispatch modeling should ignore the ISO's realistic response to a transmission contingency. Indeed, one of the standards that CL&P cites requires realistic conditions: "Transfer capability studies shall be based on the load and generation conditions *expected to exist* for the period of study" (IR OCC-039, emphasis added).

Both CL&P (IR OCC-51) and the ISO (in refusing to provide any data on the operation of reserve units in IR OCC-64 and 65) cite reliability standards as follows: "Design studies shall assume power flow conditions utilizing transfers, load and generation conditions which stress the system," and that require the ISO to test the system "with due allowance for generation maintenance and forced outages, design studies will assume power flow conditions with applicable transfers, load and resource conditions that *reasonably* stress the

[38] The results are from CL&P's runs for the CEAB, since CL&P does not provide loading data for transmission outside Western Massachusetts.

system" (emphasis added). These standards do not require CL&P to assume impossible conditions to stress the system, nor to assume that the ISO will fail to follow its own established procedures for maintaining reserves or dispatching them following a contingency.

The company defends its failure to model any response to transmission outages by asserting, "It is not typical to model a specific re-dispatch after each of hundreds of modeled contingencies" (IR OCC-49-SP01). It does not appear that "a specific re-dispatch" would need to be defined for each of the 56 contingencies listed in the Addendum. CL&P does not consider the details of its dispatch cases to be significant outside the Springfield area, and suggests that any dispatch of Connecticut and other New England generation is as good as another, so long as the stress on the Connecticut import is the same. In most cases, the re-dispatch could consist of turning on 1,000 MW of generation in Connecticut, starting the peakers around Springfield (and bringing any other available plants up to full power), curtailing the Cross-Sound export, and turning down an equal amount of imports and generation in the rest of New England.[39] If a problem remains after the generic redispatch, CL&P could examine the feasibility of solutions with a more realistic redispatch.

**Q: Do some transmission studies assume redispatch of generation following a contingency?**

A: Yes. For example, in the "NYISO/PJM—Focused Study" of the Northeast Coordinated System Plan (presented at the Inter-Area Planning Stakeholder Advisory Committee meeting, June 30 2009, slide 21): "After each single

[39]The reductions in supply in the rest of New England might include reducing the Quebec import to the 1,400 MW transfer level and eliminating the non-existent Mason and New Boston units from CL&P's model.

contingency, all control equipment is allowed to adjust including re-dispatch in preparation for the next contingency."

**Q: Would adding any amount of generation anywhere change the results of CL&P's analyses?**

A: Apparently not. Consistent with its approach to date, in constructing these analyses, it is likely that CL&P would simply turn off a similar amount of capacity in a similar location, as it did for Meriden and Towantic.

**Q: Would adding capacity actually improve reliability?**

A: Yes. Adding Meriden or Towantic, or other generation, would allow the ISO to reduce imports, increase exports, shut down the quick-start generation that operate in the Application scenarios, or reduce the level of generation from units on line. All of these changes would leave the ISO with more flexibility in responding to a transmission outage, by reducing loading on the lines from Massachusetts to Connecticut, giving the ISO the ability to reduce exports, start quick-start reserve units, and ramp up the units on line.

## V. Reliability Results with More Realistic Dispatch

**Q: Had CL&P modeled normal post-contingency responses, would the post-contingency loads on the transmission system have been much lower?**

A: Yes. If necessary, the ISO could eliminate the Cross-Sound export, reducing load by 352 MW. In addition, some 1,100–1,500 MW of quick-start reserves would be available in Connecticut and up to another 110 MW in the Springfield area.[40] CL&P assumes that some of the Connecticut quick-start reserves (280

[40]The Cobble Mountain hydro unit operates about 15 MW below full power in all dispatch scenarios, and unused capacity at the West Springfield peakers is 93 MW in scenario D1 and

MW in dispatches D1, D2, and D3; 433 MW in dispatch D1 1700) would be operating in the pre-contingency dispatch. The ISO would dispatch those units for energy only if it had adequate reserves without them.

The only case that CL&P has run that even approximates the effect of system responses to contingencies is the scenario run for the CEAB and provided in IR OCC-55. This is the only case in which Connecticut resources are added without simply reducing the output of other Connecticut resources. CL&P complains that the CEAB case includes "extreme counter-factual assumptions" (IR OCC-12); to the contrary, the key CEAB assumptions (e.g., reduced Connecticut imports, additional generation from peaking units, and curtailment of the Cross-Sound export) are more realistic for post-contingency conditions than any of CL&P's scenarios.[41]

In this CEAB case, which is only partially optimized, transmission overloads are greatly reduced and limited to the 115-kV system around Springfield. CL&P reduced the output of the Springfield-area plants in this case, running each unit at MassPower, West Springfield 3, and Mt. Tom at about half power (about 232 MW, compared to their capacity of about 487 MW) and does not show any operation of the Springfield-area peakers. The remaining overloads might well be resolved by assuming a realistic dispatch of the Springfield-area generation for extreme peak conditions and in response to the transmission outages.

Indeed, the Addendum (p. 3) states,

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D1-1700 and 17 MW in D3. Some of capacity at smaller storage hydro plants in Connecticut may be available as spinning reserve.

[41]The CEAB case assumes higher loads than the current forecast, which would tend to increase transmission loadings.

