Northeast Utilities System

107 Selden Street, Berlin, CT 06037

Northeast Utilities Service Company
P.O. Box 270
Hartford, CT 06141-0270
(860) 665-5000
www.nu.com

June 26, 2009

Mr. S. Derek Phelps
Executive Director
Connecticut Siting Council
10 Franklin Square
New Britain, CT 06051

Re: Docket No. F-09 - Connecticut Siting Council Review of 2009 Forecasts of Electric Loads and Resources

Dear Mr. Phelps:

This letter provides the response to requests for the information listed below.

Response to CEAB-01 Interrogatories dated 06/11/2009
CEAB-001, 002, 003, 004, 005, 006, 007, 009, 010, 011, 012, 013, 014, 015, 016, 017, 018, 019, 020, 021, 022, 023, 024

KHP

Very truly yours,

Christopher R. Bernard

Christopher Bernard
Manager
Regulatory Policy - Transmission
NUSCO
As Agent for CL&P

cc: Service List

OS3422 REV. 01-00

Witness: Robin E. Lewis
Request from: Connecticut Energy Advisory Board

Question:
Please provide a detailed description of the methodology by which the energy and peak load forecasts contained in your initial filing in this proceeding were prepared.

Response:
Several regression models are used to develop CL&P's forecast of monthly sales, reflecting local economic and demographic conditions. Economic and demographic forecasts for the state of Connecticut are based on a model developed by Moody's Economy.com in November 2008 for the state of Connecticut and the United States. The sales forecast is developed by class by various end uses that affect energy consumption and incorporates assumptions to reflect customers' response to price changes, conservation programs, distributed generation and other known changes. Sales forecasts provide input to the hourly load, output and peak load forecasts. The output forecast is equal to the sum of the class sales forecasts plus delivery losses. The peak forecast is based on a regression model that uses sales as a driver. These models are all described in more detail below.

Sales Forecasts

The residential and commercial models are each comprised of a customer model to forecast customer counts, a statistically adjusted end-use model ("SAE") to forecast use per customer, and an elasticity model which provides price and economic elasticities that are used in the SAE.

Step 1: Residential and Commercial Customer Models

The residential customer forecast was estimated using historical data from January 1999 to August 2008 with residential customer counts as a function of households and a 12 month lagged dependent variable. The commercial customer forecast is based on nonmanufacturing employment, as well as both 12 month and 1 month lagged dependent variables. It was estimated using historical data from January 1990 through August 2008.

Step 2: Residential and Commercial Elasticity Models

The residential elasticity model was estimated using historical data from January 2003 to August 2008. The commercial elasticity model was estimated using historical data from January 2000 to August 2008. The functional forms of these models are:

$\mathbf{ResUsePerDay}_m = f(HDD\_RD_m, CDD\_RD_m, Price_m, Income_m,)$
$\mathbf{ComUsePerDay}_m = f(HDD\_RD_m, CDD\_RD_m, Price_m, GSP_m,)$

where:
m = Month
HDD_RD_m = Heating degree days per reading day per month
CDD_RD_m = Cooling degree days per reading day per month
$Price_m$ = 12 month moving average real typical bill per month
$Income_m$ = Monthly real average personal income per household
GSP_m = Monthly real gross state product for the service producing sector

The coefficients of the price terms are used to calculate point elasticities for each month, depending on the relationship of the actual or projected price to the mean price. Thus a higher forecasted price would give a higher price elasticity. The equation for the point elasticities is:

$\mathbf{PriceElas}_m = CoefPrice * Price_m / MeanPred_m$

where:
m = Month
CoefPrice = Coefficient on the price term in the elasticity model
$Price_m$ = 12 month moving average real typical bill per month
$MeanPred_m$ = Predicted value calculated from $Price_m$ and the mean value of all other independent variables

The range of point elasticities derived from the residential equation is -.127 to -.220 and the commercial equation is -.109 to -.198. The mean income and GSP elasticities are used throughout the estimation and forecast period because generally, average income and GSP change gradually from one period to the next with little variation in the point elasticities. The average elasiticities used were .151 for income and .362 for GSP.

Step 3: Residential and Commercial SAE Models

The SAE model uses regional end-use data from the U.S. Department of Energy's Energy Information Administration to develop independent variables that are used in traditional econometric models.

The SAE modeling framework begins by defining energy use ($Use_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$\mathbf{Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m}}$$

Although monthly sales for individual customers is available from billing data, the end-use components of those sales are generally not readily available. Substituting the estimates defined above for the unknown actual end-use usage gives the following econometric equation:

$$\mathbf{Use_{y,m} = b_1 \times XHeat_{y,m} + b_2 \times XCool_{y,m} + b_3 \times XOther_{y,m}}$$

Here, $XHeat_{y,m}$, $XCool_{y,m}$ and $XOther_{y,m}$ are explanatory variables constructed from end-use information, dwelling, weather, economic and price data and the income and price elasticities derived from Step 2. The equations used to construct these X-variables maintain an end-use structure as the X-variables are the estimated usage levels for each of the major end uses. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors which scale the regional data to the Company's sales.

For the residential and commercial classes, trend sales equal the number of customers times use per customer derived from steps 1 and 3.

