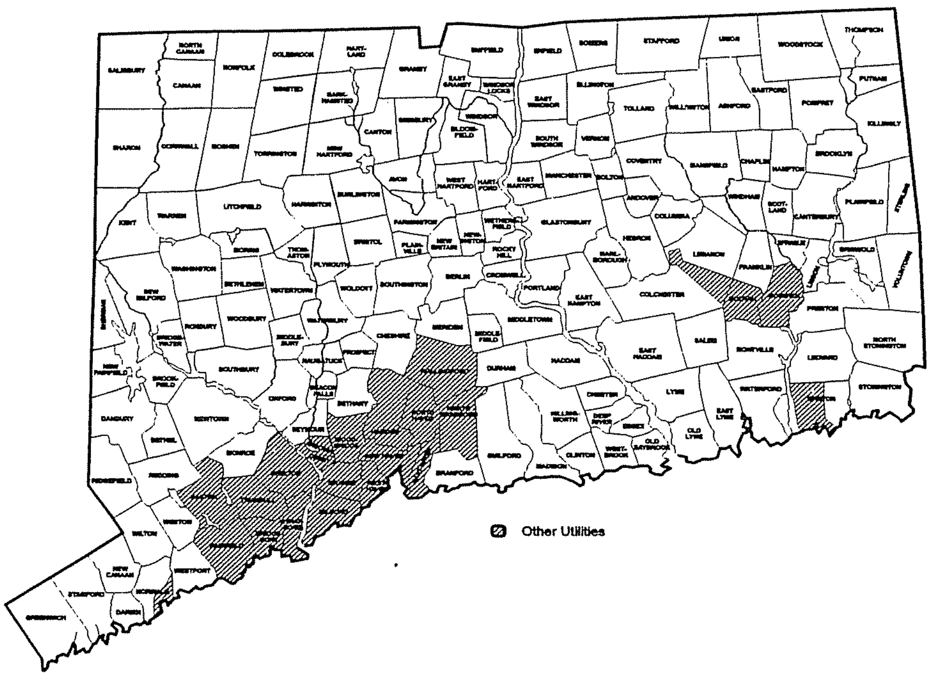
THE CONNECTICUT LIGHT AND POWER COMPANY

2005 FORECAST OF LOADS AND RESOURCES FOR 2005-2014



Northeast
Utilities System

March 1, 2005

Northeast Utilities System

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Stephen Gibelli
Senior Counsel

March 1, 2005

Ms. Pamela Katz, Chairman
Connecticut Siting Council
Ten Franklin Square
New Britain, CT 06051

Dear Ms. Katz:

Submitted herewith, on behalf of The Connecticut Light and Power Company, is an original and twenty copies of the annual report on loads and resources, as required by Section 16-50r of the Connecticut General Statutes.

This load and resource report is available for review by the public during normal business hours at the principal office of Northeast Utilities Service Company, Regulatory Planning Department, Selden Street, Berlin, Connecticut. Arrangements for viewing the Report can be made by calling Mr. Christopher R. Bernard at (860) 665-5967.

Please contact me if you have any questions with respect to this filing.

Very truly yours,

Stephen Gibelli

Enclosure
cc: Louise E. Rickard, DPUC

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EXECUTIVE SUMMARY

CHAPTER I

EXECUTIVE SUMMARY

A. Introduction

The Connecticut Light & Power Company ("CL&P") is an electric operating subsidiary of Northeast Utilities, the parent company of the NU system companies, collectively referred to as NU or the Company. NU is among the twenty largest electric utilities in the United States and the largest in New England, serving over 1.7 million customers in Connecticut, New Hampshire, and western Massachusetts. NU's other electric operating subsidiaries are Public Service Company of New Hampshire ("PSNH") and Western Massachusetts Electric Company ("WMECO").

This forecast of loads and resources is being submitted at a time when the landscape of the regional and national electric industry continues to undergo significant changes. Prior to the enactment of Public Act 98-28, resource planning was based on an electric public service company's statutory obligation to serve, with regulatory oversight of resource need projections as well as procurement of generation and conservation and load management ("C&LM") resources. Today, through the restructured electricity market, other parties determine how, when and where resources are utilized to meet customer needs. As customers are given choice in the selection of their electricity suppliers, long-term sales forecasting for competitive suppliers has become highly uncertain, resulting in a greater emphasis on short-term planning. The disaggregated ownership of supply resources has further complicated the planning process.

Transmission planning is now the responsibility of the Independent System Operator of New England ("ISO-NE") and has also been profoundly impacted by the transformation of the wholesale electric market. Customers in Connecticut are no longer served by regulated generation but by competitive merchant generation. The merchant generators requesting transmission service in New England, the uncertainty of stalled merchant generator projects, the location of new generation geographically distant from customer loads, and the potential for early retirement of generators based on environmental or economic reasons have added complexity to transmission planning. Further, the upcoming introduction of Locational Installed Capacity ("LICAP") will have a substantial effect on Connecticut's restructured electricity markets.

In 2004, the legislatively constituted Connecticut Energy Advisory Board ("CEAB") completed its first full year of activities, with the creation of preferential criteria for evaluating energy projects to be solicited through its authority, as of December 1, 2004, to issue requests for proposals ("RFP") under Public Act 03-140. CEAB is authorized to explore alternatives to the proposals made in applications to the Connecticut Siting Council ("CSC") for transmission lines, natural gas facilities, electric generation units or electric substations. In addition, CEAB has broad authority to issue RFP's in response to identified energy needs.

NU continues to work with the siting agencies, utility commissions, ISO-NE and others as the industry moves toward full wholesale and retail competition, to ensure that reliable, safe electric service is provided in an environmentally responsible manner.

Content and Organization of the Report

The five remaining chapters in this report contain: CL&P's forecast of energy requirements and peak loads through the year 2014; a discussion of CL&P's C&LM programs; information on CL&P's remaining generating resources; data on existing and planned NU system transmission facilities; and maps of the main electric systems in Connecticut.

B. CL&P Load Growth Projections

The forecast in this report is substantially identical to the forecast in CL&P's 2004 Forecast of Loads and Resources ("FLR"), with the exception that the 2004 forecast values have been replaced with actual data and 2014 forecast data have been included. However, it is important to note that although the Company uses its own forecast for financial planning, ISO-NE is responsible for regional transmission planning and develops its own aggregated demand forecast based on input from the individual utilities and states. This forecast is used for transmission planning.

CL&P is forecasted to remain a strongly summer peaking system over the ten-year forecast period. The reference plan forecast assumes that average peak-producing weather will be the most likely occurrence. However, as demonstrated in recent years, deviations from average peak day temperatures are random, recurring and unpredictable occurrences.

Chapter II includes exhibits that show the range of potential summer peaks around the reference plan due to weather. To illustrate, the 2014 reference plan summer peak forecast of 6,344 megawatts ("MW") is bounded by a high value of 6,864 MW and a low value of 5,896 MW. This range is solely based on potential peak-producing weather conditions.

Table I-1 summarizes CL&P's ten-year outlook for energy and peak load. Forecasted average growth rates are for the entire CL&P service area. Local growth rates may be substantially higher or lower. CL&P's energy growth is forecasted to have a compound annual growth rate of 2.0 percent over the 2004-2014 period.

This energy forecast reflects increased residential usage primarily due to more electric end uses and larger homes, moderate economic growth in Connecticut, gains from economic development, and savings from C&LM. Weather-normalized summer peak loads are forecast to grow 2.4 percent annually from 2004-2014.

TABLE I-1

CL&P
TEN YEAR OUTLOOK FOR ENERGY AND PEAK LOAD

	Reference Plan	
Year	Energy (Gigawatt-hour)	Summer Peak (MW)
2004 (actual)	25,496	4,818
2004 (normal)	25,578	5,020
2014	31,054	6,344
Compound Annual Growth Rates (2004-2014)		
Actual	2.0%	2.8%
Normalized	2.0%	2.4%

All data are for the total CL&P franchise area, including customers served by alternate energy suppliers.

A breakdown of the load forecast shows that over the next ten years (2005-2014), new C&LM programs could reduce peak growth by 0.3 percent per year. High economic growth could increase peak growth by 0.6 percent per year. Most significantly, if the 2001 peak weather were to recur in 2014, the actual peak could exceed the forecasted peak by over 500 MW.

C. CL&P Existing C&LM Resources

In 2005, CL&P continues to maintain its commitment to the development of energy efficient resources through its C&LM programs with a strong focus towards conservation efforts in southwest Connecticut ("SWCT"). Since the late 1980's, CL&P estimates its C&LM programs have reduced future capacity requirements by approximately 457 MW (Table III-1, Summer Impact).

D. Future C&LM Options

As in the forecast of energy output requirements and peak demand, many factors affect the level of energy and demand savings that actually occur in the forecast period. The savings projection is based on the historical relationship between expenditures and savings, adjusted for program changes as appropriate. A change in this relationship, a different economic climate, a change in the energy consumption appetite of CL&P customers, or a change in available C&LM funding would produce different levels of savings over the forecast period.

CL&P has made projections of the statewide savings that will result from C&LM program activity for the period 2005 through 2009.

E. Transmission System

Chapter V describes CL&P's transmission system expansion plans and the complexities associated with transmission planning in a restructured electric utility industry centered on an open access transmission system and a competitive generation marketplace. Since CL&P filed its FLR report last year, significant events have occurred that have a direct impact on transmission services in Connecticut, including ISO-NE's approvals to enter into contracts for the construction of an underground segment for the 345-kilovolt ("kV") Bethel – Norwalk Project and ISO-NE's transition to an independent Regional Transmission Organization ("RTO") on February 1, 2005. In addition, there have been continued ISO-NE changes to the regional transmission planning process and near-term changes to the competitive generation marketplace that all could have a substantial impact on electric service in Connecticut. Chapter V is intended to inform the CSC of these developments.

CHAPTER II

ELECTRICAL ENERGY DEMAND FORECAST

CHAPTER II

ELECTRICAL ENERGY DEMAND FORECAST

A. Introduction

The forecast contained in this chapter was prepared in January 2004 and is substantially identical to the forecast filed on March 1, 2004 in CL&P's 2004 FLR, with the exception that the 2004 forecast values have been replaced with actual data and 2014 forecast data have been included. The Trend Forecast and the Reference Plan are based on the total franchise area that CL&P serves, and do not include any assumptions about changing market share due to industry restructuring in Connecticut or elsewhere. The forecast excludes wholesale sales for resale and bulk power sales. Furthermore, this forecast does not include the updated C&LM savings projections that are shown in Chapter III of this report. CL&P's 2005 Economic and Load Forecast will be developed later this year and will be made available at that time to the CSC. Although this forecast is used for CL&P's financial planning, it is important to note that it is not used for transmission planning. The ISO-NE has responsibility for regional transmission planning and develops its own forecast independently which is used by CL&P for its transmission planning.

The exhibits in this chapter contain the Reference Plan Forecast and scenarios demonstrating the variability around the Reference Plan due to weather. The exhibits show that weather has a significant impact on the peak load forecast which induces up to eight percent variability, representing approximately 500 MW, above and below the Reference Plan, which is based on normal weather.

B. Energy Output and Peak Load Forecast

The Trend Forecast contains the results of the end-use models by customer class, unadjusted for forecasted CL&P's C&LM and economic development programs. It assumes normal weather based on a thirty-year average (1972-2001) of heating and cooling degree days and a reference case economic forecast. It also includes improvements to the efficiency of appliances that are mandated through legislation or building codes including the 1992 National Energy Act. The American Council for an Energy-Efficient Economy's (ACEEE) interpretation of these standards has been incorporated into the Trend Forecast.

The 2004 Trend Forecast projects a compound annual growth rate in total electrical energy output requirements of 1.7 percent for CL&P between 2004 and 2014.

The Reference Plan is the Trend Forecast plus additional kilowatt-hours ("kWh's") resulting from economic development programs minus energy savings due to CL&P's C&LM programs. The Reference Plan assumes that available funding in 2005 and 2006 will be lower than in the past because of the diversion of conservation funds to close the state budget gap and funding for new programs will continue through 2008. The ten-year compound annual Reference Plan growth rate for CL&P total electrical energy output requirements is 2.0 percent.

Table II-1 provides historic output and summer peaks for the 2000-2004 period, and forecast output and peaks for the 2005-2014 period. The peak load forecast is the maximum sum of the hourly forecasts of load for each customer class, company use and associated losses. The sum of the class hourly loads for each year, company use and associated losses is the annual forecast of system electrical energy requirements or output. This is the amount of energy which must be supplied by generating plants to serve the loads on the distribution system.