> generators in the Springfield area, particularly the Berkshire Power and the West Springfield stations, have a significant impact on transmission circuit loadings in the area. When operating, these units serve local area load requirements and offer some protection from overloads following contingency events…. This protection comes, however, at a price. If their operation is the only way to address certain contingencies, local service and local reliability become dependent on generators that may need to be dispatched out-of-merit. Accordingly, if the Springfield 115-kV transmission system were not upgraded, these "must run" generation conditions would persist. If the units were not running, the greater Springfield area would lack adequate flexibility to avoid overloads following certain contingency events.

In this discussion, CL&P makes a couple of important observations. First, operation of generation in the Springfield area helps avoid overloads on the Springfield 115-kV transmission system. The overloads of that system in the CEAB case would probably be reduced by operating that generation.

Second, local reliability may require dispatching generators "out of merit order," that is, running a plant more than it would run for simple economic reasons. That is not likely to be a significant factor at peak, since most of the Springfield generation would be economic to run at peak hours. Only West Springfield 3 is likely to require significant out-of-merit dispatch, since Berkshire Power and MassPower would be economic to operate unless loads were very low (in which case the transmission system would not be loaded heavily) and the peakers can be offline and still start quickly enough to "avoid overloads following certain contingency events."

Third, the existing system can maintain local reliability by keeping local units available for dispatch and actually running them as necessary. The Addendum is correct that "This protection comes at a price." That price might include paying some fixed costs of West Springfield 3, to ensure that it remains available on line and/or sometimes paying some costs of running West

Springfield 3 out of merit.[42] That price must be compared to the costs of local transmission upgrades to maintain reliability within the Springfield area. This appears to be an issue that should be resolved among the ISO, Western Massachusetts Electric, the various Springfield-area municipal utilities, and Massachusetts authorities.

**Q: Does it appear that a fully realistic response to transmission contingencies would avoid all overloads?**

A: That cannot be determined from the runs that CL&P has performed. Some problems might remain in the Springfield-115 kV system, which would seem to require some work in Massachusetts to improve the local transmission system, reduce load, or increase generation.

## VI. CL&P Incentives Regarding Transmission Expansion

**Q: Does CL&P have any reason to favor transmission where no new resource is needed, or favor transmission over other resource solutions?**

A: Yes. In the state's restructured electric industry, CL&P generally cannot participate in generation solutions. If it were allowed to offer a generation alternative, it would have to compete with many other suppliers; when CL&P was required to compete in the DPUC's peaker procurement, it was not successful. CL&P does have a major role in deploying energy-efficiency solutions, but those costs are basically flowed through to ratepayers with limited opportunity for CL&P to earn any profit. In transmission, and particularly in the

[42] Those costs would be borne by the Western Massachusetts Electric Company, as the transmission owner, and be paid by the transmission users in Western Massachusetts and/or central Massachusetts (IR OCC-39(d)).

GSRP, CL&P and its affiliates are the dominant players. Transmission investments are large and long-lived, and CL&P is well positioned to earn a continuing return on that investment.

Transmission is also a particularly lucrative investment. Utilities are allowed to earn higher return from transmission investment than from other investments.

- In its last *distribution* rate case, the DPUC allowed CL&P an equity return of 9.4% (Docket No. 07-07-01).

Transmission rates are regulated by the FERC, rather than the DPUC, and FERC allows much higher profit levels on transmission investments.

- The FERC generally allows an equity return of 11.64% for existing transmission in New England (Docket No. ER08-1548-000, November 17, 2008, 125 FERC 61,183, ¶82).
- FERC allowed even an higher 12.64% return on new transmission projects approved in the ISO's Regional Transmission Plans, through December 2008 (ER04-157-014, March 24, 2008, 122 FERC 61,265, ¶51).
- FERC allows a still higher 12.89% equity return on NEEWS-related projects (Docket No. ER08-1548-000, ¶82).

Normally, a high allowed or target return would be associated with a high-risk investment, where the investor has a significant chance of low or no return. This is not true for FERC-regulated transmission. FERC has rarely found any transmission or generation investment to be imprudent or otherwise unrecoverable. For NEEWS projects, FERC permits transmission owners to start charging customers for investments as they are made, rather than waiting for project completion and operation, and guarantees recovery of expenditures even if the project is abandoned.

Part of the job of utility management is to look for opportunities to increase shareholder return without increasing risk. Considered in that light, an investment in transmission, and particularly in a part of NEEWS, would be difficult to resist. *While the bias of utility managers toward transmission is understandable, it is important to recognize that the most profitable actions for shareholders are not necessarily the best for ratepayers.*

The company has compared this proceeding to a “cage fight” between CL&P and the potential developers of generation: “Two or more competitors go into [the regulatory review], but no more than one may come out” (Letter from Anthony M. Fitzgerald to S. Derek Phelps, April 14 2009, p. 3). It is unfortunate that CL&P appears to have abandoned its responsibility to provide reliable service at the lowest reasonable cost, and instead is struggling with generation developers for the opportunity to maximize profits.

But one point in CL&P’s cage-fight analogy is apt. As CL&P notes at the end of its cage-fight analogy, about the fate of contenders, “Sometimes none will come out.” At this point, no need has been demonstrated for any project to be approved.

**Q: Does this conclude your testimony?**

A: Yes.