Step 4: Industrial, Streetlighting and Railroad Sales Forecasts

The industrial, streetlighting and railroad sales forecasts are based on traditional econometric models because SAE models and the required data are not available for these classes. The functional forms for these models are:

$\mathbf{IndSales}_m = f(CDD_m, RD_m, Price_m, Employment_m)$
$\mathbf{StlUse}_m = f(MonBinary_m, Time_m)$
$\mathbf{RRSales}_m = f(LagDependent_m)$

where:
CDD_m = Cooling degree days per month
RD_m = Reading days per month
$Price_m$ = 12 month moving average real typical bill per month
Employment = Manufacturing employment
$StlUse_m$ = Streetlighting use per residential customer
MonBinary = Monthly binary variables
LagDependent = 12 period lagged dependent variable

Industrial and railroad trend sales are derived directly from the econometric models. Streetlighting trend sales are equal to the model-produced use per residential customer from Step 4 times the number of residential customers from Step 1.

Step 5: Adjustments to Forecast

The final step in developing the Reference case forecast is to make adjustments to the Trend forecast to account for Conservation and Load Management reductions, Distributed Generation reductions, Large Commercial and Industrial gains or losses, and a final adjustment to convert billed sales into calendar sales. The end result is the Reference forecast.

Peak Load Forecast

The Reference peak load forecast is primarily used for allocating NU's operating expenses among the operating companies and it is not used for system planning purposes. (The ISO-NE forecast is used for transmission system planning.) CL&P's forecasted peaks are derived from an econometric model where monthly peaks are a function of weather, Reference forecast sales per reading day, and weather trends which capture increasing air conditioning load. Since the C&LM and economic development assumptions are already included in Reference sales, which the peak demand forecast is a function of, no explicit adjustments are made to the peak model-produced results. However, this year the model-produced summer peak was reduced by 182 MW in each year of the forecast, to account for the ISO-NE Load Response program. The functional form for this model is:

$$\mathbf{Peak}_m = f(SalesPerRD_m, HDD_m, CDD_m, YestCDD_m, HDDTrend_m\ CDDTrend_{m,}\ THITrend_{m,})$$

where:
$Peak_m$ = Monthly peak load
$SalesPerRD_m$ = Total retail sales per reading day per month
HDD_m = Heating degree days on day of monthly peak
CDD_m = Cooling degree days on day of monthly peak
$YestCDDd_m$ = Cooling degree days on the day before the monthly peak day
$HDDTrend_m$ = Heating degree days on day of monthly peak interacted with time
$CDDTrend_m$ = Cooling degree days on day of monthly peak interacted with time
$THITrend_m$ = Temperature Humidity Index on day of monthly peak interacted with time
Time = Year + month/12
THI = 0.4 * (dry bulb temperature + wet bulb temperature) + 15)

The Reference or 50/50 peak forecast assumes normal weather throughout the year, with normal peak-producing weather episodes in each season. The forecasted mean daily temperature for the summer peak day is 83° Fahrenheit ("°F") and is based on the average peak-day temperatures from 1977-2006.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-002

Witness: David J. Bebrin
Request from: Connecticut Energy Advisory Board

Question:
Please provide the number of MW and customers in your service territory that are currently enrolled in ISO-NE Demand Response Programs.

Response:
CL&P currently has 413 customers enrolled in ISO-NE's 30 Minute Demand Response program representing 188 MW. CL&P does not have any customers enrolled in ISO-NE's 2 Hour Demand Response Program. CL&P does not have information on the quantity of customers or MWs of demand response capacity that may be enrolled by third party vendors in CL&P's service territory.

Witness: David J. Bebrin
Request from: Connecticut Energy Advisory Board

Question:
Please provide the number of MW and customers in your service territory that (a) cleared in FCA2 as a real-time demand response or profiled response customer, or (b) cleared in FAC2 as an "other demand resource" (ODR) customer.

Response:
The information provided pertains to CL&P assets cleared or enrolled in the ISO-NE FCA-2 and does not include CL&P customers that are Demand Response (DR) or ODR assets for third party vendors.

A. Real Time Demand Response (both with and without Emergency Generation) has 164 MW of cleared capacity which will be met with the existing 413 customers described in CL&P's response to CEAB Set 1, question 2. The 164 MW represents capacity cleared in FCA-1 since no new capacity was bid into FCA-2. This capacity represents load as measured at the customer meter. (Note: The 188 MWs referenced in CEAB Set 1, question 2 is the latest current capacity based on the August 22, 2008 Event Performance).

B. ODR - Energy Efficiency On Peak Demand Resource has cleared capacity of 160 MW for FCA-2. This includes existing capacity of 98 MW plus FCA-2 new capacity in the amount of 62 MW. This capacity represents load as measured at the customer meter.

ODR - Distributed Generation On Peak Demand Resource has cleared capacity of 28 MW for FCA-2. This includes existing capacity of 12 MW plus FCA-2 new capacity in the amount of 16 MW. This capacity represents load as measured at the customer meter.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-004

Witness: Robin E. Lewis
Request from: Connecticut Energy Advisory Board

Question:
Please describe and show the calculations underlying the load factor forecasts found in CL&P's Table 2-1, UI's Exhibit 1, and CMEEC's Table 1.

Response:
The load factor shown in CL&P's Table 2-1 is derived by the following equation using output of the load model and peak model results.

Load Factor = (Output / 8760 Hours)/ Seasonal Peak.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-005

Witness: Allen W. Scarfone
Request from: Connecticut Energy Advisory Board

Question:
Please provide a copy of your ten-year plan for infrastructure improvements in Connecticut.