The 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 1972-2001. The historical peak day mean temperatures range from 76° F to 88° F with deviations from the average peak day temperatures being random, recurring and unpredictable occurrences. For example, the lowest peak day mean temperature occurred in 2000, while the highest occurred in 2001. This variability of peak-producing weather means that over the forecast period there will be years when the actual peaks will be significantly above or below forecasted peaks.

C. Forecast Scenarios

Table II-2 shows the reference summer peak forecast and the summer peak vulnerability solely attributable to high and low peak weather conditions. To illustrate, the 2014 summer peak forecast reflecting average peak-producing weather is 6,344 MW. However, either extremely mild or extremely hot weather indicates a range of potential peak loads from 5,896 MW to 6,864 MW. This 968 MW range, which is a band of about plus or minus eight percent around the average, demonstrates the potential impact of weather alone on forecasted summer peak demand. Extremely hot weather is unpredictable, yet the impact is immediate. A hot day in the first year of the forecast that matches the extreme peak day weather in 2001 could produce peak load demand greater than that forecasted for the fifth year under normal weather assumptions. Even a moderately hot day such as the 2002 peak day could increase peak demand by approximately 200 MW.

TABLE II-1
NORTHEAST UTILITIES SYSTEM
2004 LONG-RUN FORECAST
CONNECTICUT LIGHT AND POWER COMPANY

TOTAL FRANCHISE NET ELECTRICAL ENERGY OUTPUT REQUIREMENTS AND PEAK LOADS

REFERENCE PLAN

HISTORY 2000 - 2004
FORECAST 2005 - 2014

	NET ELECTRICAL ENERGY OUTPUT REQUIREMENTS (1)		SUMMER PEAK		
YEAR	OUTPUT	ANNUAL CHANGE	PEAK	ANNUAL CHANGE	LOAD FACTOR
	GWH	(%)	MW	(%)	(2)
HISTORY					
2000	24052		4433		0.618
2001	24352	1.2%	5126	15.6%	0.542
2002	24880	2.2%	5183	1.1%	0.548
2003	25190	1.2%	4980	-3.9%	0.577
2004	25496	1.2%	4818	-3.3%	0.602
2004 NORMALIZED			5020	0.8%	
COMPOUND RATES OF GROWTH (%) 2000-2004					
	1.5%		2.1%		
FORECAST					
2005	25947	1.8%	5288	9.7%	0.560
2006	26368	1.6%	5407	2.3%	0.557
2007	26738	1.4%	5481	1.4%	0.557
2008	27226	1.8%	5562	1.5%	0.557
2009	27636	1.5%	5667	1.9%	0.557
2010	28247	2.2%	5787	2.1%	0.557
2011	28887	2.3%	5919	2.3%	0.557
2012	29657	2.7%	6064	2.4%	0.557
2013	30303	2.2%	6209	2.4%	0.557
2014	31054	2.5%	6344	2.2%	0.559
COMPOUND RATES OF GROWTH (%) 2004-2014					
	2.0%		2.8%		
NORMALIZED COMPOUND RATE OF GROWTH (%) 2004-2014					
			2.4%		

1. SALES PLUS LOSSES AND COMPANY USE.
2. LOAD FACTOR = OUTPUT (MWH) / (8760 HOURS X SEASON PEAK (MW)).

Forecasted Reference Plan Peaks are based on normal peak day weather :
Peak Day Mean Daily Temperature = 83° F
Day Before Mean Daily Temperature = 81° F
Temperature Humidity Index = 83° F

Temperature Humidity Index = 0.4 * (dry bulb temperature + wet bulb temperature) + 15°

TABLE II-2
NORTHEAST UTILITIES SYSTEM
2004 LONG-RUN FORECAST
CONNECTICUT LIGHT AND POWER COMPANY

SUMMER PEAK VULNERABILITY DUE TO WEATHER

HISTORY 2000 - 2004
FORECAST 2005 - 2014

	SUMMER REFERENCE PLAN			SUMMER PEAK VULNERABILITY DUE TO WEATHER: HIGH				LOW			
Year	Peak MW	Annual Change (%)	Load Factor (1)	Peak MW	Annual Change (%)	Change from Ref MW	Change from Ref (%)	Peak MW	Annual Change (%)	Change from Ref MW	Change from Ref (%)
HISTORY											
2000	4433		0.618								
2001	5126	15.6%	0.542								
2002	5183	1.1%	0.548								
2003	4980	-3.9%	0.577								
2004	4818	-3.3%	0.059								
2004 WEATHER NORMALIZED:	5020	0.8%									
COMPOUND RATES OF GROWTH (%) 2000-2004	2.1%										
FORECAST											
2005	5288	9.7%	0.560	5723	18.8%	435	8.2%	4913	2.0%	-375	-7.1%
2006	5407	2.3%	0.557	5852	2.2%	445	8.2%	5024	2.3%	-383	-7.1%
2007	5481	1.4%	0.557	5935	1.4%	454	8.3%	5090	1.3%	-391	-7.1%
2008	5562	1.5%	0.557	6026	1.5%	464	8.3%	5163	1.4%	-399	-7.2%
2009	5667	1.9%	0.557	6140	1.9%	473	8.3%	5260	1.9%	-407	-7.2%
2010	5787	2.1%	0.557	6270	2.1%	483	8.3%	5372	2.1%	-415	-7.2%
2011	5919	2.3%	0.557	6411	2.3%	492	8.3%	5495	2.3%	-424	-7.2%
2012	6064	2.4%	0.557	6566	2.4%	502	8.3%	5632	2.5%	-432	-7.1%
2013	6209	2.4%	0.557	6720	2.4%	511	8.2%	5769	2.4%	-440	-7.1%
2014	6344	2.2%	0.559	6864	2.1%	520	8.2%	5896	2.2%	-448	-7.1%
COMPOUND RATES OF GROWTH (%) 2004-2014	2.8%			3.6%				2.0%			
NORMALIZED COMPOUND RATE OF GROWTH (%) 2004-2014	2.4%			3.2%				1.6%			

1. LOAD FACTOR = OUTPUT (MWH) / (8760 HOURS X SEASON PEAK (MW)).

Forecasted High Peaks are based on the weather that occurred on the 2001 peak day:
Peak Day Mean Daily Temperature = 88° F
Day Before Mean Daily Temperature = 86° F
Temperature Humidity Index = 87° F

Forecasted Low Peaks are based on the weather that occurred on the 2000 peak day:
Peak Day Mean Daily Temperature = 76° F
Day Before Mean Daily Temperature = 79° F
Temperature Humidity Index = 81° F

Temperature Humidity Index = 0.4 * (dry bulb temperature + wet bulb temperature) + 15°

CHAPTER III

CONSERVATION & LOAD MANAGEMENT

CHAPTER III

CONSERVATION & LOAD MANAGEMENT

A. Overview

The Conservation and Load Management Plan for 2005 ("Plan") was filed with the Connecticut Department of Public Utility Control ("DPUC") on November 22, 2004. The Plan was the result of close collaboration between CL&P, the Energy Conservation Management Board ("ECMB"), and the United Illuminating Company ("UI") and was submitted to the DPUC jointly with UI pursuant to DPUC Docket Nos. 02-01-22, 01-01-14, and 99-10-18. The Plan also received input from members of the public, industry groups and private enterprise and final approval by the ECMB was on November 18, 2004.

CL&P's proposed $58 million 2005 C&LM budget reflects approximately a fifty-four percent reduction over the last fully funded year in 2003. This reduction was due to actions taken by the Connecticut State Legislature. Public Act 03-2 ordered the transfer of one million dollars per month from the Conservation Fund to the Connecticut General Fund commencing in February 2003 and continuing through July 2005. Public Act 03-6 provided for the transfer of $194 million of conservation and renewable energy funds to the state's General Fund via a securitization mechanism and issuance of Rate Reduction Bonds ("RRB's"). Repayment of the RRB's is being made via an increase in the competitive transition assessment ("CTA") with a corresponding decrease in the legislated three mills-per-kWh C&LM surcharge stipulated in Public Act 98-28. The repayment period, and corresponding reduction in C&LM funding, will continue until 2011.

While Public Act 03-6 provided for C&LM program funding through the issuance of RRB's, its also imposed a spending cap on C&LM programs until RRB's were issued. As a result, CL&P collected more through its C&LM charge on customer's bills than it was legislatively allowed to spend, creating an unspent pool of C&LM funds which will offset the reduction in 2005 funding to some extent. The 2005 budget used for CL&P's demand forecast is $58 million.

CL&P has made projections of the statewide savings that will result from C&LM program activity for the period 2005 through 2009 based on these reduced funding levels. Beginning in the summer of 2002, CL&P took specific C&LM actions to support potential electricity shortages in southwestern Connecticut. Conservation activities in 2005 continue to focus on and support that critical area. However, these activities, and any additional efforts to support that critical area, are dependent upon continued stable funding. These activities target all fifty-four towns of southwestern Connecticut, especially the sixteen priority towns (Norwalk-Stamford sub-area) designated by ISO-NE.

B. Current Conservation & Load Management Programs

Table III-1, CL&P-Sponsored C&LM Peak Load MW Impacts, summarizes the projected impacts from program activity for CL&P over the forecast period, 2005-2014, based on the reduced funding described above in Section A. These peak load reductions reflect the direct impact of both historical and planned program activity over the five-year period beginning in 2005. Table III-2 provides a brief description of each C&LM program currently being implemented in the CL&P service territory. These programs utilize a complementary mix of lost opportunity, retrofit and market transformation implementation strategies. The projected impact of conservation programs and load management programs have been shown as separate line items since the average impact of conservation programs is greater than ten years, while load curtailment activities have a more immediate, short-term impact.

C. Ten-Year C&LM Forecast

Table III-2, CL&P C&LM Programs Annual Energy Savings and Peak Load Reduction by Customer Class, presents the potential annual energy savings and summer and winter peak load reductions forecasted for the C&LM programs implemented in the CL&P service territory for the program budgets described in Section A. Table III-2 reflects six years of projected program activity beginning in 2005. Past activity is included in the impact of prior activity shown in Tables III-1. The peak reductions include impacts of system losses, whereas the sales reduction numbers listed in these tables do not.

D. Forecast Sensitivity

The potential energy savings and peak load reductions projected in this forecast are sensitive to changes in a number of factors. The primary sensitivity is the funding instability described in Section A. The projections are also based on the continued implementation of a suite of programs similar in nature and focus to the Plan filed for 2003, the last fully funded year. Any legislative or regulatory changes in geographic and program focus will produce results which may vary from these projections. Additionally the achieved savings and load reductions are sensitive to changes in the electricity marketplace and customer attitudes which may result from the expiration of the Transitional Standard Offer.

CHAPTER IV

EXISTING AND PLANNED SUPPLY RESOURCES

CHAPTER IV

CL&P EXISTING AND PLANNED SUPPLY RESOURCES

A. Introduction

CL&P no longer owns any generation resources. However, CL&P continues to purchase generation under a number of purchase power agreements. CL&P also purchases generation under Rate 980 from a number of qualifying facilities whenever they choose to sell. In both cases, CL&P sells the energy into the wholesale market. The tables in this section have been simplified to reflect the fact that CL&P no longer owns generation or is serving load with its own resources as a result of electric industry restructuring in Connecticut. Per Connecticut General Statute section 16-244c, by July 1, 2007, CL&P and UI are to submit power contracts for at least 100 MW of class 1 renewable energy source projects to the DPUC for approval.

B. Explanation of Tables

The capacity tables in this chapter provide estimates of CL&P's supply resources during the 2005-2014 forecast period. All resources have winter and summer ratings in MW's to reflect the effects of varying ambient air and water temperatures on thermal unit ratings and river flow conditions on hydro unit ratings. Throughout this chapter, winter ratings are used in assessing CL&P's capacity situation relative to winter peak demand, and summer ratings are used in assessing its capacity situation relative to summer peak demand.

Table IV-1 lists existing supply resources in which CL&P has ownership or entitlement interests for Winter 2004/05 and Summer 2005.

Table IV-2 lists deactivation/retirement dates of CL&P generating units. CL&P has nothing to report.

Table IV-3 summarizes the ten-year capacity situation for CL&P during the winter and summer peak periods of 2005 through 2014. The table also shows CL&P's reserve expressed in MW's.

Table IV-4 provides details on the capacity from existing cogeneration and small power production facilities of 1 MW and greater located in Connecticut from which CL&P purchased power in 2004.