Response:

CL&P's 2009 Forecast of Loads and Resources report for the period 2009-2018 dated March 2, 2009 contains infrastructure improvements planned by CL&P in Chapter 4, Section 4.7, Pages 32 through 42.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-006

Witness: Allen W. Scarfone
Request from: Connecticut Energy Advisory Board

Question:
Please indicate which of the transmission improvements described in your initial filings in this proceeding are to serve planned or anticipated generating facilities.

Response:

There are no transmission facilities in the CL&P 2009 Forecast of Loads and Resources (FLR) report solely for the interconnection of generating facilities. The proposed transmission improvements in the CL&P FLR are needed to reliably integrate generation and load in accordance with national and regional reliability standards and criteria. The projects in the FLR are not solely planned for the interconnection of any specific generating facility. Transmission facilities needed to reliably interconnect a generator to the New England transmission system are identified in accordance with the ISO-NE Tariff.

Witness: David J. Bebrin
Request from: Connecticut Energy Advisory Board

Question:
Please compare your assumptions for CL&M impacts in both your 50/50 and 90/10 cases, in terms of MWh and peak MW savings, to the levels in the Reference Case and Expanded Energy Efficiency in Connecticut Case described in the electric distribution companies' 2009 IRP Filing submitted January 1, 2009.

Response:
Attached is a Table comparing the C&LM annual savings used in the 2009 Forecast of Loads and Resources (FLR), the IRP Reference Case, and the IRP Expanded Case. The C&LM savings is the same for both the 50/50 and the Extreme Hot Weather Scenario cases (FLR does not present a 90/10 scenario). Note that the Table shows annual savings without half year factors (Half year factors take into account that measures are installed throughout the year). Also note, the presentation of savings in the FLR and IRP are cumulative. Since the forecast period is different for the two reports, the annual savings are being presented for direct comparison.

Annual Savings Comparison

Year	Energy (GWH) 2009 Forecast March 2, 2009	Energy (GWH) Reference Case IRP	Energy (GWH) Expanded Case IRP	Capacity (MW) 2009 Forecast March 2, 2009	Capacity (MW) Reference Case IRP	Capacity (MW) Expanded Case IRP
2009	203	N/A	N/A	29	N/A	N/A
2010	339	339	387	52	52	60
2011	331	331	505	52	52	79
2012	305	305	486	50	50	79
2013	286	286	476	48	48	79
2014	274	274	467	47	47	79
2015	262	262	444	44	44	75
2016	250	250	421	42	42	72
2017	239	239	400	41	41	68
2018	228	228	380	39	39	65

The Connecticut Light and Power Company
Docket No. F-09

Witness: David J. Bebrin
Request from: Connecticut Energy Advisory Board

Question:
Please provide the effective Load Factor for C&LM programs described on in your 2009 Filing for both history and forecast , and compare to the system-wide Load Factor shown in Exhibit 1.

Response:
The attached Table compares the annual load factors to the load factors of the efficiency savings.

CEAB-9 Load Factor Comparison

Load Factors (1)

	Reference Plan (50/50 Case) (2)	Extreme Hot Weather Scenario (2)	Extreme Cool Weather Scenario (2)	Annual Efficiency Savings (3)
HISTORY NORMALIZED FOR WEATHER				
2004	0.576			0.597
2005	0.552			0.505
2006	0.560			0.624
2007	0.546			0.690
2008	0.537			0.728
FORECAST				
2009	0.541	0.494	0.597	0.803
2010	0.531	0.484	0.587	0.742
2011	0.523	0.476	0.579	0.725
2012	0.516	0.469	0.572	0.698
2013	0.505	0.458	0.560	0.685
2014	0.496	0.449	0.551	0.672
2015	0.484	0.439	0.538	0.671
2016	0.482	0.436	0.537	0.671
2017	0.476	0.430	0.531	0.671
2018	0.470	0.424	0.525	0.671

1. Load Factor = Output (MWH) / (8760 Hours X Season Peak (MW)).
2. Values from table 2-1 2009 Forecast of Loads and Resources, March 2, 2009
3. Load Factor = Savings (MWH) / (8760 Hours X Summer Peak Savings (MW)).

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-010

Witness: David A. Errichetti
Request from: Connecticut Energy Advisory Board

Question:
Please provide a list of imports, with a detailed description of each, that would be reduced or eliminated by low capacity market prices in the reference case, other than the 641 MW economic import (Erie Boulevard Hydropower) via New York A/C ties referenced on pp. 1-2 and 1-17 of the 2009 IRP filing, and addressed on page 29 of CL&P's 2009 Forecast of Loads and Resources filing (CL&P filing).

Response:
None of the other capacity imports into New England modeled in the electric disribution companies' 2009 IRP filing would be assumed to be reduced or eliminated by low capacity prices.

Witness: Allen W. Scarfone, David A. Errichetti
Request from: Connecticut Energy Advisory Board

Question:
Please provide a detailed explanation of why in the CL&P filing NEEWS is assumed to be needed because it will increase import capacity from 30% to 45% of the state's peak load (pp. 28, 31) if low capacity market prices are expected to reduce or eliminate major import resources over the reference case forecast horizon, as referenced in the preceding question.

Response:

The NEEWS Projects are a comprehensive set of transmission facilities that address reliability problems in the southern New England region. These reliability problems were identified by ISO-NE to be transmission system delivery deficiencies in Rhode Island and the greater Springfield area and the restrictive ability to move large blocks of power between eastern and western New England in a secure manner. Included, were concerns over the capability of the Connecticut Import interface to import sufficient amounts of electric power following a contingency event and the ability of the Connecticut transmission system to reliably move that power from east to west across the state. As part of the benefits of the NEEWS projects the Connecticut Import interface transfer limit increases from approximately 30% to 45% of the state's peak load.

The preceding question refers to capacity imports to New England, not Connecticut. Import capacity at pp. 28 and 31 of the Company's forecast refers to capacity in the sense of hourly energy flows, but also has a bearing on how much capacity needs to be located in Connecticut to meet resource adequacy requirements.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-012

Witness: Allen W. Scarfone
Request from: Connecticut Energy Advisory Board

Question:
Please quantify from the scenario analyses referenced on p. 32 of the CL&P filing the financial impact of the reduction in "instances of Reliability Must Run ("RMR") and other congestion charges that are related to transmission system limitations" brought about by the advent of NEEWS.

Response:

CL&P has not completed any financial analyses to determine the impact of the NEEWS projects on the need to run generation out of merit due to transmission constraints. As indicated in our FLR filing it is well documented that there are RMR contracts for generators in the greater Springfield area and in Connecticut. The NEEWS projects are first designed to reliably serve customer peak demands for electricity. Another benefit of increased transmission capability is the elimination or reduction in the need to run RMR units in a local area. Transmission improvements such as those proposed by NEEWS can mitigate the need to run RMR units in Connecticut and the Springfield area. In addition, the NEEWS Projects increase the Connecticut Import interface limits along with those between eastern and western New England. This increase in transmission capability reduces the need to rely upon less efficient and environmentally challenged Connecticut generation during high and peak load periods.

On June 17, 2009 ISO-NE reiterated again during a Planning Advisory Committee meeting that reducing dependence on out-merit-generation is an outcome that frequently accompanies transmission system reliability projects.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-013

Witness: David J. Bebrin, Bryan C. Barbera
Request from: Connecticut Energy Advisory Board

Question:
Please explain how the Distributed Generation and C&LM impact in MWs shown in Table 2-2 of the CL&P filing differ from the Expanded Energy Efficiency in Connecticut scenario referenced on p. 1-20 of the 2009 IRP filing. Please provide the data annually in the following form (a) total system energy requirements, (b) summer peak, (c) for total C&LM, (d) conservation impacts only, and (e) load management impacts only.

Response:
Attached is CL&P's Table with the expanded energy efficiency case from CL&P's and UI's 2009 IRP. It should be noted that the distributed generation and demand response numbers did not change since the 2009 CL&P and UI IRP Expanded Case considered only an increase in energy efficiency.

CEAB-013: Adjustments to Output and Summer Peak Forecasts

Net Electrical Energy Output Requirements

		2009 FLR March 2, 2009					Expanded IRP		
Year	Unadjusted Output GWH a	Distributed Generation GWH b	ISO-NE Load Response GWH c	Company Sponsored C&LM GWH d	Total Company Sponsored C&LM GWH e=c+d	Adjusted Output GWH f =a+b+e	Company Sponsored C&LM GWH g	Total Company Sponsored C&LM GWH h =c+g	Adjusted Output GWH I = a+b+h
HISTORY NORMALIZED FOR WEATHER									
2008						24,467			24,467
FORECAST									
2009	24,449	(231)	-	(68)	(68)	24,150	(81)	(81)	24,137
2010	24,568	(341)	-	(316)	(316)	23,910	(371)	(371)	23,856
2011	24,913	(378)	-	(652)	(652)	23,883	(797)	(797)	23,738
2012	25,270	(379)	-	(974)	(974)	23,917	(1,295)	(1,295)	23,596
2013	25,255	(378)	-	(1,272)	(1,272)	23,605	(1,778)	(1,778)	23,099
2014	25,363	(378)	-	(1,555)	(1,555)	23,429	(2,252)	(2,252)	22,733
2015	25,585	(378)	-	(1,824)	(1,824)	23,383	(2,711)	(2,711)	22,496
2016	25,901	(378)	-	(2,082)	(2,082)	23,441	(3,147)	(3,147)	22,376
2017	26,056	(378)	-	(2,328)	(2,328)	23,350	(3,561)	(3,561)	22,116
2018	26,279	(378)	-	(2,563)	(2,563)	23,338	(3,955)	(3,955)	21,946

Normalized Compound Rates of Growth (2008-2018)
0.7%

Reference Plan (50/50 Case)