TABLE IV-1

GENERATING FACILITIES IN WHICH CL&P HAS OWNERSHIP OR ENTITLEMENT BY CATEGORY AS OF JANUARY 1, 2005

This table lists supply resources in which CL&P has ownership or entitlement interests in, arranged in Base Load, Intermediate, Peaking, Pumped Storage, Hydro, and Purchases categories. Base load units are typically operated around the clock, intermediate units are those used to supply additional load required over a substantial part of the day, and peaking units supply power usually during the hours of highest demand. On occasion, some of the more efficient intermediate units operate as base load units, while others may be called upon to operate as peaking capacity. Accordingly, these categories are intended to be generally descriptive rather than definitive, and reflect past operating patterns. Pumped storage units use low-cost generation during off-peak periods to store water for the production of electricity during high-cost peak periods. Hydroelectric units may operate as base load, intermediate, or peaking capacity depending on the availability of water, which tends to vary seasonally. Shown is CL&P's entitlement in each unit along with location by town and state.

TABLE IV-1

GENERATING FACILITIES IN WHICH CL&P
HAS OWNERSHIP OR ENTITLEMENT
BY CATEGORY AS OF JANUARY 1, 2005

	WINTER RATING (MW) 2004/05	SUMMER RATING (MW) 2005	YEAR INSTALLED	LOCATION	% ENTITLEMENT CL&P
Base					
Vermont Yankee	50.26	48.07	1972	Vernon, VT	9.50
Nuclear Subtotal	50.26	48.07			
Intermediate	0.00	0.00			
Peaking	0.00	0.00			
Pumped Storage	0.00	0.00			
Hydro	0.00	0.00			
Purchases					
System	45.00	45.00			
Non-Utility	348.29	336.24			
Purchase Total	393.29	381.24			
TOTAL GENERATION	443.55	429.31			

TABLE IV-2
CL&P
ASSUMED DEACTIVATIONS AND RETIREMENTS OF GENERATING UNITS

None.

TABLE IV-3

CL&P 2005-2014 FORECAST OF GENERATING CAPACITY AT THE TIME OF WINTER AND SUMMER PEAK

Table IV-3 summarizes the ten-year capacity situation for CL&P during the winter and summer peak periods of 2005 through 2014 including the impact of the Restructuring Act, as appropriate. The table also shows CL&P's reserve margin expressed in MW's.

SUPPLY BEFORE SALES OR EXCHANGES is made up of supply resources in which CL&P has ownership or entitlement interest as detailed in Table IV-1, including purchases.

NET EFFECT OF CAPACITY EXCHANGES is the cumulative purchase or sale resulting from capacity exchange transactions.

CAPACITY SALES are unit or system power sales that result in a transfer of capacity from CL&P to the purchaser.

NET GENERATION AVAILABLE is the sum of the foregoing categories.

RESERVE is the difference between Net Generation Available and the Estimated Peak Load. Since CL&P no longer serves load with its own resources, reserve equals net generation available.

TABLE IV-3
(PAGE 1 OF 2)

THE CONNECTICUT LIGHT & POWER COMPANY
2005-2014 FORECAST OF CAPACITY (MW) AT THE TIME OF WINTER AND SUMMER PEAK
(AS OF JANUARY 1, 2005)

	WINTER 2004/05	SUMMER 2005	WINTER 2005/06	SUMMER 2006	WINTER 2006/07	SUMMER 2007	WINTER 2007/08	SUMMER 2008	WINTER 2008/09	SUMMER 2009
SUPPLY BEFORE SALES OR EXCHANGES	443.55	429.31	443.44	429.21	443.44	429.21	443.44	429.20	398.44	384.20
NET EFFECT OF CAPACITY EXCHANGES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPACITY SALES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET GENERATION AVAILABLE	443.55	429.31	443.44	429.21	443.44	429.21	443.44	429.20	398.44	384.20
RESERVE	443.55	429.31	443.44	429.21	443.44	429.21	443.44	429.20	398.44	384.20

TABLE IV-3
(PAGE 2 OF 2)

THE CONNECTICUT LIGHT & POWER COMPANY
2005-2014 FORECAST OF CAPACITY (MW) AT THE TIME OF WINTER AND SUMMER PEAK
(AS OF JANUARY 1, 2005)

	WINTER 2009/10	SUMMER 2010	WINTER 2010/11	SUMMER 2011	WINTER 2011/12	SUMMER 2012	WINTER 2012/13	SUMMER 2013	WINTER 2013/14	SUMMER 2014
SUPPLY BEFORE SALES OR EXCHANGES	391.54	339.85	352.54	339.85	352.54	287.14	242.60	239.07	242.60	239.07
NET EFFECT OF CAPACITY EXCHANGES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPACITY SALES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET GENERATION AVAILABLE	391.54	339.85	352.54	339.85	352.54	287.14	242.60	239.07	242.60	239.07
RESERVE	391.54	339.85	352.54	339.85	352.54	287.14	242.60	239.07	242.60	239.07

TABLE IV-4

EXISTING CUSTOMER OWNED FACILITIES 1 MW AND ABOVE
PROVIDING GENERATION TO THE NORTHEAST UTILITIES SYSTEM

EXISTING & PROVIDED GENERATION TO CL&P DURING 2004

Project Name	Location	(1) Facility Type	Fuel Source	By-Product of Fuel Consumption	Estimated Capacity kW	Max Claimed Capability Winter	Max Claimed Capability Summer
FACILITIES UNDER LONG TERM CONTRACT (2)							
AES	Montville, CT	COGEN	Coal	Steam	181,000	182,150	181,000
C.H. Dexter	Windsor Locks, CT	COGEN	Gas	Steam	39,000	39,000	38,000
Derby Dam	Shelton, CT	SPP	Hydro	-	6,900	7,050	7,050
Goodwin Dam	Hartland, CT	SPP	Hydro	-	3,294	2,064	2,064
Colebrook	Colebrook, CT	SPP	Hydro	-	3,000	1,373	1,373
Quinebaug	Danielson, CT	SPP	Hydro	-	2,161	2,810	980
Kinneytown B	Seymour, CT	SPP	Hydro	-	1,500	654	654
Mid-CT CRRA(So. Meadow 5/6)	Hartford, CT	SPP	Refuse	-	64,100	59,675	52,709
Preston (SCRRRA)	Preston, CT	SPP	Refuse	-	13,850	16,946	16,011
Bristol RRF	Bristol, CT	SPP	Refuse	-	13,200	12,736	13,200
Lisbon	Lisbon, CT	SPP	Refuse	-	13,500	13,036	12,961
Wallingford RRF	Wallingford, CT	SPP	Refuse	-	7,100	6,900	6,350
Hartford Landfill	Hartford, CT	SPP	Methane	-	2,445	2,564	2,564
					351,050	**346,958**	**334,916**
FACILITIES NOT UNDER LONG TERM CONTRACT (3)							
Pratt & Whitney	E. Hartford, CT	COGEN	Gas	Steam	23,800	N/A	N/A
Rainbow (Farmington River Power)	Windsor, CT	SPP	Hydro	-	8,200	N/A	N/A
Ten Co./The Energy Network	Hartford,CT	COGEN	Gas	-	4,500	N/A	N/A
Wyre Wynd	Jewett City, CT	SPP	Hydro	-	1,800	N/A	N/A
					36,500	**0**	**0**
				TOTAL EXISTING	**387,550**	**346,958**	**334,916**

(1) "SPP" Denotes a Small Power Producer, "COGEN" Denotes a Cogenerator.
(2) Estimated Capacity Represents Contracted Capacity.
(3) Estimated Capacity Represents Estimated Installed Capacity.

CHAPTER V

EXISTING AND PLANNED TRANSMISSION FACILITIES

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EXISTING AND PLANNED TRANSMISSION FACILITIES

A. Introduction

This chapter contains CL&P's plans to enhance the transmission system in Connecticut and a discussion of the complexities associated with transmission planning in a restructured electric utility industry with a competitive generation marketplace. The hierarchy of national and regional transmission reliability standards, the regional transmission planning process led by ISO-NE, and the Connecticut transmission system that is currently under reliability evaluation in a number of locations are topics addressed in this chapter. Also, emerging issues that could affect the expansion and effectiveness of the CL&P transmission system are discussed. Finally, there are four tables which list planned and proposed additions and upgrades to CL&P's transmission system through 2014.

Since CL&P's 2004 FLR report was filed, significant developments have occurred that have a direct impact on transmission services in Connecticut. These developments include the North American Electric Reliability Council's ("NERC") approval of new reliability standards and institution of compliance enforcement and certification programs, ISO-NE's conversion to an RTO, continued ISO-NE changes to the regional system planning process, and near-term changes to the competitive generation marketplace that could have a substantial impact on electric service in Connecticut. The following sections provide additional information and insight on these developments.

B. Transmission Planning in a Competitive Generation Marketplace

Prior to the restructuring initiatives in the late 1990's, electric utilities coordinated the planning and operation of generation, transmission and distribution facilities in a vertically integrated utility environment. Each utility performed all the functions to serve the generation and transmission needs of their customers within their defined service territory. These regulated monopolies not only collected and developed the information (e.g., electricity trends and forecasts), but managed the resources (i.e., generation, transmission and distribution facilities) to mitigate or minimize transmission constraints.

Centralized decision-making by electric utility companies no longer determines electricity production. Instead, competitive market forces and new participants control electricity production. This includes the amount or size of generating units, when they'll be installed, and where they will be located. The changed structure between generation production and transmission operation has contributed to electric power system congestion.

Restructuring resulted in transmission systems being regulated by the Federal Energy Regulatory Commission ("FERC"), distribution systems by state regulatory agencies and generation production operating in a competitive marketplace. Restructuring in New England brought about a shift in generation ownership from the local utility to regional energy providers. The introduction of competition into one segment of a previously regulated monopoly industry altered the focus of transmission system planning. Local transmission systems built to serve customer load from utility-owned generating units within a more restricted geographic area may now be stressed to serve the same customer load from remote merchant generating sites. In these instances the transmission solutions are totally different.

The electric utility industry continues to undergo significant change; transmission planning was profoundly impacted by the recent restructuring developments in New England. These developments include a large number of new merchant generators in New England, the uncertainty of stalled merchant generator projects, bankruptcy filings of large generating companies, the consolidation of yet other generating companies, the deactivation or retirement of aging generators, and the potential for early retirement of multiple generating units for environmental or economic reasons. Specific generators have petitioned ISO-NE for reliability-must-run ("RMR") agreements while other generators have been temporarily installed on the system under ISO-NE sponsored RFP's to help ensure the reliability of the power system primarily during peak-load periods. These developments have added complexity to transmission planning which is dynamic. Transmission planning must develop or come forth with sufficiently flexible solutions to meet the increased demands to transfer power from remote resources to load centers and incorporate numerous variables that could change or influence the future energy needs of a particular area.

In 1997, NERC stated the following:

> *The new competitive electricity environment is fostering an increased demand for transmission service. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and the capability of these systems to reliably support a wide variety of transfers. The future challenge will*

be to plan and operate transmission systems that provide the requested electric power transfers while maintaining overall system reliability. All electric utilities, transmission providers, electricity suppliers, purchasers, marketers, brokers, and society at large benefit from having reliable interconnected bulk electric systems. To ensure that these benefits continue, all industry participants must recognize the importance of planning these systems in a manner that promotes reliability.[1]

Even with this NERC pronouncement as a backdrop, the actual planning and construction of transmission has become significantly more complex, controversial and time consuming.

C. Reliability Standards

Nationally recognized transmission reliability standards were developed to meet the regulatory requirement to provide an electric power supply system with an acceptable level of service reliability in a cost-effective manner. The CL&P facilities that are part of the interconnected bulk power system are designed and operated in accordance with the NERC Planning Standards, Northeast Power Coordinating Council ("NPCC") Basic Criteria for Design and Operation of Interconnected Power Systems, and the Reliability Standards for the New England Power Pool ("NEPOOL"). These transmission reliability standards apply to CL&P 345-kV transmission lines, 345/115-kV and 115/69-kV autotransformers, and 115- and 69-kV transmission lines. The goal of transmission planning at CL&P is to ensure that a reliable and economic bulk power supply system exists within the framework of the criteria established by NERC, NPCC and NEPOOL.