		2009 FLR March 2, 2009					Expanded IRP		
Year	Unadjusted Output MW	Distributed Generation MW	ISO-NE Load Response MW	Company Sponsored C&LM MW	Total Company Sponsored C&LM MW	Adjusted Output MW	Company Sponsored C&LM MW	Total Company Sponsored C&LM MW	Adjusted Output MW
HISTORY NORMALIZED FOR WEATHER									
2008						5,184			5,184
FORECAST									
2009	5,306	(20)	(182)	(10)	(192)	5,094	(12)	(194)	5,092
2010	5,397	(29)	(182)	(46)	(228)	5,139	(56)	(237)	5,130
2011	5,523	(32)	(182)	(98)	(280)	5,211	(122)	(304)	5,187
2012	5,642	(32)	(182)	(150)	(332)	5,278	(201)	(383)	5,227
2013	5,751	(32)	(182)	(199)	(381)	5,337	(280)	(462)	5,256
2014	5,858	(32)	(182)	(246)	(428)	5,398	(360)	(542)	5,284
2015	6,021	(32)	(182)	(292)	(474)	5,514	(438)	(620)	5,369
2016	6,092	(32)	(182)	(336)	(518)	5,542	(512)	(694)	5,366
2017	6,191	(32)	(182)	(378)	(560)	5,598	(582)	(764)	5,394
2018	6,301	(32)	(182)	(418)	(600)	5,669	(649)	(831)	5,438

Normalized Compound Rates of Growth (2008-2018)
2.0%

Extreme Hot Weather Scenario

		2009 FLR March 2, 2009					Expanded IRP		
Year	Unadjusted Output MW	Distributed Generation MW	ISO-NE Load Response MW	Company Sponsored C&LM MW	Total Company Sponsored C&LM MW	Adjusted Output MW	Company Sponsored C&LM MW	Total Company Sponsored C&LM MW	Adjusted Output MW
HISTORY NORMALIZED FOR WEATHER									
2008						5,184			5,184
FORECAST									
2009	5,792	(20)	(182)	(10)	(192)	5,580	(12)	(194)	5,579
2010	5,897	(29)	(182)	(46)	(228)	5,640	(56)	(237)	5,630
2011	6,037	(32)	(182)	(98)	(280)	5,725	(122)	(304)	5,701
2012	6,170	(32)	(182)	(150)	(332)	5,806	(201)	(383)	5,755
2013	6,293	(32)	(182)	(199)	(381)	5,880	(280)	(462)	5,798
2014	6,414	(32)	(182)	(246)	(428)	5,954	(360)	(542)	5,840
2015	6,591	(32)	(182)	(292)	(474)	6,085	(438)	(620)	5,939
2016	6,676	(32)	(182)	(336)	(518)	6,126	(512)	(694)	5,950
2017	6,789	(32)	(182)	(378)	(560)	6,197	(582)	(764)	5,992
2018	6,913	(32)	(182)	(418)	(600)	6,281	(649)	(831)	6,050

Normalized Compound Rates of Growth (2008-2018)
2.9%

1. Sales plus losses and company use.
2. Load Factor = Output (MWH) / (8760 Hours X Season Peak (MW)).

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-014

Witness: David J. Bebrin
Request from: Connecticut Energy Advisory Board

Question:
Please provide the final ruling, if available, on approval of the 2009 C&LM plan, quantifying the impact on continued funding of the new C&LM programs included in the forecast period. If the ruling is available, please provide the ruling or docket citation and url link to the on line supporting documentation.

Response:
Please find below the internet address for the Final Decision for the 2009 Conservation and Load Management Plan (C&LM) issued by the Department on May 7, 2009. The Final Decision reflects an increase of $22.8 million of additional funding compared to the November 7, 2008 revised filing of the C&LM Plan. The increase in funding has the potential to result in 11 MW and 74 GWh of additional savings in 2009.

http://www.dpuc.state.ct.us/dockcurr.nsf/6eaf6cab79ae2d4885256b040067883b/847509afafc0d9e1852575b0005866f8?OpenDocument

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-015

Witness: David J. Bebrin
Request from: Connecticut Energy Advisory Board

Question:
If state funding has been reduced for the new C&LM programs please describe the other methods for replacement funding considered over the forecast horizon for the 2009 IRP and CL&P filing.

Response:
The state has not reduced funding for C&LM programs in this legislative session. Funding for C&LM programs are paid for by customers through a 3 mill charge pursuant to Conn. Gen. Stat. 16-245m as part of the "Combined Public Benefits Charge" on customers' bills. CL&P expects proceeds from the Regional Greenhouse Gas Initiative (RGGI) auctions, Forward Capacity Market revenues, and the sale of Class III Renewable Energy Credits to provide additional C&LM funding.

In addition, Connecticut may be receiving additional funding for conservation and energy efficiency programs from the US Department of Energy as a result of the American Recovery and Reinvestment Act (Stimulus Act). It should be noted that pursuant to the Stimulus Act, such funding cannot replace existing C&LM funding. If Connecticut wants to receive Stimulus Act funding, it cannot reduce the existing level of C&LM funding.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-016

Witness: David A. Errichetti
Request from: Connecticut Energy Advisory Board

Question:
Please identify and describe an potential new resources currently permitted but not under contract that could serve Connecticut's Local Sourcing Requirement, including the location, summer and winter MW rating and assumed load factor.