NERC's mission is to ensure that the bulk electric system in North America is reliable, sufficiently robust, meets national adequacy standards, and secure. Since its formation in 1968, NERC has operated successfully as a self-regulated organization, relying on reciprocity, peer pressure, and the mutual self-interest of all those involved in the electric system. Even with this voluntary approach, NERC has been able to develop the North American bulk electric system into the most reliable electric system in the world. NERC membership comprises ten regional reliability councils that account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

In 1995, NERC described the planning process as follows:

Planning is the process by which changes and additions to the bulk electric system are determined. The interconnected electric systems must be able to accommodate a wide range of system conditions and contingencies - continuously varying customer demands,

[1] Planning Standards, North American Electric Reliability Council, September 1997

differing amounts and patterns of electrical generation as determined by availability and costs, and various planned and unplanned outages of the transmission facilities. This process strives to develop systems that will provide desired capability and performance in a cost-effective manner, while reliably supplying the electrical demands of customers and satisfying the business needs of electric system owners.[2]

Transmission reliability standards seek to ensure that a consistent relationship exists between the reliability of the CL&P facilities that make up the interconnected bulk power supply system and the reliability of CL&P's local area supply systems. This relationship is achieved by specifying planning contingencies for the design of the local area supply systems which are similar to those of the interconnected bulk power system. These standards test system reliability by means of a deterministic approach, producing a systematic, dynamic and static evaluation of the electrical system based on a predefined set of contingencies and forecasted load levels. Contingencies are simulated on computer models developed to represent actual or future system conditions. Behaviors of the system when subjected to these contingencies must fall within prescribed limits of machine stability, equipment current-carrying capabilities, and permissible ranges of voltage and frequency.

Since the August 14, 2003 blackout affecting the northeastern United States and part of Canada, NERC and FERC have instituted a process of reviewing and further clarifying the reliability standards and compliance requirements for the bulk electric system.

Transmission reliability standards recognize the evolving competitive generation marketplace in New England. Maintaining the reliability of the power system is essential, both to ensure a robust competitive marketplace for electricity, satisfy customer demands and expectations with regard to service reliability, and to protect the health, welfare and safety of the public.

D. Regional Transmission Planning Functions

On February 1, 2005, ISO-NE made the transition to an RTO, assuming broader authority over the day-to-day operation of the region's transmission system. ISO-NE now possesses a greater level of independence to effectively manage the region's bulk electric power system and competitive wholesale electricity markets.

As an RTO, ISO-NE will continue to perform all of its current responsibilities and will also exercise day-to-day operational control of the transmission system. ISO-NE will be the single point-of-control to effectively maintain reliability and preserve the integrity of the bulk

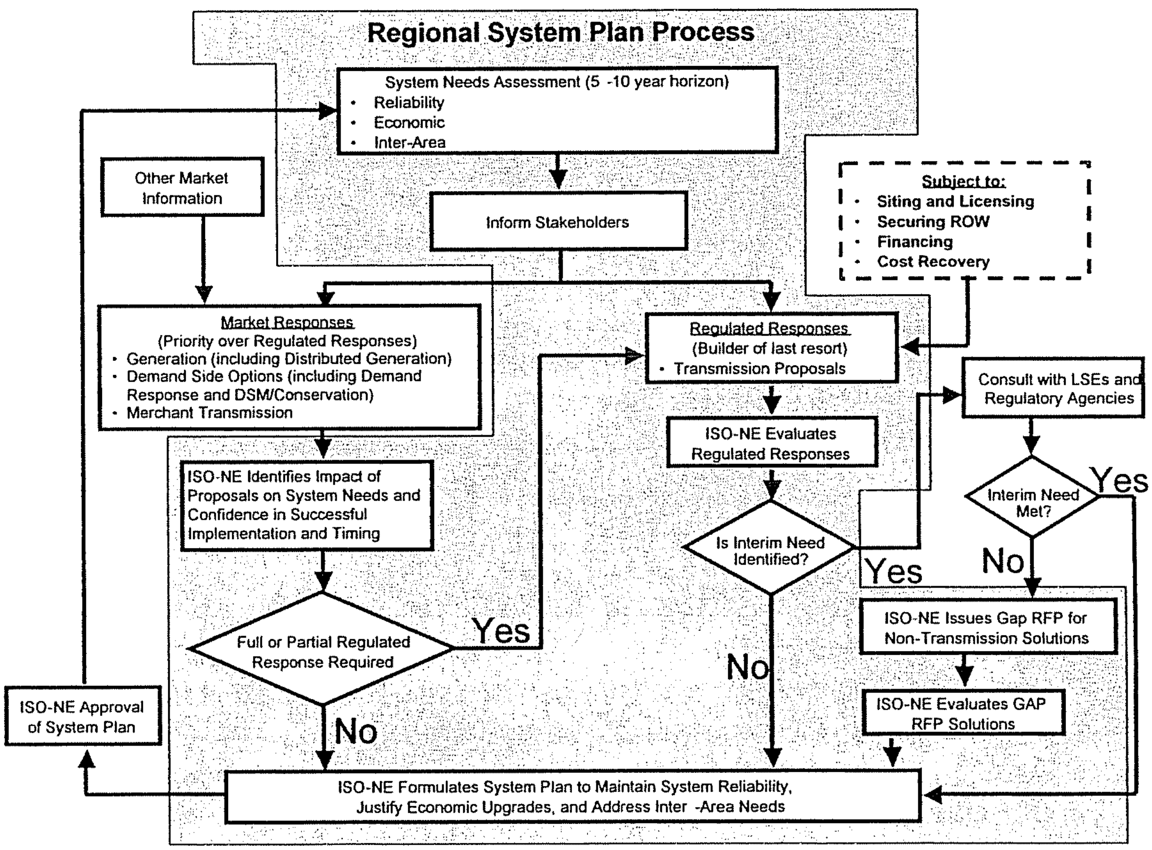
[2] Planning Of The Bulk Electric Systems, North American Electric Reliability Council, Coordinated Planning Task Force of the Engineering Committee, May 1995

power system on a daily basis and in emergency situations. ISO-NE will also enhance the regional system planning process that identifies New England's electricity needs and promotes infrastructure improvements where they are most needed.

ISO-NE

In 2001, FERC required NEPOOL to cede exclusive responsibility for the transmission planning process to ISO-NE. Diagram A depicts the Regional System Plan ("RSP") process flow that was developed by ISO-NE. The diagram depicts a process whereby ISO-NE solicits, from many stakeholders, alternatives that seek to solve New England's reliability problems in a system needs assessment phase. ISO-NE identifies and proposes transmission projects that address system reliability and economic efficiency issues which are not resolved by market responses. It is recognized that market responses that materialize later may alter the scope of any plans ISO-NE develops.

Diagram A



Note: PAC – Planning Advisory Committee
LSE – Load Serving Entity

Regional System Plan

ISO-NE is responsible for developing and maintaining a process that creates a transmission plan on a coordinated regional basis. The annual RSP approved by the ISO-NE's Board of Directors includes the necessary facilities to ensure the reliability of the NEPOOL transmission system, taking into account load growth and known resource changes. Within this plan, transmission upgrades for reliability purposes are those improvements found necessary to provide acceptable stability response, short circuit capability and acceptable system voltage and frequency levels. Such upgrades may also include facilities required to provide adequate thermal capability and local voltage control that cannot otherwise be achieved by a reasonable re-dispatch of generation. In evaluating such needs, the criteria, rules, standards, guides and policies of NERC, NPCC, NEPOOL, ISO-NE, and transmission owners are used.

The RSP shall conform to Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of NERC and NPCC, applicable and publicly available local reliability criteria, and the NEPOOL system rules. It must also account for economic and environmental considerations. The plan recommendations shall be based on the results of comprehensive transmission expansion and enhancement studies conducted at least once every three years. The scope of the plan shall account for, at a minimum, the ensuing five-year load and capacity forecasts, proposed generation additions and retirements, proposed merchant transmission facility additions, and the requirements for system restoration services. The plan shall avoid unnecessary duplication of facilities and the imposition of unreasonable costs upon any transmission owner, transmission customer or user of a transmission facility, taking into account the legal and contractual rights and obligations of the transmission owners and the transmission-related legal and contractual rights and obligations of any other entity; and provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans.

Planning Advisory Committee

The framework for developing the RSP includes a Planning Advisory Committee ("PAC") comprised of New England transmission owners and other interested stakeholders including generator owners, marketers, load serving entities, government representatives, and state agencies. The PAC is responsible for providing input to ISO-NE on the plan's development. The PAC may also conduct planning studies and provide comments on policy issues, study objectives, study scopes, and alternative solutions for ISO-NE consideration. The transmission owners are responsible for providing the data, information and analytical support necessary to perform studies and to address identified engineering and technical issues, solutions and alternatives in connection with the plan.

NEPOOL Recommendation Process

Transmission owners are one of the market sectors that coordinate with ISO-NE to develop periodic regional transmission plans. Once a transmission plan is finalized, the transmission owner must apply to ISO-NE for approval to interconnect modified or new transmission facilities under Section I.3.9 of the ISO-NE Transmission, Markets and Services Tariff. This review and approval process was first established in the 1970s and continues now under the RTO. The Section I.3.9 (formerly known as the 18.4 process under the prior NEPOOL Agreement) is an adverse impact test that is performed under peer review by ISO-NE and NEPOOL participants. Approval to interconnect modified or new proposed transmission plans will only be granted if the facility does not adversely impact transmission systems. If studies indicate that adverse results could or may occur, mitigation measures must be incorporated.

The approval process is initiated with a review of the I.3.9 studies by the NEPOOL technical task forces. When the task forces are satisfied that the studies demonstrate the proposed projects will have no adverse impact on the system, the formal I.3.9 application is submitted to ISO-NE, then to the NEPOOL Reliability Committee which reviews and recommends approval of the I.3.9 application to ISO-NE. Once the I.3.9 application is recommended for approval by NEPOOL, ISO-NE's Board of Directors makes the final decision and incorporates the approved projects in the regional system plan.

New England Transmission Cost Allocation

On December 20, 2002, FERC issued an order in the New England standard market design ("SMD") proceeding that provided guidance for a New England transmission cost allocation methodology. On July 31, 2003, after an extensive stakeholder process, NEPOOL and ISO-NE filed comprehensive Transmission Cost Allocation ("TCA") Amendments to the NEPOOL Open Access Transmission Service Tariff ("NEPOOL Tariff") with FERC. On December 18, 2003, FERC accepted the New England TCA Amendments and modified the NEPOOL Tariff. The cornerstone of the TCA Amendments is the establishment of regional cost support, and participant funding which depends on the type of upgrade to the transmission system. The TCA Amendments also changed the decision maker authority on the classification of facilities in each category and the determination of localized costs from NEPOOL to ISO-NE.

Regional cost support is the inclusion of transmission costs in the regional network service rates which are paid by all New England transmission customers under the ISO-NE tariff. The expectation is that transmission facilities in the regional rates will continue to provide benefits throughout New England. Two types of transmission facilities qualify for regional cost support, Reliability Upgrades and Economic Upgrades. Together, these facilities are classified as Regional Benefit Upgrades.

Reliability Upgrade projects are eligible for regional cost support if the ISO-NE determines, through the PAC process, that the upgrade is needed for reliability. These upgrades may also produce net economic benefits for the region. Reliability Upgrade projects are added to the regional transmission expansion plan after markets are first given an opportunity to provide participant-funded solutions to system needs. ISO-NE identifies Reliability Upgrades through transmission system assessments which are conducted in accordance with the NERC, NPCC and NEPOOL planning standards. Through this assessment process, ISO-NE identifies those transmission upgrades that are necessary to ensure acceptable ranges of system stability, and short-circuit, voltage and thermal capabilities for New England.

Economic Upgrades that are eligible for regional cost recovery are those transmission upgrades that provide net economic benefits to the region, as determined by ISO-NE.

The costs of participant-funded solutions are not regionalized and included in regional network service rates. This methodology is intended to assure that entities that caused the costs to be incurred, and will likely receive the benefits from the facility, pay for it. These types of facilities include: Generator Interconnection-Related Upgrades, Elective Transmission Upgrades, Local Benefit Upgrades, Merchant Transmission Facilities and Localized Costs of Regional Benefit Upgrades.

The costs of Generator Interconnection-Related Upgrades are paid by the generator. These upgraded facilities may include both generator leads and upgrades to the regional and/or local transmission systems.

The costs of Elective Transmission Upgrades are appropriately allocated to those entities that have elected to construct a transmission facility for their own benefit.

The costs of Local Benefit Upgrades are paid by customers under local network services for facilities that have been determined by ISO-NE not to provide regional benefits.

The costs of Merchant Transmission Facilities are paid under bilateral contracts between the contracted parties. These are facilities that have been constructed for specific purposes outside of the PAC process.

Localized Costs are the dedicated costs for facilities that are associated with Regional Benefit Upgrades, but which will be paid for by a state or local area. ISO-NE has determined that Localized Costs should not be supported on a regional basis. ISO-NE, in its review of project costs, will determine whether any incremental costs resulting from any local, state regulatory and/or legislative requirements will be identified as Localized Costs.

Transmission Planning Philosophy

New investments in transmission facilities will ensure the continuance of a reliable and dependable electric power system to support electric service requests, public safety and the expansion of the Connecticut economy. It is transmission planning's philosophy to have a known and measurable plan to reliably meet future peak load demands.