Response:
The Connecticut Light and Power Company is aware of proposals to build new generation in Meriden and Oxford, and that each project has received a Siting Council certificate of Environmental Compatibility and Public Need (certificate) in 1999. PDC El Paso LLC received the CSC certificate for Meriden and Calpine for Towantic Energy LLC for Oxford. Subsequently, each of these certificates was transferred to a new owner; NRG Energy Inc. for Meriden and GE Energy Financial Services for Oxford. The Company is unaware of the current status of each of these generation projects in regard to satisfying the conditions of the Council's certificate decisions, nor of the status of the many permits required from other agencies. The Company notes, however, that NRG Energy provided a listing of permits required for the Meriden facility, and the present status of each, in Section 10 of their March 19, 2009 application to the CT Siting Council, Docket 370B. The Company understands neither of these resources has received a contract through the Connecticut Capacity CfD effort, Connecticut peaker effort, or Project 150 effort. CL&P is not aware of any other proposals meeting the question's criteria. In the electric distribution companies' 2009 Integrated Resource Plan at page 1-12, the Meriden proposal is shown to have a 510 MW summer rating and the Oxford proposal, also known as Towantic, is shown to have a 489 MW summer rating. These ratings were based on information filed at FERC by ISO-NE relating to the second Forward Capacity Auction.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-017

Witness: Allen W. Scarfone
Request from: Connecticut Energy Advisory Board

Question:
Referring to the bar chart on p. 6 of the filing, please provide a similar chart showing in-state capacity of each state as a % of peak.

Response:

The Company has reviewed the results of the ISO-NE Forward Capacity Auction (FCA2) and compared them to the 2009 Capacity, Energy, Loads, and Transmission (CELT) report 90/10 summer peak demands for 2012. This comparison shows that in each New England state, the total MWs of generation capacity is at least equal to the peak demand.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-018

Witness: Robin E. Lewis
Request from: Connecticut Energy Advisory Board

Question:
Referring to p. 9 please provide a high and low economy driven peak and energy forecast rather than weather driven for the next 10 years.

Response:
The primary purpose of CL&P's peak forecast is to allocate NU's operating expenses among the operating companies for budgeting purposes and it is not used for system planning. (The ISO-NE forecast is used for transmission system planning.) CL&P has not developed high and low economic peak and energy scenarios and would be unable to do so in the short time period allowed, particularly without any guidance about how to define "high and low economy". However, the Company can offer some qualitative observations in lieu of quantitative analysis. Past studies have shown that weather and price-induced and/or Company-sponsored conservation have a far greater impact on both energy and peaks than the economy does. Extreme weather has the potential to impact energy by approximately 5% and peaks by approximately 10% in either direction. Although the elasticities on economic variables in the energy models are generally higher than price elasticities, the variability on economic data is generally less than the variability of electric prices, so the overall impact is less, perhaps about 1-3%. The impact on peaks is typically smaller still. For example, in the current recession, industrial sales have fallen dramatically, primarily because manufacturing firms have cut back on their second and third shifts. The summer peak is expected to be barely impacted in this case because the electricity usage of these firms is essentially unchanged during the first shift when the peak occurs. However, when energy prices soared a few years ago, business customers responded by replacing their old equipment with more energy-efficient equipment, which impacts both sales and peak loads and this year's forecast implicitly reflects lower usage and contribution to peak load for these customers. Summer peak growth is being driven primarily by higher penetrations of air conditioning in the residential class. Virtually all new homes now have central air conditioning. Despite sales declines in 2006 and 2008, peak load grew in these years because customers were willing to ignore the cost of air conditioning on the hottest summer days. It is expected that customers will react similarly on hot days during poor economic times.

The most important point about the effect of the economy on forecasting and system planning is this: system planning begins many years before the need arises. The economy will continue to cycle up and down as always. The current recession is unlikely to have much of an impact on long-term growth. The peak load forecasted to occur ten years from now may not occur until the eleventh or twelfth year, or there may be an economic boom or technological change that advances it to the eighth or ninth year, but it is expected to occur at some point in the normal planning horizon and it is prudent to plan for it.

Witness: Robin E. Lewis
Request from: Connecticut Energy Advisory Board

Question:
Referring to p. 10, please describe in detail the reference weather versus 90/10 weather that drive the differences in the peak demand forecast. Please show with historical data the 90/10 weather impact of 10% or more in a single year as discussed on page 11.

Response:
CL&P does not produce a 90/10 forecast. The Extreme Hot Weather Scenario that is shown in Table 2-1 is based on the weather on August 9, 2001, which was the hottest peak-load day that the Company has on record, from 1950 to the present. As described in the response to Q-CEAB-001, there are six weather variables in the peak model, four of which pertain to the cooling season and two that pertain to the heating season. The four cooling season weather variables are peak day cooling degree days ("CDD"), peak day cooling degree day trend ("CDD Trend"), CDD on the day before the peak day ("Yesterday CDD") and a maximum peak day temperature humidity index trend ("THI Trend"). The coefficients of these variables are the weather factors (MW per degree) that are used to calculate both the Reference Plan (the 50/50 Case) and the Extreme Hot and Cool Weather Scenarios. The trend variables include a time component which, in effect, causes the coefficients to increase over time to account for increasing penetrations of air conditioning. Page 2 of 3 shows the weather determinants and the calculation of the Extreme Hot Weather Scenario. The Reference Plan is based on normal weather, which is the average of the summer peak day weather for thirty years (1977-2006) for each of the four weather variables. The Extreme Hot Weather Scenario is based on the hottest summer peak day weather, which was August 9, 2001. The Extreme Cool Weather Scenario (Page 3 of 3) is calculated in the same way, using weather from the coolest summer peak day, which was June 27, 2000.