Proposed transmission additions generally serve at least one of the following purposes:

1) To reliably serve customers' peak-load demands.
2) To maintain system reliability under varying generator dispatch scenarios.
3) To provide transmission capability to transfer power on a regional basis.
4) To provide transmission capability to efficiently deliver output, locally or regionally, from new generation which interconnects to the transmission system.
5) To resolve system reliability and safety concerns of high short-circuit currents.

New transmission facilities are justified by a determination of a need for system reinforcements to maintain reliability performance in accordance with design standards. They are supported with a quantitative comparison of the future reliability benefits and the cost of the facility versus other transmission alternatives. The integration of the CL&P transmission system with the regional transmission system allows for contingent support to come from different areas of CL&P and from neighboring utilities. CL&P strives to balance the need for additional system capability with the economics of the new facilities targeted to customers' load growth projections.

E. CL&P's Transmission System

CL&P's transmission system is part of the interconnected New England transmission network. Transmission lines across the New England region and outside of the region are interconnected to form a transmission network, sometimes called a "grid" or "system." The transmission grid serves multiple purposes, all of which work together to enhance reliability. CL&P and other electric utilities design the transmission grid to satisfy federal, regional and company criteria. The desired result is reliable electric service. ISO-NE operates the system as one integrated network in order to provide reliable and economic energy throughout the region.

At the end of 2004, CL&P's in-service transmission circuits are comprised of 392.3 circuit miles of 345-kV (all of which are overhead lines), 5.8 circuit miles of 138-kV (all of which are underwater cables), 1173.9 circuit miles of 115-kV (which includes 40.3 miles of underground cables), and 99.5 circuit miles of 69-kV lines (which includes 2.8 miles of underground cables).

The CL&P 345-kV system transmits power from large central stations such as Millstone, Lake Road, and Middletown 4 via four 345-kV transmission tie lines with neighboring utilities. There is one tie with National Grid, one with UI, one with WMECO, and one with Consolidated Edison ("Con Ed") in New York.

The electrical network also contains forty-one transmission tie points to neighboring utilities, all rated between 69-kV and 138-kV. There is one tie with National Grid, one with Long Island Power Authority ("LIPA"), one with Central Hudson ("CH"), thirteen with Connecticut Municipal Electric Energy Cooperative, Inc. ("CMEEC"), twenty with UI, and five with WMECO.

The CL&P electric transmission network, with its tie lines to neighboring utilities, provides the paths that allow power to move freely over the New England electrical network. This means power can flow in any direction, depending on generation dispatch and load patterns and the real time configuration of the transmission system. Subject to certain system and equipment limits, this electrical network enables the CL&P system to rely on import capabilities and to also contribute to serving other New England load. The transmission tie lines provide both CL&P and neighboring systems access to economic generation and increased reliability during various generation dispatch scenarios and following system emergencies, once again, subject to certain system and equipment limits.

There are seven major CL&P bulk power substations. The Montville, Card, Manchester, Southington, Frost Bridge, North Bloomfield and Plumtree substations interconnect to 345-kV lines and transform voltage from 345 kV to 115 kV. These transformation systems enable bulk power from the large central stations and transmission tie lines to be delivered from the 345-kV system to the CL&P 115-kV system.

The 115-kV system loops through high load density areas in central and southwest Connecticut and connect the load centers to the eastern part of the state. For example the major 115-kV loops through western and SWCT tie to the 345-kV interconnections at Southington, Frost Bridge and Plumtree. Overall this system transmits power from central stations, transmission tie lines and bulk power substations to distribution step-down substations which supply local area load.

F. Background for Transmission System Evaluations

Demand Forecasts

ISO-NE in conjunction with CL&P develops annual forecasts of peak loads for each New England state. The forecast used for transmission planning studies is a 90/10 value. The actual peak load has a 10% chance of exceeding the 90/10 forecasted load level and a 90% chance of falling short of the 90/10 forecasted load level. New England uses this 90/10 demand forecast philosophy to develop its transmission plans. This planning approach provides more certainty of providing reliable service even under the reasonably severe weather conditions.

Electrical Interfaces

Redistribution of power flows result when generators or transmission lines are intentionally or unintentionally removed from service. Because power flows instantaneously seek alternate paths under these scheduled and unscheduled conditions, the results can cause adverse impacts on local or remote systems. One method for operators to evaluate transmission system performance and to protect the system from a wide-area interruption is to establish electrical interfaces for monitoring purposes. These interfaces are defined as sets of transmission facilities that can be used to reliably transfer power, within defined limits, from one area to another. The capability of an electrical interface is estimated by computer simulations that find the maximum allowable power transfer which, for pre-defined contingencies, does not violate prescribed limits of machine stability, equipment current carrying capabilities and permissible ranges of voltage and frequency.

The transfer limit of an interface cannot be determined solely by the summation of line capabilities. Due to the proximity of load pockets and generating resources, portions of Connecticut's transmission system are included in multiple regional electrical interfaces. These interfaces are the Norwalk – Stamford, Southwest Connecticut, Connecticut import, New England East – West and New York – New England.

Short-Circuit Currents

An interconnected transmission system of lines and substations enables reliable transfer of large blocks of power. One design challenge of a tightly knit and interconnected transmission network that is operated at a single voltage is reduced impedance between the generators and earth during system fault events. A fault occurs when one or more phases of a three-phase transmission system are accidentally connected together or to earth.

During a fault, all generators on the system deliver power to the fault. The amount of current flowing to the fault is dictated by the system impedance between the generators on line and the fault, including any resistance at the fault. The consequence is higher short-circuit currents on the network.

Short-circuit currents can reach forty times the normal current flow levels. These high short-circuit currents cause large mechanical forces and subject conductors, overhead line shield wires and equipment to high temperatures and additional stress. Transmission line and substation equipment is designed to withstand these short-duration forces and heating. The interrupting rating of a circuit breaker is the amount of short-circuit current it can interrupt safely without harm to personnel, other surrounding equipment or the device itself. Other line and substation equipment must have the ability to carry these currents without damage or hazards to workers. Switches, grounding clamps and bus, etc. must also be able to withstand the mechanical forces and heating brought about by the short-circuit currents. Buried substation ground grids, when subjected to the maximum short-circuit currents must be designed to limit step and touch potentials to safe levels to protect workers. System operators also have an added concern for worker safety when short-circuit currents exceed 43,000 amps, because of the limitations of the temporary grounding equipment line workers depend on for their personal protection.

Short-circuit currents on a transmission system are aggravated by the addition of new larger generating units. One method to reduce short-circuit currents is to increase the system impedance between the generators and earth. However, the building of additional transmission lines at the same voltage level to which generators connect reduces the system impedance. Upgrading existing transmission lines with higher capacity lines also reduces system impedance. When the system impedance between generators and fault locations is reduced, short-circuit currents are increased. The use of a second and higher voltage for new lines results in a dual-voltage system. These systems enable the larger generators to be connected to the higher voltage network, with autotransformers providing additional impedance between generators and faults on either voltage system. Dual-voltage transmission systems enable flexible operation, easier integration and safer conditions for generation and transmission facilities.

G. <u>Transmission System Evaluations</u>

For the purpose of assessing the reliability of the CL&P transmission system, the system has been divided into several areas. A description of the regions and a summary of the future transmission needs in each area are discussed below. See Figure 1 for a map of the various areas and tables V-2 through V-5 which list the various proposed transmission facilities for the following geographic areas.

Southwest Connecticut Area: The largest and most critical area on the CL&P transmission system is the 54-town SWCT area including all of the UI service territory. This area, which is essentially west of Interstate 91 and south of Interstate 84 accounts for approximately half of the peak load in the state of Connecticut and is one of the fastest growing and economically vital areas of the state. This area is primarily served by 115-kV transmission lines which have essentially reached the limit of their ability to reliably and economically support the area's current and projected load. Contained within this area is the **Norwalk – Stamford Sub-Area** which has historically been reliant on generation within the area to reliably serve the load. With the change to a market-based system and the aging nature of the local generating plants, it is no longer feasible to rely on generation to meet the longer term reliability needs of the area.

A study of SWCT including Norwalk – Stamford was completed in 2002 by ISO-NE, CL&P, and UI. The study group proposed a comprehensive long range solution to the multitude of problems identified in this area. The plan identified the need to construct a 345-kV loop to integrate the SWCT area into the New England 345-kV bulk power electric transmission grid.

The first phase of the reinforcement plan is to construct a 345-kV line from Plumtree Substation, in Bethel, to the Norwalk Substation, in Norwalk. The plan includes reconstruction for portions of the existing 115-kV lines between these two substations. In Docket No. 217, the CSC approved a combination of overhead and underground line construction for portions of the existing 115-kV line and for the entire new 345-kV line between Bethel and Norwalk. These line configurations include use of approximately 10.0 miles of 115-kV extruded insulation cable ("XLPE"), and 2.1 miles of 345-kV XLPE cable. A significant 9.7-mile length of high-pressure fluid-filled 345-kV cables ("HPFF"), plus approximately 8.6 miles of overhead 345-kV line complete the 20.4-mile circuit.

CL&P and UI currently have before the CSC an application for a proposed 345-kV line from the Middletown area to Norwalk Substation. The proposed project consists of a new 345-kV switching station to be constructed at Beseck Junction, in Wallingford. The existing 345-kV Millstone-Southington line will be reconfigured and the line section from Millstone is planned to be extended west from Oxbow Junction to Beseck. The Southington leg of this line will be extended east from Chestnut Junction to the 345-kV Scovill Rock Switching Station. In addition, the existing 345-kV Southington-Haddam Neck line is planned to loop south from Black Pond Junction to Beseck. From the new Beseck Switching Station the project includes approximately 33.4 miles of overhead 345-kV transmission line to a new East Devon Substation, in Milford. Between East Devon and a new Singer Substation in

Bridgeport, two 8.1-mile circuits of 345-kV XLPE cable are proposed. The final leg of the 345-kV loop is completed between Singer Substation and the Norwalk Substation with the proposed construction of two 15.5-mile circuits of 345-kV XLPE cable. The proposed project also includes 115-kV line upgrades and the modification of the interconnection of Milford Power and Bridgeport Energy to the transmission system. These new transmission facilities are the subject of CSC Docket No. 272.

During the extended SWCT study period extensive testing was conducted to integrate long lengths of 345-kV underground cables in SWCT's weak overhead transmission system. It was determined that SWCT was subject to lower resonances in the range of the 2^{nd} and 3^{rd} harmonic. Operating an electric power system at these frequencies could pose a reliability and safety problem for the network. CL&P determined that a lower frequency resonance was consistently troublesome in the vicinity of the Stony Hill and Bates Rock substations. Industry consultants that were involved in Docket No. 272 had advised CL&P to consider the use of C-type filters to integrate an additional unprecedented amount of 345-kV XLPE cable in the SWCT area. Although C-type filters are not recommended for the proposed 345-kV transmission line from Middletown to Norwalk they could have a positive impact on the local temporary overvoltage problems in the Stony Hill and Bates Rock areas. CL&P plans to evaluate the use of C-type filters in these local areas and elsewhere on the CL&P system where lower frequency natural resonances are present.

CL&P has filed an application for two proposed 115-kV transmission lines between the Norwalk Substation, in Norwalk, and the Glenbrook Substation, in Stamford. These new transmission lines are the subject of CSC Docket No. 292.

CL&P has also filed petitions seeking declaratory rulings for the proposed rebuild of the 115-kV transmission lines between Triangle Substation, in Danbury, and the Plumtree Substation, in Bethel. These transmission line and substation upgrades are the subject of CSC Petitions No. 700 and 702.

The replacement of the existing 138-kV submarine cable from Norwalk Harbor to Northport, Long Island was approved in CSC Docket No. 224. On June 24, 2004, NU entered into a Settlement Agreement ("SA") with the LIPA, DPUC, Department of Environmental Protection, and Cross-Sound Cable Company ("CSCC") to resolve pending FERC filings and to allow the permitting process to continue.

Along with implementing system-upgrade solutions to help solve the transmission constraints in SWCT, CL&P has been aggressively implementing C&LM solutions for its customers. Since 2002, CL&P has offered uniquely tailored C&LM programs for residential, commercial, industrial, and municipal customers in SWCT towns. These innovative programs promote energy efficiency measures that not only save energy, but also reduce system peak demand. While these efforts cannot of themselves solve congestion in SWCT, CL&P believes its C&LM programs are part of a total solution and has asked the DPUC for approval to continue offering them in 2005.