Calculation of Extreme Hot Weather Scenario Peaks

Weather Determinants

	(A) Model Coefficients (MW)	(B) Normal Weather (°F)	(C) Extreme Hot Weather (°F)	(D) = (C) - (B) Diff Between Normal and Extreme (°F)
CDD	38.84	83	88	5
CDD Trend	1.34	83	88	5
Yesterday CDD	14.74	80	86	6
THI Trend	1.81	83	87	4

Weather Sensitivities (MW per Degree from Coefficients)

	(E) Time Trend = Forecast Year - Base Year + Month/12	(F) CDD	(G) = (E)*(F) CDD Trend	(H) Yesterday CDD	(I) THI Trend
2009	14.6	38.84	19.61	14.74	26.44
2010	15.6	38.84	20.95	14.74	28.25
2011	16.6	38.84	22.29	14.74	30.07
2012	17.6	38.84	23.64	14.74	31.88
2013	18.6	38.84	24.98	14.74	33.69
2014	19.6	38.84	26.33	14.74	35.51
2015	20.6	38.84	27.67	14.74	37.32
2016	21.6	38.84	29.02	14.74	39.13
2017	22.6	38.84	30.36	14.74	40.95
2018	23.6	38.84	31.70	14.74	42.76

Peak Impacts of Extreme Weather (MW)

	(J) = (D) * (F) CDD	(K) = (D)*(G) CDD Trend	(L) = (D)*(H) Yesterday CDD	(M) = (D)*(I) THI Trend	(N) = (J)+(K)+(L)+(M) Total
2009	194	98	88	106	486
2010	194	105	88	113	500
2011	194	111	88	120	514
2012	194	118	88	128	528
2013	194	125	88	135	542
2014	194	132	88	142	556
2015	194	138	88	149	570
2016	194	145	88	157	584
2017	194	152	88	164	598
2018	194	159	88	171	612

Comparison of Peaks (MW)

	(O) Reference Peak (MW)	(P) = (O)+(N) Extreme Hot Weather Peak (MW)	(Q) = ((P)/(O)-1) *100 Pct Change
2009	5,094	5,580	9.5%
2010	5,139	5,640	9.7%
2011	5,210	5,725	9.9%
2012	5,278	5,806	10.0%
2013	5,337	5,879	10.2%
2014	5,397	5,954	10.3%
2015	5,514	6,085	10.3%
2016	5,541	6,126	10.5%
2017	5,598	6,197	10.7%
2018	5,669	6,281	10.8%

Calculation of Extreme Cool Weather Scenario Peaks

Weather Determinants

	(A) Model Coefficients (MW)	(B) Normal Weather (°F)	(C) Extreme Cool Weather (°F)	(D) = (C) - (B) Diff Between Normal and Extreme (°F)
CDD	38.84	83	76	-7
CDD Trend	1.34	83	76	-7
Yesterday CDD	14.74	80	79	-1
THI Trend	1.81	83	81	-2

Weather Sensitivities (MW per Degree from Coefficients)

	(E) Time Trend = Forecast Year - Base Year + Month/12	(F) CDD	(G) = (E)*(F) CDD Trend	(H) Yesterday CDD	(I) THI Trend
2009	14.6	38.84	19.61	14.74	26.44
2010	15.6	38.84	20.95	14.74	28.25
2011	16.6	38.84	22.29	14.74	30.07
2012	17.6	38.84	23.64	14.74	31.88
2013	18.6	38.84	24.98	14.74	33.69
2014	19.6	38.84	26.33	14.74	35.51
2015	20.6	38.84	27.67	14.74	37.32
2016	21.6	38.84	29.02	14.74	39.13
2017	22.6	38.84	30.36	14.74	40.95
2018	23.6	38.84	31.70	14.74	42.76

Peak Impacts of Extreme Weather (MW)

	(J) = (D) * (F) CDD	(K) = (D)*(G) CDD Trend	(L) = (D)*(H) Yesterday CDD	(M) = (D)*(I) THI Trend	(N) = (J)+(K)+(L)+(M) Total
2009	-272	-137	-15	-53	-477
2010	-272	-147	-15	-57	-490
2011	-272	-156	-15	-60	-503
2012	-272	-165	-15	-64	-516
2013	-272	-175	-15	-67	-529
2014	-272	-184	-15	-71	-542
2015	-272	-194	-15	-75	-555
2016	-272	-203	-15	-78	-568
2017	-272	-213	-15	-82	-581
2018	-272	-222	-15	-86	-594

Comparison of Peaks (MW)

	(O) Reference Peak (MW)	(P) = (O)+(N) Extreme Cool Weather Peak (MW)	(Q) = ((P)/(O)-1) *100 Pct Change
2009	5,094	4,617	-9.4%
2010	5,139	4,649	-9.5%
2011	5,210	4,708	-9.7%
2012	5,278	4,762	-9.8%
2013	5,337	4,808	-9.9%
2014	5,397	4,856	-10.0%
2015	5,514	4,959	-10.1%
2016	5,541	4,973	-10.2%
2017	5,598	5,017	-10.4%
2018	5,669	5,075	-10.5%

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-020

Witness: Allen W. Scarfone
Request from: Connecticut Energy Advisory Board

Question:
Referring to p. 16, how have the peaking contracts been taken into account in transmission planning, specifically with respect to NEEWS project need assessments.