Manchester – Barbour Hill Area: The area including part of Manchester, the towns located north and east of Manchester and east of the Connecticut River in north central Connecticut, and the towns of Suffield and Windsor Locks west of the river and including Bradley International Airport, is primarily supplied by two radial 115-kV transmission lines from Manchester substation. The rapid growth along the Interstate 91 and Interstate 84 corridors and especially in Manchester and South Windsor adjacent to the Buckland Hills Mall has established the need to upgrade the transmission system. The reliability needs of the area can initially be addressed by the installation of a 345/115-kV autotransformer at the Barbour Hill Substation in South Windsor. CL&P is also considering upgrades to the existing 115-kV transmission lines from the Manchester Substation to the Barbour Hill Substation.

Northwest Connecticut Area: The northwest portion of the state is presently supplied by four 115-kV transmission lines. In the future, it may be necessary to convert the existing 69-kV transmission system between Torrington and Falls Village to 115-kV (lines were pre-built in the1970's for 115-kV operating capability under Petition No. 26) or add a second 115/69-kV autotransformer at Torrington Terminal Substation. In addition planning studies are being conducted to evaluate the benefits of a new transmission line into the area. One alternative would be a 115-kV transmission line between the Frost Bridge Substation, in Watertown and Walnut Junction, in Thomaston.

Eastern Connecticut Area: The eastern Connecticut area extends from the Rhode Island border in a westerly direction for about twenty miles and northerly from Long Island Sound to Massachusetts. The area is served by both CL&P and CMEEC, and is planned to the same reliability standards regardless of which entity is serving the load. In 2005, the University of Connecticut's cogeneration facility will be connected to the 69-kV transmission system in Mansfield. The eastern Connecticut area has experienced load growth along the Interstate 95 corridor and from the Foxwoods and Mohegan Sun casinos. It is also important to ensure that a high level of reliable electric service is maintained at local military installations. The area is supplied by 115-kV and 69-kV transmission lines emanating from the Montville Substation in Montville and the Card Substation in Lebanon. Two 345/115-kV autotransformers at Montville Substation and one 345/115-kV autotransformer at Card Substation serve as the main power-supply sources to the 115/69-kV system. This area is also reliant on local generation to reliably serve customer load demands. Planning studies concluded that long-term reliability needs of the area can be met by the installation of one additional 345/115-kV autotransformer located at a new Killingly Substation in Killingly. This autotransformer installation is the subject of CSC Docket No. 302. CL&P is also evaluating the potential need and added reliability benefit of rebuilding and/or converting some of the existing area 69-kV lines in eastern Connecticut to 115-kV.

Middletown Area: The Middletown area consists of a five-to-ten mile wide band east and west of the Connecticut River from Glastonbury to Old Lyme. The western section consists of a triangular-shaped area that runs from Middletown to Old Saybrook and back to the eastern part of Meriden. This area is reliant upon older 115-kV connected generation at Middletown Station to ensure a reliable source of energy. The long-term reliability needs of the area can be met by the installation of a 345/115-kV autotransformer at Haddam Substation. This autotransformer installation was the subject of CSC Petition No. 669. In addition, it is necessary to upgrade a 115-kV transmission line between the Manchester Substation in Manchester and the Hopewell Substation in Glastonbury.

Greater Hartford Area: The Greater Hartford area stretches north to the Massachusetts border, and is nestled between the Northwestern, Middletown, Manchester-Barbour Hill, and Southwest Connecticut areas. The transmission system supplying Hartford is adequate at this time to provide a reliable supply to the area. However, due to the thriving growth and future business opportunities in the Southington, Berlin, Newington, and Farmington areas, projected peak-load demands over the forecast period may result in reliability problems on the transmission system. Reliability improvements being studied include upgrading the existing 69-kV system at Black Rock Substation in New Britain to 115-kV.

Connecticut: Connecticut's 2004 summer-peak demand (including CL&P, UI and CMEEC) was approximately 6,900 MW. Connecticut's internal generation totals approximately 7,200 MW. The existing capability of the interconnecting tie-lines with neighboring systems can bring approximately 2,000 MW into Connecticut from adjacent states. Forced outages and the potential retirement of aging and uneconomic generation could result in situations where internal generation and imports together cannot meet the growing summer-peak energy demands. In addition, market redesign may result in higher electric energy costs in Connecticut if import capabilities remain significantly lower than internal peak demands for electricity. Reliability risks have CL&P and ISO-NE considering ways to increase the Connecticut import transfer capability using 345-kV transmission lines. ISO-NE recognized in its Regional Transmission Expansion Plans that southeast Massachusetts, where there is significant new merchant generation, lacks a transmission system that can efficiently integrate this generation into the New England 345-kV system. ISO-NE and other transmission providers, including CL&P, are actively considering the feasibility and benefits of expanding the 345-kV network into Connecticut. Under consideration is the construction of a second 345-kV transmission line between eastern Connecticut and Rhode Island/Massachusetts. Initial planning study results recommend the construction of a new

345-kV transmission line between the Card Substation in Lebanon and the Lake Road Substation in Killingly, continuing on across the state line to the West Farnum Substation in Rhode Island, and then onto a new termination point in Massachusetts. A 345-kV transmission line of this nature would provide Connecticut customers with the improved reliability of the 345-kV bulk power transmission grid, access to low-cost clean generation and reduced reliance on internal older generation.

To provide long-term reliable electric service to Connecticut's customers, it may be necessary to provide additional transfer capability into the state from other directions as well. This need will depend on the growth of customer demands for electricity and the additions or retirements of generation in Connecticut. Preliminary planning studies indicate that a new 345-kV transmission line into central Connecticut from western Massachusetts appears to provide Connecticut with appreciable reliability benefits. However, additional studies will have to be conducted before CL&P is able to bring forth a reliable and cost effective plan.

H. Emerging Issues

Wholesale Power Market Issues

New England has experienced significant transmission congestion since the wholesale competitive generation markets went into effect in May 1999. Higher energy prices have occurred due to generation that "must run" based upon voltage, thermal or stability problems. This is due to the lack of a robust transmission grid and sufficient low cost base-load generation. Historically, these higher prices have been shared by all New England customers. The practice of relying on local generation is a hold-over from the past design principles of utilities under the vertically integrated electric utility structure.

In March 2003, ISO-NE implemented a SMD in New England. The centerpiece of SMD is the adoption of Locational Marginal Prices ("LMP") for pricing energy. LMP is basically a congestion management system helping to administer both the available transmission capability on a regional basis and employing a mechanism to auction off financial rights over the transmission system. Higher energy prices that occur due to RMR generation as a result of transmission limitations are charged to specific ISO-NE-designated load areas within New England. The energy price signals provided via the congestion management system are designed to entice merchant generation or load reducing solutions in areas on the transmission system that exhibit higher energy costs. The impact of LMP on electric rates charged to Connecticut customers has been significant.

In addition ISO-NE will soon be able to independently send market signals to entice new generation to locate in chronically congested areas. FERC has ordered ISO-NE to develop a LICAP market. This new market is expected to be implemented in January 2006 and would identify the amount of generation capacity required in designated load areas. ISO-NE has cited the Connecticut load area as deficient in internal generation capacity and transmission transfer capability. While the final LICAP market design is not yet known, it could have a significant impact on Connecticut electricity prices, possibly even greater than the LMP costs incurred as part of the SMD energy market. Connecticut customers will likely incur significant cost increases as a result of this new market.

Pending the introduction of the LICAP market, some Connecticut generators have petitioned FERC for financial support by Connecticut customers in lieu of being allowed to shutdown. In a mature market scenario, generators that cannot economically compete in a competitive marketplace would shut down. Due to Connecticut's restrictive transmission capability, ISO-NE will not let certain generating units shut down. Certain Connecticut generating units have been designated as fixed-cost RMR resources. Under SMD, the additional costs of supporting these noncompetitive generating units, net of certain inframarginal revenues, are borne by the area that requires their operation. This market philosophy places additional costs on Connecticut customers.

The following RMR information was provided by ISO-NE to the Markets Committee on February 9, 2005. Costs before adjustment for any inframarginal revenues are:

Table V-1

Status of Fixed Costs Reliability Must Run Agreements for Connecticut Resource

Unit	Owner	Annual Fixed Cost	2005 CELT Summer Capability	$/kW-mo	Effective Date
Effective With Final FERC Approval					
Devon 11 -14	NRG	$ 19,568,124	120.58	13.52	01/17/2004
Middletown 2-4, 10	NRG	$ 49,617,744	770.12	5.37	01/17/2004
Montville 5, 6 10&11	NRG	$ 23,032,716	493.70	3.89	01/17/2004
Effective & Before Settlement Judge					
New Haven Harbor	PSEG	$ 47,368,806	447.89	8.81	01/17/2005
Bridgeport Harbor 2	PSEG	$ 19,012,116	130.50	12.14	01/17/2005
Filed at FERC - Not Effective					
Milford 1	Milford Power	$ 40,824,787	239.00	14.23	N/A
Milford 2	Milford Power	$ 40,797,848	253.50	13.41	N/A
Reliability Determination - No FERC Filing Yet					
Bridgeport Energy	Duke Energy	N/A	451.22	N/A	N/A
Rejected by FERC - Pending at Court of Appeals					
Wallingford 2-5	PPL	$ 25,661,138	175.92	12.16	N/A

Uncertainty in the Competitive Generation Marketplace

The establishment of a merchant generation marketplace continues to strain parts of the New England transmission system. Approximately 2,000 MW of new generation has been interconnected to the CL&P transmission system. An additional 1,100 MW of new generation has been approved for interconnection to the CL&P transmission system. Further, approximately 1,000 MW of proposed generation is under study to interconnect with the CL&P system. This merchant generation can provide both economic and environmental benefits to the region, but the potential new sources of generation could strain the existing transmission system when plant size and interconnection location are not optimized. In virtually all cases, when new merchant generation is installed within the state, additional reinforcements to the transmission system will be necessary.

The recent expansion of the competitive generation marketplace has primarily relied upon natural gas as the fuel supply of choice. This heavy reliance on one type of fuel could place electric generation in jeopardy during times of fuel shortages or interruptions in delivery. The primary use of natural gas for generation might result in an over-dependence and lack of diversity that could result in a serious reliability problem.

Another issue facing Connecticut is the long-term viability of several fossil fueled generating stations. Over the past few years there has been a concentrated effort to reduce the environmental impact of these units. Ultimately, this could lead to the closure of these stations. Further, the financial health of generating companies and their willingness to operate and maintain their units in a competitive generation marketplace leads to uncertainties of generation availability to serve customer load.

In 2004, Devon units 7 & 8 were placed on deactivated reserve. NRG also notified CL&P of the potential to shut down Norwalk Harbor units 1 and 2 and the Cos Cob generating units.

In today's marketplace it is difficult to know with certainty where the power will be generated to meet customer electric energy demands in the short term let alone the long term. This poses an enormous challenge for transmission planners. Planners are straddled with the real possibility of generator retirement decisions, being made on short notice by companies with no obligations to serve and the multiple year lead times to build transmission infrastructure or new generating plants. Therefore transmission plans must be sufficiently flexible so the grid is capable of accessing multiple resources to move the power from where it is generated to where it is consumed.

For a variety of reasons Connecticut finds itself with a number of issues resulting in higher power costs. Power prices are at historic highs across New England because the price of natural gas and oil, which drive the price of electricity, are at historic highs. If natural gas and oil prices were to decline significantly, all other things being equal, electricity prices throughout New England would decline, too.

Connecticut's power prices are projected to decline less before 2006 than elsewhere in New England due to fixed-cost RMR contracts and the potential for high congestion costs, both discussed above. Potential congestion costs arise because at times, due to system conditions, the generation setting energy prices in Connecticut can be higher than the generation setting energy prices elsewhere in New England. At these times it is likely that the marginal generation in Connecticut is coming from units with relatively high heat rates which are burning 0.3% sulfur residual oil, or newer internal combustion units which are burning natural gas or old internal combustion units which are burning jet kerosene while elsewhere in New England marginal generation is coming from units with a relatively low heat rate that is burning natural gas.

Further upward pressure on Connecticut power prices will result from the proposed introduction of LICAP in January 2006. As discussed previously, this market is thought to be needed to financially stimulate generation construction and retention. While the start date is not certain and the proposed market design is presently being litigated before FERC, what is known is that capacity prices would be determined locally through an administrative process taking into account local needs, local resources and how much power can be provided from outside the local area. This new market has the potential to add significantly to the price for power in Connecticut as compared to elsewhere in New England. This is because the sum of the amount of local supply and the power which can be brought into Connecticut relative to what is needed is proportionately less than elsewhere in New England.