Response:

The peaking contracts discussed on page 16 are modeled in the power-flow cases. However, the units are not dispatched in the base case because they are held in reserve to cover the loss of the largest generating unit on-line in the state of Connecticut.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-021

Witness: David A. Errichetti
Request from: Connecticut Energy Advisory Board

Question:
Please define generation fuel diversity addressing in particular, but limiting your response to, the following factors:

-- How is diversity calculated;
-- What is an acceptable mix for Connecticut;
-- Is diversity defined as fuel consumed or fuel that is setting the price at the margin;
-- Are there any company or state standards or policy objectives for fuel diversity.

Response:
Fuel diversity is not a defined term and can have different meanings depending on context. The request highlights two ways of defining fuel diversity but there is at least a third way, which is diversity to meet resource adequacy. In its broadest sense, "fuel diversity" means that generating plants, in aggregate, have a diverse mixture of fuel supply. The concept of fuel diversity has been part of utility planning for many years and continues to inform electricity infrastructure discussions today, as evidenced by this very question. In fact, with today's market structure being far removed from a planned and managed structure, one could argue that monitoring fuel diversity, however defined, is even more important today than in previous years. Fuel diversity, however defined, protects customers from the ups and downs, shortages and gluts, or weather impacts of any one particular fuel source creating both physical security and economic balance. Because there is no agreement on what fuel diversity means, it is not possible to define an acceptable mix. But even if what is meant by fuel diversity could be agreed to, there are other concerns with trying to establish a fuel supply mix for Connecticut. For instance, Connecticut load and resources are integral parts of the ISO-NE control area; as such is Connecticut the correct area within which to discuss mix or is it New England? Another consideration is Connecticut's renewable portfolio standards; they need not be met with Connecticut located generation so this calls into question the merits of defining a Connecticut-centric fuel mix.

The witness is not aware of any company or state standards on fuel diversity. The witness is not aware of state policy objectives on fuel diversity beyond those identified in CEAB's 2009 Comprehensive Plan for the Procurement of Energy Resources at page 38.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-022

Witness: David J. Bebrin
Request from: Connecticut Energy Advisory Board

Question:
Referring to pp. 23-24, what is the status of the EE Potential study the companies and ECMB have had prepared on their behalf. Please describe the reason for delay. Please describe in detail the approximate EE potential of the study.

Response:
CL&P has not received a final report on the EE Achievable Potential study as the final review and report completion was deferred to focus efforts on the completion of the C&I natural gas achievable potential study. The ECMB is in the process of reviewing final edits to the report. However, preliminary results estimate that a total of 1095 MW of peak load conservation savings (approximately 16% of existing load) and 5,910 GWh of energy savings (approximately 20% of existing usage) may be achievable under a 10 year accelerated conservation funding scenario. These totals are combined totals for CL&P and UI and include existing conservation efforts.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-023

Witness: Allen W. Scarfone
Request from: Connecticut Energy Advisory Board

Question:
Referring to p. 28, please list the top 20 contingencies i.e., transmission or generation, for Connecticut, both internal and the interconnection to from CT to the rest of the system.

Response:

We do not maintain a list of the top 20 system-wide contingencies. Rather, we develop contingency decks to test the strength of all parts of the system. The worst contingencies will vary, depending upon the area of the state being studied. However, in general, contingencies on the 345-kV system, will be worse than contingencies on the 115-kV system, because a 345-kV circuit carries significantly more power than a 115-kV circuit; double circuit tower contingencies on the 115-kV system will be worse than single circuit contingencies; and contingencies involving Millstone Unit 2 or 3 or other large generating units will be worse than contingencies involving smaller units.

The Connecticut Light and Power Company
Docket No. F-09

Data Request CEAB-01
Dated: 06/11/2009
Q-CEAB-024

Witness: Allen W. Scarfone
Request from: Connecticut Energy Advisory Board

Question:
Please provide the detailed status of the ISO-NE reassessment of Transmission projects especially NEEWS. Will the company ever consider withdrawing one or more of the NEEWS application should the needs assessment show an elimination or 10 year deferment of need for any component of the NEEWS projects.

Response:

All four of the NEEWS Projects received ISO-NE I.3.9 approval in 2008. ISO-NE has completed an updated review of the need for both the Rhode Island Reliability Project and the Greater Springfield Reliability Project and has reconfirmed that both Projects are needed as soon as they can be built. ISO-NE presented its conclusion, together with underlying analyses in its initial response to Data Request OCC-01, Q-OCC-16 in CSC Docket 370 dated April 16, 2009 and in its supplemental response dated May 19, 2009. On June 17, 2009, ISO-NE elaborated on theses conclusions at a meeting of its Planning Advisory Committee (PAC). The slides from that power point presentation contain CEII material and can be obtained on request by qualified participants.

At the June 2009 PAC meeting, ISO-NE also advised the Committee that, because of the complexity of the problems that the Interstate and Central Connecticut Reliability Projects address, it had not yet completed an updated analyses of these Projects. CL&P declines to speculate on the study results and possible impact on each of these Projects.

Pursuant to section 3.6(c) of Attachment K to the ISO-NE Transmission, Markets and Services Tariff, ISO-NE periodically updates the Transmission Project List in its Regional System Plan. Both the Interstate Reliability Project and the Central Connecticut Reliability Project are included in the most current RSP Transmission Project Listing. Pursuant to their obligations under Section 8 of Attachment K, CL&P, the Western Massachusetts Electric Company, and National Grid USA are continuing to plan, design, and permit these facilities.