Fuel diversity is also a concern, but not a direct power price driver. So long as natural gas or oil-fired generation is setting the marginal energy price, fuel diversity will not lower prices. However, as the number of fuels used to power significant amounts of generation increases, the likelihood that one type of fuel-supply shortage can cause operating constraints declines dramatically. Adequate fuel-transportation infrastructure, fuel-switching capability and good fuel-inventory controls can all help ameliorate perceived poor fuel diversity.

The CSC has the difficult task of balancing the competitive forces for generation expansion and the need to integrate transmission projects that can access power resources and reliably serve customer demands.

New Reliability Standards

On April 5, 2004, a joint United States/Canada task force issued a report on the August 14, 2003 blackout that affected fifty million people in the northeast and midwest United States and Canada. The report findings focused on the importance of maintaining a reliable electric system for safety, economic and security reasons. The task force recommended creating reliability standards that are measurable and enforceable. The federal government agreed with the task force's findings and, while recognizing that many aspects of reliability fall under state jurisdiction, committed to working on the issues with Canada, Mexico, and the states. It appears likely that in the near term all reliability standards will be federally enforced with punitive measures for non-compliance.

New Technologies

A term widely used to categorize alternatives to central station power supply (i.e., large power plants) is Distributed Resources ("DR"). The opening up of electricity markets and the escalating environmental implications of power-plant emissions have opened doors for DR to become a central energy trend. The conventional options of the past include combustion turbines, and the new DR technologies include fuel cells, solar photovoltaic panels, batteries and wind turbines. Specific technologies such as diesel and combustion turbines are commercially available and their costs are relatively low, but these technologies produce high levels of NOx, SO_2 and CO_2 which will limit their future use. Microturbines and fuel cells have better emission characteristics than combustion turbines and diesel engines, but CO_2 emissions are still considerable, and these technologies still have high capital costs and limited availability. Renewable energy sources, such as solar and biomass are also part of the picture of DR technologies and these sources have found small niche applications in Connecticut. CL&P believes that DR technologies and C&LM programs should be part of the total portfolio of energy options that are deployed in Connecticut to make the state less dependent on fossil fuels into the future.

As competition and merchant generation expand in the northeast United States, the need to transfer more power, longer distances, over existing, rebuilt and new transmission lines will increase. This change presents additional challenges in controlling heavier power flows over transmission lines, minimizing losses, maintaining voltage levels and ensuring system reliability and stability. With a goal of maximizing the utilization of existing facilities, new technologies such as Flexible Alternating Current Transmission System ("FACTS") devices will potentially be required. Existing transmission controls may not be able to respond sufficiently fast to changing network conditions. FACTS devices combine high-speed solid state electronic switches, microprocessors, powerful computers, advanced automation and communications as well as innovative power-system analysis software for advanced system-control capability. A FACTS device called a static synchronous compensator ("STATCOM") was installed at the Glenbrook Substation and became operational in 2004.

An additional application of a similar technology, but of smaller scale, is the use of dynamic VAR ("DVAR") technology at the Stony Hill Substation, in Brookfield, and Bates Rock Substation, in Southbury. The DVAR devices are smaller FACTS devices that are strategically placed electrically near the distribution system. They provide dynamic voltage control and also enable rapid switching of conventional capacitor banks. One of the advantages of this technology is that the DVAR power electronics are trailer-mounted, which can easily be moved to a new site as system needs change.

As new technologies emerge, their operating characteristics will be screened to match them to specific transmission network needs. To consider these new technologies on an electrical network basis they must be reliable and cost-effective, and must intermesh well with the overall strategy and plan for expanding system capabilities. CL&P is committed to utilize appropriate technologies that can solve specific problems. CL&P continues to monitor the development of emerging technologies and will employ those into the electric system which mature to become reliable, economic, commercially available products to improve system reliability and as an alternative to upgrading existing facilities or expanding the electrical network.

New Transmission Conductor and Cable Technologies

Several high-temperature, low-sag types of conductors have emerged which have greater current- and power-transfer capacity than conventional Aluminum Conductor Steel Reinforced ("ACSR") conductors. Two categories exist. Those conductors which have been fully developed, and are commercially available with the required hardware and tooling accessories, and industry standards have been set for manufacturing, testing and installation. Stranded conductors such as Aluminum Conductor Steel Supported ("ACSS"), and ACSS with trapezoidal strands to maximize the conductive aluminum content ("ACSS-TW"), are types in this category. CL&P has successfully installed ACSS conductors on several projects, allowing re-use of many existing structures in line upgrade projects. The second category includes conductors which have been developed to the point where field trials have shown potential, and conductors are entering the commercial market. Several types of new conductors similar to ACSR and ACSS, but composed of different combinations of special-alloy aluminum (e.g., zirconium, yttrium) and steel (e.g., nickel), have reached this stage in the Japanese market. In the United States, emerging variations of such conductors also employ a high strength core of special materials including carbon fibers. One such conductor is the 3M Aluminum Conductor Composite Reinforced ("ACCR") cable. This conductor uses a 3M Aluminum Matrix Composite material core which is as strong as steel and has lower electrical resistance. 3M publications state that the conductor has a higher current carrying capacity with less sag. Research and some limited field installations have begun on the 3M and other conductors in this country which may lead to the next generation of conductors to reach wider commercial status.

There continue to be advances in underground transmission cable system technologies, methods of installation, and improvements in their capacity. High voltage cables exhibit a significant amount of charging current compared to overhead transmission lines. The capacitance of high voltage cable systems adds complexity to the planning and operation of the power system. Detailed analyses are required to determine the acceptability of transmission cables in a predominantly overhead system. New applications and industry research have focused primarily on cross-linked polyethylene ("XLPE") insulated cables. Though still more costly to install than high-pressure fluid-filled ("HPFF") cables in pipes, XLPE cables avoid the environmental concerns associated with an insulating fluid release and the maintenance cost of HPFF systems and offer significantly lower cable charging power requirements. These differences will potentially enable XLPE cables to be applied in greater lengths than is technically feasible with HPFF cable systems in urban centers. In fact, XLPE cable technology has progressed and developed throughout the 1990s such that it is now considered reliable and proven for uses up to 230-kV, and sufficiently reliable at 345-kV that CL&P and UI have proposed to incorporate 24 linear miles (forty-eight circuit miles) of 345-kV XLPE cable in the Middletown to Norwalk Project (i.e., CSC Docket 272).

Research and development of superconducting cables is continuing, to date only prototype designs have been produced for small demonstration applications. This new technology is not yet commercially available for transmission network applications.

National Discussion on Transmission Capability

National discussion on transmission capability has focused on the decline of investment in transmission versus other segments of the industry over the past twenty years. There is a concern that transmission construction continues to lag other segments of the industry, (i.e., load and generation expansion). The interconnected transmission system in the U.S. is one of the most complicated systems ever built by man. Nationally, the integration of load, generation and transmission has resulted in the most reliable electric system in the world. In the past, much of the focus was on the need for local transmission to serve local needs. Today, external pressures from a variety of industry participants are fostering changes that will alter this focus to be more regional in scope. There is a growing need, driven by customer demands for greater reliability and economics to have a transmission system that has far greater capability to move larger blocks of power, greater distances, more reliably and at lower cost.

CL&P continues to conduct system planning studies to enhance its transmission system to provide better customer service more economically. CL&P believes that new transmission investment should follow efforts to maximize the use of existing transmission facilities and to use alternative technologies. CL&P continues to support the use of high voltage transmission lines to meet local reliability needs and the increased need to transfer energy on a regional basis. It is possible that the new transmission infrastructure needed to address reliability problems could increase a customer's transmission costs; however, it will allow greater access to lower cost regional generation, help to ensure a reliable power source, and keep overall electric energy costs low.

I. Electric and Magnetic Fields

In response to public concern over possible adverse health effects from power-frequency electric and magnetic fields ("EMF"), the federal government conducted a 5-year national research program, which concluded in 1999. The National Institute of Environmental Health Sciences ("NIEHS") reported subsequently to Congress that the scientific evidence suggesting that extremely low frequency EMF exposures pose any health risk is weak and insufficient to warrant aggressive regulatory concern.

More recently, the Connecticut General Assembly enacted P.A.-04-246, which requires costly and burdensome changes in transmission line design; and the CSC adopted new EMF Best Management Practices ("BMP") effective December 21, 2004. The CSC has since announced its intent to revise its BMP again, with the assistance of an expert consultant and an opportunity for public comment. CL&P looks forward to that opportunity to assist the CSC in improving the current BMP, which reflects some technical misunderstandings. CL&P continues to support and apply EMF Best Management Practices.

J. Connecticut Summary

Below are brief descriptions of Table V-2 through Table V-5 which provide information regarding CL&P's transmission projects. Following these descriptions are lists of planned substation and transmission capacitor bank projects. During the forecast period, additional transmission projects beyond those shown here may be justifiable to enhance reliability or provide efficient means to transmit electric energy. The estimated in-service dates for new facilities listed in the tables may vary through time as the dynamics of the system change.

Table V-2 - Transmission Circuits Under Construction in Connecticut, contains four entries.

Table V-3 - Approved Transmission Circuits in Connecticut which are not yet under Construction, contains one entry.

Table V-4 - Proposed Transmission Circuits in Connecticut on file with the Connecticut Siting Council, contains twenty-five entries.

Table V-5 - Other Proposed Transmission Circuits in Connecticut, contains nineteen entries.

Substation Projects

From 1982 to 2004, CL&P's total number of substations was reduced from 331 to 235 primarily by conversions of distribution feeders to a higher voltage, thereby eliminating the need for many lower voltage substations.

Planned substation projects	Estimated in-service date
Install a new 345-kV Kleen Switching Station in Middletown	TBD[3]
Install a new 345-kV South Kensington Switching Station in Berlin	TBD[4]
Expand the existing 345-kV Long Mountain Switching Station in New Milford	2005
Expand the existing 115-kV Haddam Substation in Haddam	2005
Install a new 345-kV Haddam Substation in Haddam	2005
Install a new 115-kV Shunock Substation in Stonington	2005
Expand the existing 345-kV Plumtree Substation in Bethel	2006
Install a new 345-kV Norwalk Substation in Norwalk	2006
Install a new 345/115kV Killingly Substation in Killingly	2006
Expand the existing 115-kV Triangle Substation in Danbury	2007
Expand the existing 138/115-kV Norwalk Harbor Substation in Norwalk	2007
Install a new 115-kV Wilton Substation in Wilton	2007
Install a new 115-kV Stepstone Substation in Guilford	2007

[3] The Kleen Switching Station associated with the proposed Kleen Energy generating plant has been delayed due to delays in construction of the plant.

[4] The South Kensington 345-kV Switching Station associated with the proposed Meriden Power generating plant has been delayed due to delays in construction of the plant.

Planned substation projects (continued)	Estimated in-service date
Modify the existing 115-kV Norwalk Substation in Norwalk	2008
Install a new 345-kV Barbour Hill Substation in South Windsor	2008
Expand the existing 115-kV Glenbrook Substation in Stamford	2008
Install a new 345/115-kV East Devon Substation in Milford	2009
Expand the existing 345-kV Norwalk Substation in Norwalk	2009
Modify the existing 115-kV Devon Substation in Milford	2009
Install a new 345-kV Beseck Switching Station in Wallingford	2009
Expand the existing 345-kV Scovill Rock Switching Station in Middletown	2009
Expand the existing 115-kV Glenbrook Substation in Stamford	TBD
Expand the existing 115-kV Norwalk Harbor Station in Norwalk	TBD
Expand the existing 345-kV Card Substation in Lebanon	TBD
Install a new 115-kV Jack's Hill Substation in Oxford	TBD
Install a new 115-kV Windsor Substation in Windsor	TBD
Install a new 115-kV West Southington Substation in Southington	TBD
Install a new 115-kV South Cheshire Substation in Cheshire	TBD
Install a new 115-kV Goshen Substation in Goshen	TBD
Install a new 115-kV Bradley Substation in Middletown	TBD
Install a new 115-kV Walnut Hill Substation in the Salem area	TBD

Transmission Capacitor Bank Projects

Substation	Size of Capacitor	Estimated in-service date
Bunker Hill	One 50-megaVAR unit	TBD

This project involves proposed shunt capacitor banks for the 115-kV transmission system.

K. Definitions

Bundling - change two parallel 3-conductor circuits to operate as a single 6-conductor circuit.

Circuit - a system of conductors (three conductors or three pairs of conductors) through which an electrical current is intended to flow and which may be supported above ground by transmission structures or placed underground.

Conversion - change an existing transmission line for use at a higher voltage, sometimes requiring the installation of more insulators. (Lines are sometimes pre-built for future operation at the higher voltage.)

Line - a series of overhead transmission structures which support one or more circuits: or in the case of emergency underground construction, a single electric circuit.

Rebuild - replacement of an existing overhead transmission line with new structures and conductors generally along the same route as the replaced line.

Reconductor - replacement of existing conductors with new conductors, but with little if any replacement or modification of existing structures.

Reinforcement Upgrade - any of a number of approaches to improve the capacity of the transmission system, including rebuild, reconductor, conversion, and bundling methods.

TABLE V-2: Transmission Circuits Under Construction in Connecticut

(as of January 1, 2005)

Transmission Project	Build-Type (1)	Area	Voltage (kV)	Length (mi)	In-Service Date
Plumtree S/S, Bethel – Norwalk S/S, Norwalk (new) (2)	OH	Southwestern	345	8.6	2006
Plumtree S/S, Bethel – Norwalk S/S, Norwalk (new) (2)	UG	Southwestern	345	11.8	2006
Plumtree S/S, Bethel – Norwalk S/S (reconfigure 1470/1565 lines) (2)	OH	Southwestern	115	1.3	2006
Plumtree S/S, Bethel – Norwalk S/S (reconfigure 1470/1565 lines) (2)	UG	Southwestern	115	10.0	2006

Note (1): OH – Overhead, UG – Underground, UW – Underwater
Note (2): CSC Docket 217

TABLE V-3: Approved Transmission Circuits in Connecticut Not Yet Under Construction

(as of January 1, 2005)

Transmission Project	Build-Type (1)	Area	Voltage (kV)	Length (mi)	In-Service Date
Norwalk Harbor Station, Norwalk - Northport Station, Northport (N.Y.) (replace) (2)	UW	Norwalk-Stamford	138	5.8	2007

Note (1): OH – Overhead, UG – Underground, UW – Underwater
Note (2): CSC Docket 224

TABLE V-4: Proposed Transmission Circuits in Connecticut on File with the Connecticut Siting Council

(as of January 1, 2005)

Transmission Project	Area	Voltage (kV)	Length (mi)	In-Service Date
East Devon S/S, Milford (new substation) - Singer S/S, Bridgeport (new substation) (UI), (new) (1) (2)	Southwestern	345	3.1	2009
Singer S/S, Bridgeport (new substation) - (UI), Norwalk S/S (new) (1)	Southwestern	345	15.5	2009
Plumtree S/S, Bethel – Triangle S/S, Danbury (rebuild) (4)	Southwestern	115	1.8	2007
Plumtree S/S, Bethel – Triangle S/S Danbury (rebuild) (4)	Southwestern	115	1.8	2007
Devon S/S, Milford – Wallingford Station Wallingford, (rebuild a portion of #1640) (1)	Southwestern	115	27.0	2009
Devon S/S, Milford – June St. S/S, Woodbridge (UI) (rebuild a portion of #1685) (1) (2)	Southwestern	115	13.4	2009
North Haven S/S, North Haven (UI) – Wallingford Station, Wallingford (rebuild a portion of #1630) (1) (2)	Southwestern	115	0.3	2009
North Haven S/S, North Haven (UI) – Branford S/S, Branford (rebuild a portion of #1655 line) (1) (2)	Southwestern	115	1.3	2009
East Devon S/S, Milford – Devon S/S, Milford (new) (1)	Southwestern	115	1.3	2009

Transmission Project	Area	Voltage (kV)	Length (mi)	In-Service Date
East Meriden S/S, Meriden-North Wallingford S/S, (CMEEC) (rebuild a portion of #1466) (1)	Southwestern	115	1.4	2009
June St.,S/S,Woodbridge, (UI) – Southington S/S, Southington (rebuild a portion of #1610), (1) (2)	Southwestern	115	10.5	2009
Devon S/S, Milford – Devon Switching Station, Milford, (UI) (rebuild) (1) (2)	Southwestern	115	0.1	2009
Devon S/S, Milford – Devon Switching Station, Milford, (UI) (rebuild) (1) (2)	Southwestern	115	0.1	2009
Southington S/S, Southington - Wallingford S/S, Wallingford (rebuild a portion of #1208) (1)	Southwestern	115	2.9	2009
Devon S/S, Milford – Derby Jct., Shelton- Beacon Falls S/S, Beacon Falls (reconductor portion of #1570) (1)	Southwestern	115	3.8	2009
Bunker Hill S/S, Waterbury – Baldwin Jct., Waterbury- Beacon Falls S/S, Beacon Falls (reconductor a portion of the #1575) (1)	Southwestern	115	3.8	2009
Devon S/S, Milford – Lucchini Jct.,Meriden- Southington S/S,Southington (1) (3)	Southwestern	115	23.9	2009
Scovill Rock S/S, Middletown – Chestnut Jct., Middletown (new) (1)	Middletown	345	2.6	2009

Transmission Project	Area	Voltage (kV)	Length (mi)	In-Service Date
Oxbow Jct., Haddam – Beseck S/S, Wallingford (new switchyard) (new) (1)	Middletown	345	7.0	2009
Black Pond Jct., Middlefield – Beseck S/S, Wallingford (new switchyard) (new) (1)	Middletown	345	2.8	2009
Black Pond Jct., Middlefield – Beseck S/S, Wallingford (new switchyard) (new) (1)	Middletown	345	2.8	2009
Beseck S/S., Wallingford (new switchyard) - East Devon S/S (new substation), Milford (new) (1)	Middletown	345	33.4	2009
Haddam S/S – East Meriden S/S, Meriden (rebuild a portion of #1975) (1)	Middletown	115	8.4	2009
Norwalk S/S, Norwalk - Glenbrook S/S ckt 1, Stamford (new) (5)	Norwalk-Stamford	115	8.7	2008
Norwalk S/S, Norwalk - Glenbrook S/S ckt 2, Stamford (new) (5)	Norwalk-Stamford	115	8.7	2008

Note (1): CSC Docket 272
Note (2): CL&P portion
Note (3): Remove a major portion of line1690
Note (4): CSC Petition 702
Note (5): CSC Docket 292

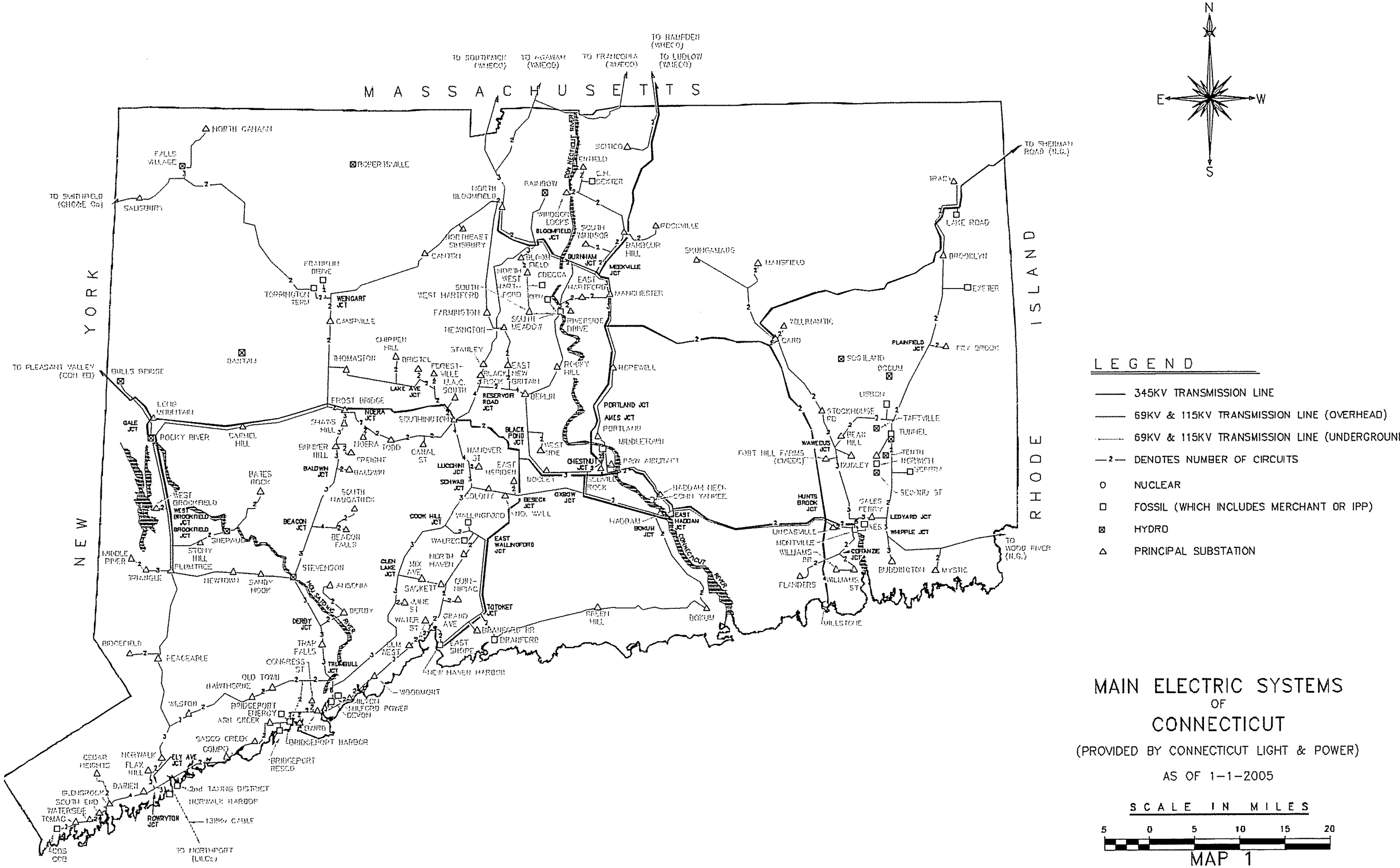
TABLE V-5: Other Proposed Transmission Circuits in Connecticut

(as of January 1, 2005)

Transmission Project	Area	Voltage (kV)	Length (mi)	In-Service Date
Tunnel S/S, Preston – Ledyard Jct., Ledyard (rebuild & upgrade to 115-kV)	Eastern	69	8.5	TBD
Ledyard Jct., Ledyard – Gales Ferry S/S, Ledyard (upgrade to 115-kV)	Eastern	69	1.6	TBD
Gales Ferry S/S, Ledyard – Montville Station Montville (upgrade to 115-kV)	Eastern	69	2.4	TBD
Ledyard Jct., Ledyard – Buddington S/S, Groton (CMEEC), Groton (upgrade to 115-kV) (1)	Eastern	69	4.7	TBD
Card S/S, Lebanon – Wawecus Jct., Bozrah (rebuild)	Eastern	115	12.7	TBD
Card S/S, Lebanon – Lake Road Station, Killingly (new)	Eastern	345	29.2	TBD
Lake Road Station, Killingly – West Farnum Road S/S, R.I. (National Grid) (new)	Eastern	345	7.6	TBD
Norwalk Harbor Station, Norwalk - Glenbrook S/S , Stamford (new)	Norwalk-Stamford	115	9.2	TBD
South End S/S, Stamford – Tomac S/S, Greenwich (reconductor a portion of the #1750)	Norwalk-Stamford	115	0.4	TBD

Transmission Project	Area	Voltage (kV)	Length (mi)	In-Service Date
Manchester S/S, Manchester – Hopewell S/S Glastonbury (reconductor)	Middletown	115	7.0	2006
East Meriden S/S, Meriden – North Wallingford S/S, Wallingford (reconductor the westerly portion of the #1466)	Middletown	115	0.5	TBD
Schwab Jct., Wallingford – Colony S/S (CMEEC), Wallingford	Middletown	115	1.5	TBD
Manchester S/S, Manchester – Barbour Hill S/S, South Windsor (rebuild)	Manchester-Barbour Hill	115	7.5	TBD
Southington S/S, Southington – Schwab Jct., Wallingford (unbundle/rebuild)	Southwestern	115	6.3	TBD
Oxbow Jct., Haddam – Beseck Jct., Wallingford (unbundle/rebuild)	Southwestern	115	14.7	TBD
Colony S/S (CMEEC), Wallingford North Wallingford S/S (CMEEC) (unbundle)	Southwestern	115	2.4	TBD
Frost Bridge S/S, Watertown - Bunker Hill S/S, Waterbury	Southwestern	115	3.9	TBD
Frost Bridge S/S, Watertown – Walnut Jct., Thomaston (new)	Northwestern	115	6.4	TBD
Frost Bridge S/S, Watertown - Campville S/S, Harwinton (rebuild)	Northwestern	115	10.3	TBD

Note (1): Includes CMEEC portion



MAIN ELECTRIC SYSTEMS OF CONNECTICUT

(PROVIDED BY CONNECTICUT LIGHT & POWER)

AS OF 1-1-2005

MAP 1